DECLARATION OF JAMES E. STAUDT, PH.D., CFA

I, James E. Staudt, declare under penalty of perjury that the following is true to the best of my knowledge, information and belief:

2. I am the owner and president of Andover Technology Partners (ATP), a consulting business that commenced operation in 1997. I am an engineer with a Chartered Financial Analyst (CFA) designation and decades of experience in all aspects of energy and air pollution control in the electric generating unit (EGU) sector, as reflected in my CV attached hereto as Attachment 1. My graduate studies at MIT included research in coal combustion and turbomachinery design. Over the course of my career, I have personally developed, designed, supplied, commissioned, and advised on air pollution control technology utilized in a variety of industrial sectors, but especially coal-fired power plants. I have written numerous publications, reports for clients, and other documents on emissions control technology for various industrial applications. I have testified in three federal courts as an expert on the cost, installation (including scheduling and planning) and capabilities of emissions control technology. I have also testified in several arbitration hearings and public hearings on the same. I have also published reports, affidavits and other documents on the engineering and economic factors that impact the deployment of air pollution controls and the resources and time needed to meet regulatory requirements. A list of my publications is included in Attachment 1.

3. As a consultant, I have also advised facility owners, state and federal agencies, and suppliers of emissions control technology on the technical performance, cost, and application of emissions control technology to both non-EGU and EGU facilities. My work contributed directly to Illinois'

landmark 2006 mercury (Hg) control rule and multi-pollutant standards for coal-fired power plants. I received a 2007 US Environmental Protection Agency (US EPA) Science and Technology Achievement Award for work performed with US EPA scientists and engineers that directly relates to Hg and air toxics control from coal-fired power plants. I have published an *ex post* analysis of the costs to comply with the 2012 Mercury and Air Toxics Standards (MATS) rule that was submitted with a declaration to the United States Court of Appeals for the District of Columbia Circuit in 2015. I have also published analysis of the 2023 proposed MATS revision.[1]

4. With this background, I offer the following opinions regarding US EPA's Final Rule - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review (the "MATS Update Rule"), in response to the motion that have been filed to stay the Rule.[2]

EPA'S PROJECTED UPGRADES FOR CONTROLS ARE FEASIBLE WITHIN THE COMPLIANCE PERIOD, WITH THE MAJORITY OF RESOURCE COMMITMENTS NOT REQUIRED UNTIL A PERIOD OF TIME LIKELY AFTER THE END OF LITIGATION OVER THE RULE (ESTIMATED FOR THIS ANALYSIS AS ROUGHLY SUMMER 2026).

5. The rule provides three years from the effective date of July 8, 2024, to comply, with a possible fourth-year extension from the permitting authority. EPA also provided a three-year compliance timeline (with a possible fourth year extension) in the 2012 MATS rule, which involved control of more pollutants and many more impacted units than the new MATS Update Rule.

[1] Staudt, J., *Assessment of Potential Revisions to the Mercury and Air Toxics Standards, for Center for Applied Environmental Law and Policy*, June 15, 2023, available at: www.andovertechnology.com/articles-archive.
[2] 89 Fed. Reg. 38508 (May 7, 2024).

"The 2012 MATS Final Rule was ultimately implemented over the 2015-2016 timeframe without challenges to grid reliability."[3] In the following paragraphs I will discuss the reasons why the time period for compliance with this Rule is more than adequate.

A. The equipment can be installed within the timeframe permitted by the Rule.

6. The vast majority of units are already in compliance with the Rule and will not require any modifications to their equipment. Therefore, very few units are expected to require modifications. In this final rule, EPA forecast 33 cases of expected upgrades to reduce emissions of filterable particulate matter (fPM).[4] This is consistent with the findings of my independent analysis of the rule for ATP. In 2023, ATP published a report that analyzed the proposed rule.[5] In that report, ATP determined that for a fPM emission limit of 0.010 lb/MMBtu, 34 units might require a change to fPM equipment, ranging from upgrades to electrostatic precipitators (ESPs), to filter media upgrades, and in only two cases, possibly a new baghouse. For both estimates this is a small fraction of the 296 coal units projected to be in operation in 2028. All of these equipment installations can be performed well within the allotted time of three years or four years (with the extension) from the effective date of the rule, July 8, 2024. I have reviewed both the resources and timeline for installation of various control technologies,

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[3] 89 Fed. Reg at 38519.
[4] 89 Fed. Reg. at 38522.
[5] Staudt, J., *Assessment of Potential Revisions to the Mercury and Air Toxics Standards, for Center for Applied Environmental Law and Policy* (June 15, 2023), available at: www.andovertechnology.com/articles-archive.

including technologies impacted by this rule.[6] Many of these equipment changes, such as media upgrades or more modest ESP upgrades, only require a few months to perform. More complex ESP upgrades may require up to 18 months or so. A new baghouse can be installed in around two years from engineering through construction,[7] a year less than the default compliance timeline and about half of the time available if an extension is permitted. Therefore, the rule allows more than enough time for even the most complex installations. Continuous emissions monitoring systems for fPM (PM CEMS) can be fully installed in well below a year, typically around six months from start to finish.

7. Additional Hg controls are needed only on some lignite-fired units. EPA identified 22 lignite units that may need to make changes to achieve the new Hg limit of 1.2 lb/TBtu, and this estimate too is consistent with my 2023 analysis for ATP. For most of these units, compliance will entail increasing activated carbon injection rates or changing fuel additives or scrubber chemicals. Any equipment changes necessary to accommodate these modifications are relatively minor, at most requiring changes in blowers, carbon metering valves, or larger sorbent storage vessels. All of these changes can be performed well within a year.

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[6] *See* Staudt, J., "Engineering and Economic Factors Affecting the Installation of Control Technologies– An Update", for US EPA Clean Air Markets Division, December 15, 2011; "Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies", EPA-600/R-02/073, October 2002. ATP was a key contributor to this report.

[7] Sargent & Lundy, "IPM Model – Updates to Cost and Performance for APC Technologies Particulate Control Cost Development Methodology", Final, April 2017, Project 13527-001, page 10. The Presque Isle Power Plant baghouse installation took under two years. *See* Staudt, J., "Engineering and Economic Factors Affecting the Installation of Control Technologies– An Update", for US EPA Clean Air Markets Division, December 15, 2011, page 32.

B. The timeline for installing the controls is reasonable given manufacturing and technology availability and supply chain factors.

8. As I will demonstrate in the following paragraphs, the level of effort required under this Rule is very small compared to the effort required to comply with prior clean air rules. The prior rules had similar timelines but required a much greater effort from industry, and I therefore do not envision there being a significant challenge for suppliers. I also do not envision a significant reliability or availability impact to the coal fleet in light of the small portion of the fleet that is impacted and the generally modest effort needed for the affected units. The modest additional demand for equipment will be primarily for standard equipment used in material handling. The only specialized equipment is filter bag material, and the increase in demand for filter bag material will be small compared to the total supply of filter bag material. Attachment 1 to the Technical Memorandum[8] from the proposed rule shows those EGUs that EPA projected would need to make changes to comply with the updated MATS rule. Of the 263 units, 132 units were already equipped with baghouses without the MATS Update Rule. EPA only forecast two additional baghouses as a result of the updated MATS rule, which is consistent with ATP's 2023 estimate. Filter media upgrades were forecast to be needed by 11 units in ATP's 2023 forecast and 8 units for EPA's forecast provided in the proposed rule. EPA forecast 2 filter bag upgrades and 6 units that would increase standard bag replacement frequency. As a result, whatever increase in filter media is prompted by the

[8] Attachment 1, EPA-HQ-PAR-2018-0794-6919_attachment_1, to 2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category (2024 Technical Memo).

rule is well within the capabilities of the industry to supply filter bag material.

9. Supply of activated carbon is more than adequate to address the expected increase in demand for activated carbon resulting from the rule because this impacts only a few units. EPA identified 22 lignite fired units that will need to make modifications to reduce Hg emissions. Currently, hundreds of coal units utilize activated carbon injection, and especially the advanced sorbents that have been developed in the years since the 2012 MATS rule to address situations like higher SO_3 levels, use of trona for dry sorbent injection (DSI), and higher activities for lower treatment rates.[9] Carbons to address elevated SO_3 levels were developed not only to address situations with lignite units, but also for units using bituminous coals or units using Powder River Basin coals that have SO_3 flue gas conditioning. So, these activated carbons are already widely used. In fact, these advanced carbons have become standard due to the typically lower treatment rates offered compared to the older carbon types that were available in 2012. So, this constitutes a very modest impact on activated carbon demand. The supply of these carbons is more than adequate to address the increased demand from the rule.

C. There will be no shortage of vendors and skilled labor.

10. I have personally been involved in the deployment of air pollution control technology and have written several reports for US EPA on resources needed for installation of air pollution control equipment.

11. Vendors will be available for this Rule. There are multiple vendors for all of the equipment that will be deployed to comply with this rule. These are all

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[9] Staudt, J., *Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants, for* Center for Applied Environmental Law and Policy (CAELP), August 19, 2021, pages 47-53.

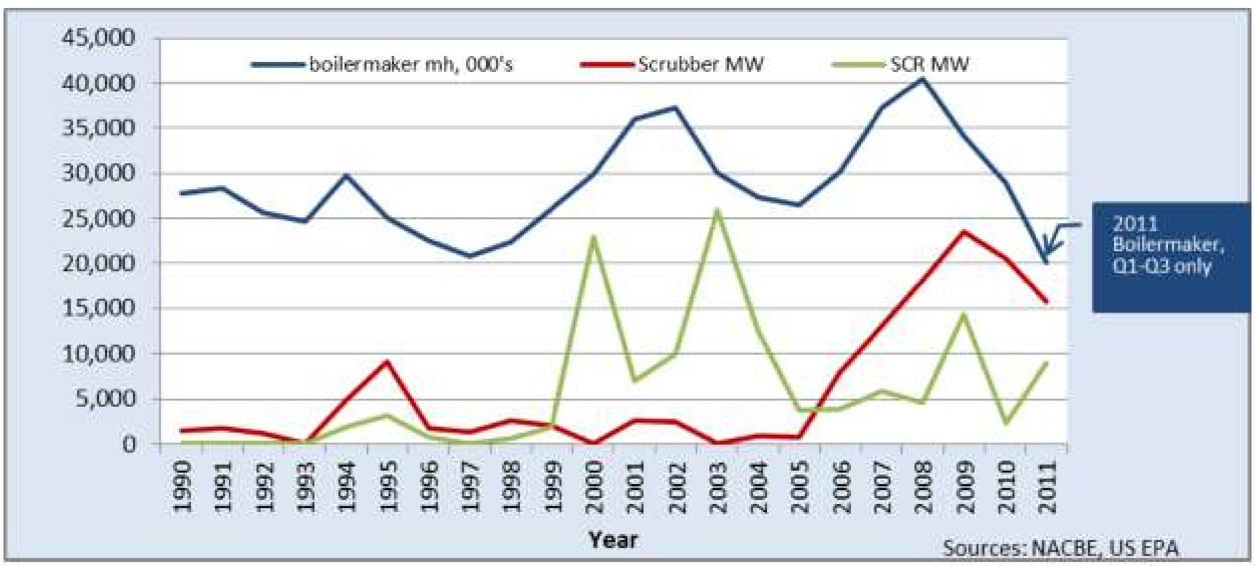
experienced vendors that supported the industry with meeting the 2012 MATS rule requirements that impacted all coal units with control requirements for Hg, non-Hg metals, and acid gases. In contrast to the 2012 MATS rule that impacted hundreds of coal units, this new rule impacts only a few dozen units.

12. Compared to prior clean air rules, demand for labor to comply with this rule will be very modest. As will be discussed in more detail later, the cost of this rule, which is indicative of the demand for labor, is very small compared to the cost of prior clean air rules. In any event, in the past, skilled labor has responded swiftly to increases in demand and therefore likely will again in this case. And, as will be discussed further later in this declaration, because the demand for construction labor will not be significant prior to late 2026, there is no need for owners and operators to take major action during the litigation period.

13. Boilermakers are skilled laborers who play a key role in the installation of equipment on EGU boilers, and they will have an important role in the installation of equipment for this rule. History with prior rules provides clear evidence of the increased supply of labor when installations of equipment for clean air rules were being implemented. As shown in Figure 1, in the mid-late 1990s boilermaker employment dwindled in response to low construction activities. But, starting in the late 1990s, boilermaker employment grew due to increased demand. Boilermakers were essential for the installation of the selective catalytic reduction (SCR) systems that peaked in the utility industry in 2000 and 2003 and for scrubbers that peaked in installation in 2009. This was in response to the NOx SIP Call, the Clean Air Interstate Rule (CAIR), and the Cross-State Air Pollution Rule (CSAPR) which were being implemented during this period starting in the early 2000s

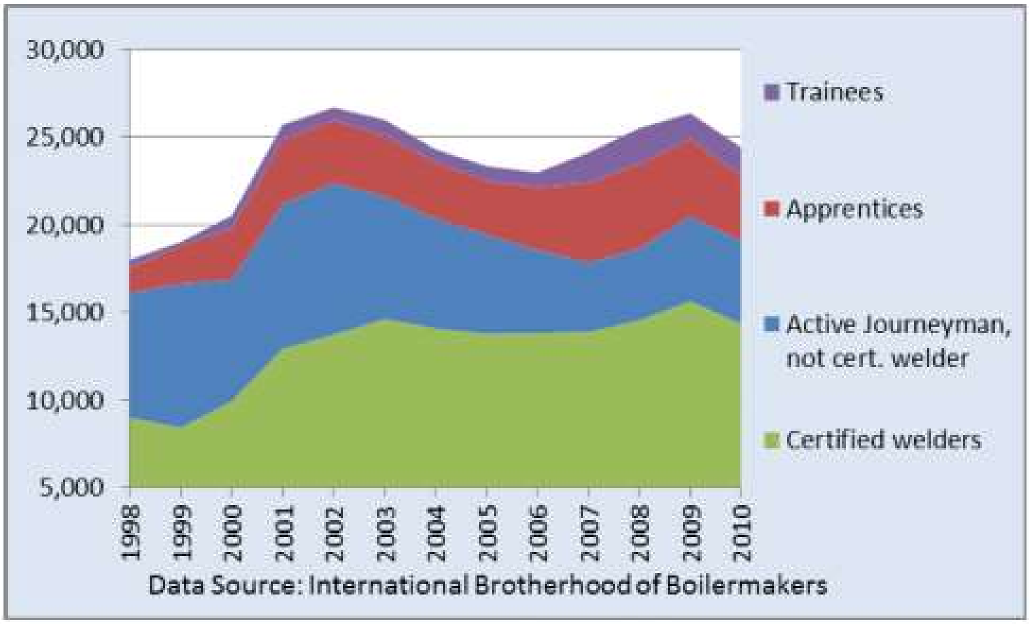
through to about 2010. As Figure 1 shows, construction boilermaker man-hours were closely related to installation of this equipment, and Figure 2 shows that boilermaker trade membership grew quickly between 1998 and 2002 as demand for boilermakers increased to meet the needs for coal EGU retrofits of SCR as well as rapid increases in the installation of gas-fired EGUs.[10] This response in labor supply to demand demonstrates that the supply of labor responded well to the increase in demand over that period of time, and that arguments that the resources would not be available based upon boilermaker membership in the 1990s proved to be wrong.

Figure 1. Boilermaker man-hours and new scrubbers and SCRs in service on coal EGUs – 1990-2011 [11]



[10] Installations of new gas-fired plants is not shown here, but did peak in 2001.
[11] Staudt, J., "Engineering and Economic Factors Affecting the Installation of Control Technologies– An Update", for US EPA Clean Air Markets Division, (Dec. 15, 2011) page 12, https://www.andovertechnology.com/wp-content/uploads/2020/07/9_2002_Update_12152011.pdf.

Figure 2. Construction boilermaker membership – 1998 - 2010[12]



14. EGU owners may also be complying with the stayed Good Neighbor Rule.[13] EPA estimated a substantial number of SCR and selective non-catalytic reduction (SNCR) optimizations for existing controls or the installation of state-of-the-art combustion controls to comply with the Good Neighbor Rule. The estimated cost of the rule for the EGU sector totaled $370 million to $460 million (2016$) annually, meaning the annualized cost of both the Good Neighbor Rule and the updated MATS rule totals well under $1 billion.[14] As will be demonstrated later, this is small relative to the

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[12] Staudt, J., "Engineering and Economic Factors Affecting the Installation of Control Technologies– An Update", for US EPA Clean Air Markets Division, at 13 (Dec. 15, 2011).
[13] 88 Fed. Reg. 36654 (June 5, 2023).
[14] Because the Good Neighbor rule has been stayed, compliance costs associated with that rule are unlikely to be incurred during this litigation. As discussed later in this declaration, EPA estimated an annualized cost of the updated MATS rule of $110 million. For the Good Neighbor Rule, see: *Regulatory Impact Analysis for the Final Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards,* EPA-452/R-23-001, March 2023, page 32.

annualized cost of past rules, suggesting a low impact on labor. EPA estimated 8 GW of SCR installations by the 2030 model run year (compared to over 25 GW of new SCR online in only 2003 alone), and 2,800 job-years for the 2030 model year inclusive of all construction trades for new pollution controls.[15] Comparing that to historical boilermaker employment data and assuming that as much as half of that value is boilermakers, this is small compared to past increases in boilermaker demand. EPA also forecast additional labor for new capacity. New capacity entails a much wider array of labor than air quality projects on conventional steam generation, and therefore a significantly lower portion of that labor would be for boilermakers. Furthermore, EPA's estimate includes a substantial amount of renewable generation as well as gas fired generation, both of which entail a smaller proportion of labor as boilermakers than for clean air retrofits on coal-fired steam EGUs (clearly, no boilermakers are required for renewable development). The total EPA estimate of construction-related jobs for the power sector for the Good Neighbor Rule, inclusive of all trades, was 15,400 job years in 2025 and 20,500 job-years in 2030.

15. I do not expect that the updated MATS rule will demand anything approaching the level of resources—labor or material—that these prior rules (NOx SIP Call, CAIR, or CSAPR) required. For this reason, and because of the industry's history of meeting the demands for air pollution control equipment, I am confident that the market will respond to and meet the demand for skilled labor and resources that may result from this rule and other power sector rules being implemented concurrently.

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[15] *Id.* at 272.

16. The prior paragraphs explain why I believe that the vendors, labor, and other resources necessary to meet the needs of industry to comply with the MATS revision will be available. The installation data presented in the prior paragraphs are irrefutable historical data. However, when the rules that motivated those air pollution control equipment installations were being developed, and even after they were finalized, the EGU industry argued that the resources were not available to allow industry to comply with the rules in the timeframe permitted or the rules would adversely impact reliability.[16] However, the market for equipment and labor responded to install the equipment, and the EGU industry complied with the rules without the reliability impacts they feared.[17] As a result, I am confident that industry will be able to meet the needs of this rule and reliability will not be impacted.

D. In the two-year period following promulgation of the rule only a small portion of the total cost will be incurred.

17. Air pollution control equipment installation occurs over a period of time that depends upon the specific equipment. Owners of EGUs will typically plan projects to be completed within a few months prior to the compliance date. For example, if the date when emissions rates of the rule must be achieved is July of 2027 (absent a one-year extension), equipment would likely be up and operating in the first or second quarter of 2027. Therefore, most of the

[16] *See* Brattle Group, *Supply Chain and Outage Analysis of MISO Coal Retrofits for MATS*, May 2012; Staudt, J., "Comments on the May 2012 Brattle Group Report", May 16, 2012, available at: https://www.andovertechnology.com/articles-archive.
[17] *See* Staudt, J., "Labor Availability for the Installation of Air Pollution Control Systems at Coal-Fired Power Plants", October 18, 2011, https://www.andovertechnology.com/articles-archive; Staudt, J., "White Paper - Availability of Resources for Clean Air Projects", October 10, 2010, available at: https://www.andovertechnology.com/articles-archive.

procurement and construction activities would be in the last two quarters of 2026 and perhaps into the first quarter of 2027, and these are the activities that entail the greatest demand for labor and materials. As a result, in the two-year period after the effective date of the rule – from July of 2024 to July of 2026 – most activities will be associated with engineering and planning, which are a very small portion of the total project cost.

E. Given an effective date of July 8, 2024, the majority of the Rule's costs will not be incurred until around late-2026.

18. I have personally been involved in the deployment of air pollution control systems at industrial sites. I worked for several years as a technology supplier. Later, in my consulting practice, I advised industrial clients who deployed air pollution control technologies as well as regulators. As such, I am very familiar with how these projects are executed and how costs are realized over the course of a project.

19. Air pollution control projects are conducted over a period of time where the greatest costs are realized in the latter portion of the project. Before any equipment can be ordered, it is necessary to perform sufficient engineering to ensure that equipment that will be ordered is specified correctly. For this reason, in the first months to a year after a project starts, most of the costs will be associated with engineering and permitting, which are generally a small portion of the total project cost. The largest cost items are equipment and installation which are in the final months of the project.

20. As noted elsewhere in this declaration, assuming a compliance date three years from the effective date of the rule, most of the expenditures for this rule will occur beginning in the third and fourth quarters of 2026. With a one-year delay, which may be permissible by permitting agencies in some cases, most expenses could be delayed into 2027. This is because most of

the costs for an air pollution control project are associated with procurement and installation of equipment, which are in the latter stages of a project. Prior to that point, most realized costs entail engineering and development of specifications, which are typically a small portion of the expenses associated with deploying this equipment.

F. The costs to comply are well below those of prior regulations.

21. In the RIA of the final rule, EPA forecast an annual cost of $110 million.[18] This is roughly consistent with ATP's 2023 report estimate of under $156 million[19] (both in 2019 dollars). EPA originally estimated that the 2012 MATS rule would cost $9.4 billion annually (2007$). In my 2015 declaration before the United States Court of Appeals for the District of Columbia Circuit[20] I determined in an *ex post* analysis that EPA overestimated the cost by $7.2 billion annually (2007$), resulting in an actual cost of about $2.2 billion annually. This is 20 times EPA's estimate for the new, updated MATS rule, not accounting for inflation, which would increase the difference.

22. Looking at other rules demonstrates that they had even higher costs compared to the updated MATS rule. According to the National Electric Energy Data System (NEEDS), from 1998 to 2004, 81 GW of coal or oil steam EGUs (virtually all of them coal) were retrofitted with SCR. These

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[18] Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards, EPA-452/R-11-011, December 2011, pages 3-14.
[19] $151 million is ATP's estimate for fPM. Annual costs for lignite units controlling Hg to 1.2 lb/TBtu were under $5 million.
[20] Staudt, J., Declaration Supporting Industry Respondent Intervenors to Govern Future Proceedings in *White Stallion Energy Ctr, LLC. v. EPA*, No. 12-1100 (D.C. Cir., Sept. 24, 2015), available at: www.andovertechnology.com/articles-archive.

were largely in response to the 1998 NOx SIP Call. Assuming a capital cost of roughly $250/kW, this results in an approximate one-time capital cost of $20 billion. Using a capital recovery factor of about 11%, the capital component of that cost alone is $2.2 billion annually. This also does not factor in 20 years of inflation which would raise that cost if represented in 2019$. Operating costs, such as reagent (ammonia), catalyst, and other costs will increase that cost even further. This also does not include the costs of other NOx control technologies used to comply with the NOx SIP Call, like SNCR and low NOx combustion technology.

23. According to NEEDS, during the years from 2007 to 2017, 103 GW of coal steam capacity was retrofitted with wet or dry scrubbers. This would largely be in response to the CAIR, CSAPR, and the Regional Haze Rule (RHR). Assuming an average capital cost of about $500/kW, this totals $52 billion in capital, or an annualized capital cost of about $5.7 billion using a capital recovery factor of 11%. Scrubbers also require the annual purchase of reagent (lime, limestone, etc.), significant energy use, substantial maintenance, and other costs. This also does not address the cost of other approaches for control with these rules, such as dry sorbent injection (DSI), SNCR and SCR for NOx control, and any costs associated with switching fuels. Simply put, the cost to comply with the updated MATS rule is far less than that of prior clean air programs that impacted many more units and entailed installation of more capital-intensive technologies than envisioned here.

G. EPA's *ex ante* cost estimates typically exceed actual compliance costs.

24. In my 2015 Declaration before the United States Court of Appeals for the District of Columbia Circuit,[21] I demonstrated that US EPA's *ex ante* estimate of the cost of complying with the 2012 MATS rule was much more than the actual compliance costs. This is rather typical for EPA's *ex ante* estimates.

   a. EPA's *ex ante* estimates are based upon technical options that are understood at the time of the rule. They do not account for technological innovation that results from the need to comply with the rule. By setting emissions limits in the form of emission rates or capture efficiencies, rather than mandating technology, EPA's rules motivate innovation to find less costly or more effective means of complying with the emission limit. In fact, the statutory language of Clean Air Act Section 112(d)(6) recognizes that methods for controlling emissions improve over time.

      i. *"[t]he Administrator shall review, and revise as necessary (taking into account developments in practices, processes, and control technologies), emission standards promulgated under this section no less often than every 8 years."*[22]

   The 2021[23] and 2022[24] ATP reports identified numerous technological developments that occurred after the 2012 MATS rule, including: advanced activated carbons, advanced reagent

[21] *Id.*
[22] 42 U.S.C. § 7412(d)(6).
[23] Staudt, J., *Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants, for* Center for Applied Environmental Law and Policy (CAELP), August 19, 2021.
[24] Staudt, J., *Opportunities for Reducing Acid Gas Emissions on Coal-Fired Power Plants*, for Center for Applied Environmental Law and Policy (CAELP), April 5, 2022.

injection systems, new means to control Hg in scrubbers, improved means to capture fPM, and other advances. These techniques helped to reduce the cost of complying with the rule versus EPA's *ex ant*e estimate of the cost of the 2012 MATS Rule.

b. Another example of a technical innovation that facilitated a lower cost approach is flue gas conditioning (FGC), which facilitated the widespread use of fuel switching to lower sulfur coals in order to comply with CAA Title IV Acid Rain provisions as well as later rules issued under CAA Section 110 (CAIR, CSAPR, etc.). Rather than continuing with the historical, higher sulfur coal, which was often proximal to the power plant, and using scrubbers to reduce SO_2 emissions, utilities changed fuels to lower sulfur western fuels. While changing fuels was understood as an option, there were some technical challenges due to the impact of fuel sulfur on the performance of the most common fPM control device – the ESP. Major changes to the ESP would be a significant cost impact that would make a change to lower sulfur fuels less economical. However, as noted in a 2023 ATP report,[25] 1990 and 1997 Air Markets Program Data demonstrates that, of the Phase I Title IV units, only 10.5% installed FGD, about 70.7% changed to lower sulfur fuels, and 18.8% continued with similar fuel sulfur levels as in 1990. Changing fuels was made possible through use of FGC, a technology that was not patented until 1993, three years after the

[25] J. Staudt, *History of Flexible Compliance with Science-Based and Technology-Based Stationary Source Air Pollution Regulations,* at 23-25, December 18, 2023, available at: www.andovertechnology.com/articles-archive.

passage of the 1990 Clean Air Act Amendments. Technical innovation therefore played a major role in the use of this lower cost approach to compliance. Use of lower sulfur fuel would also play a substantial role in compliance with other rules, such as CAIR, CSAPR and RHR.

c. Another effect is the willingness of industry to use technologies that were available at the time of the rule, but were not widely used, causing EPA and industry to consider these technologies too uncertain to include in an *ex ante* estimate of compliance costs. However, once there is a need to comply with a regulation, companies will be more open to trying the technology. An example is SNCR. As described in ATP's 2023 report,[26] although EPA stated that state NOx RACT emission limits were to be "consistent with the most effective level of combustion modification reasonably available for its individual affected sources," in several cases, coal-fired EGUs selected SNCR over combustion controls. SNCR had been available prior to this point, but there was very little experience on coal-fired EGUs at this point. Once faced with the need to reduce NOx emissions, utilities became more open to using SNCR technology.

H. EPA's regulation allows operators to run controls with a reasonable margin of safety to meet the fPM standard during normal operation.

25. Facility owners may choose to operate their equipment so that it can provide an emission rate that is sufficiently below the emission limit that the risk of

[26] *Id*. at 12-15.

exceeding the limit is acceptably low. This is often referred to as "compliance margin". As such, it impacts the number of facilities that are likely to opt for equipment upgrades and the cost. EPA anticipates that 33 units will require fPM emission control upgrades, and 22 lignite-fired units will make changes for Hg control.[27] This is consistent with the analysis performed by ATP in 2023.[28] Total annual costs estimated by EPA are also in a similar range as those determined by ATP. In its analysis, ATP utilized a compliance margin of 20% below the limit.

26. EPA looked at what adding a compliance margin of 20% would mean to its analysis.[29] Although EPA estimated that it would increase the number of facilities opting for significant fPM upgrades from 33 to 53 and increased annualized compliance costs to $147.7 million (nearly identical to what I determined for ATP in 2023), it would not increase the number of expected new baghouse installations, which is the highest cost option considered in the analysis.

27. EPA's treatment of fPM rates adds a significant degree of conservatism to their analysis that effectively results in compliance margin. In their analysis, EPA selected the lowest value of all quarterly 99th percentiles as the lowest achieved emission rate. This, in effect, is the highest rate for the lowest quarter. As a result, the typical rate is actually lower than what EPA used for the baseline emission rate. As shown in Figure 3, which plots the 99th percentile emission rate for the lowest quarter for affected units from highest

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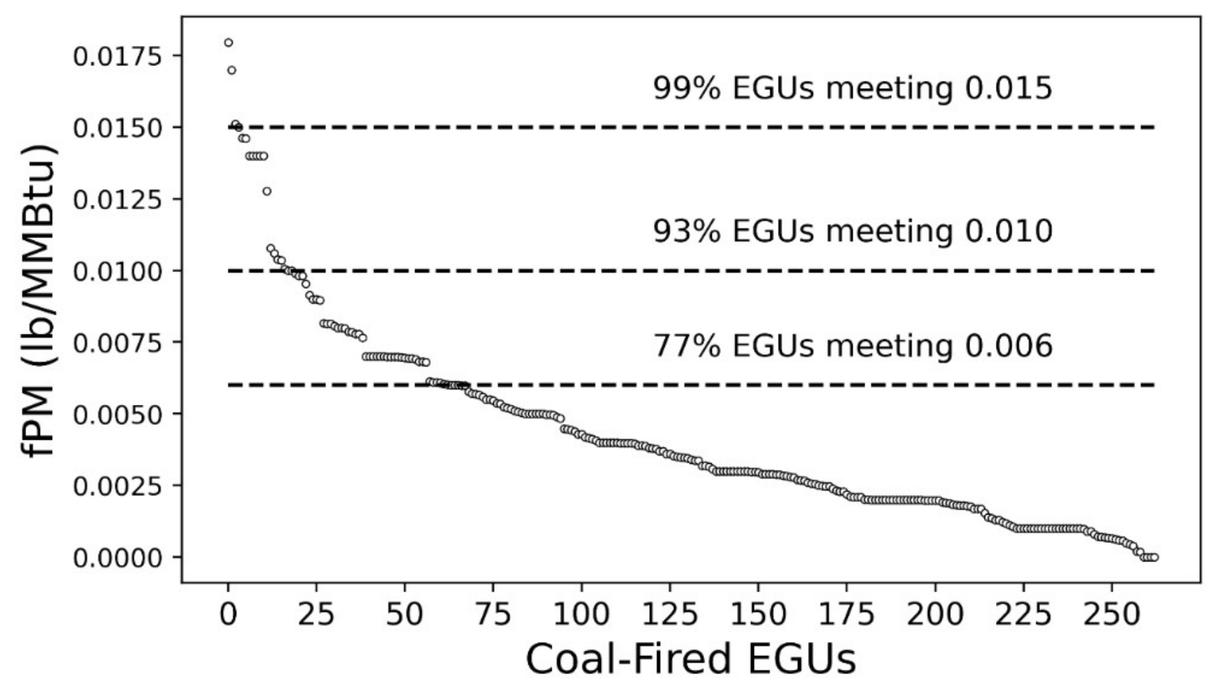
[27] Mercury and Air Toxics Standards (MATS) for Coal-Fired Power Plants Review of the 2020 Residual Risk and Technology Review (RTR), Final Rule, April 25, 2024.
[28] Staudt, J., *Assessment of Potential Revisions to the Mercury and Air Toxics Standards, for Center for Applied Environmental Law and Policy*, June 15, 2023.
[29] 89 Fed. Reg. 38521 (May 7, 2024).

to lowest fPM rate, even the highest fPM emission rates are at or below 0.010 lb/MMBtu for 93% of affected units. As will be demonstrated later in this declaration, the average fPM rate for a particular unit is typically well below the 99th percentile rate. As a result, the impact of using the 99th percentile of the lowest quarter as the baseline fPM rate provides a significant degree of conservatism.

Figure 3. fPM emission rates from coal-fired EGUs ranked, from left to right, from highest fPM emitting to lowest fPM emitting. Data is the 99th percentile of the lowest quarter rate. The dashed lines show the percentage of units that have previously demonstrated emission rates below 0.015, 0.010, and 0.006 lb/MMBtu.[30]



[30] Benish, S, Hutson, N., Eschmann, E., US EPA, 2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category (2024 Technical Memo), Docket ID. No: EPA-HQ-OAR-2018-0794, January 2024.

28. In estimating the cost of the rule, EPA did incorporate an additional cost of \$100,000 per year in additional effort to maintain emissions control equipment,[31] which is equivalent to a technician at half time (20 hours per week) at \$65/hour plus an additional 50 percent for materials. This is a reasonable effort for a technician to monitor the ESP performance and make typical repairs (repairing leaks in the casing, repairing failed insulators, etc.). This alone could be sufficient for many units to regularly achieve emissions well below the 99th percentile of the lowest quarter. Because of this, some units that have 99th percentile emission rates in the lowest quarter that are above the emissions rate limit of the updated MATS rule may be able to comply with the rule simply through added vigilance at a lower cost than EPA estimated for an ESP upgrade. This would reduce the actual cost of the rule from what EPA has estimated.

29. America's Power and Electric Generators MATS Coalition claimed that EPA stated that a memo regarding PM CEMS random error claimed compliance margin as high as 50% was appropriate.[32] This is incorrect. The memo in question[33] evaluated the random error contribution of the total tolerance percentage. The term "compliance margin" does not appear anywhere in the document.

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[31] *Id.* at 15.
[32] *America's Power & Electric Generators MATS Coalition v. EPA*, No. 24-1201, Petitioners' Motion for Stay Pending Judicial Review at 19 (D.C. Cir., July 8, 2024).
[33] U.S. Environmental Protection Agency, PM CEMS Random Error Contribution by Emission Limit, March 22, 2023, Docket ID No. EPA-HQ-OAR-2018-0794.

I. The 30-day averaging period is sufficient to address any spikes or variability in emissions.

30. ESPs occasionally have insulators that fail, electrodes that fail, or duct or casing leaks. All of these periodic issues impact ESP performance, and they can be readily addressed. Similarly, baghouses can have filter bags that develop leaks that can be readily addressed. Spikes and variability that increase fPM rate, therefore, may occur, and these may need to be offset by lower fPM rates to compensate for the spike and maintain compliance when averaging over the 30-day period. With a PM CEMS it is possible to quickly identify the issue with the fPM control equipment and then promptly correct it.

J. PM CEMS enable prompt identification of a performance-impacting malfunction that can be corrected

31. PM CEMS provide a continuous data stream of fPM emissions. If an equipment malfunction occurs, PM CEMS will permit the facility owner to immediately see the impact of the problem and promptly take corrective action. Therefore, the PM CEMS can help avoid exceedances and enable plants to achieve lower emissions rates overall, even with the same pollution control equipment. This has been demonstrated with actual data that compares 30-day rolling average to daily average data and data suggestive of corrective action.[34]

[34] See Appendix in Staudt, J., *Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants, for* Center for Applied Environmental Law and Policy (CAELP), August 19, 2021.

32. Comments on the proposed rule,[35] a portion of which were also incorporated into a Motion to Stay that is discussed later, included some critiques about variability in emissions rates. But, these comments also demonstrate how corrective measures are taken. A graph in these comments[36] that presented the quarterly mean and 99th percentile fPM emission rates at Coronado Generating Station shows some variability from quarter to quarter. Coronado's fPM emissions rate in this data shows levels greater than the median in Figure 3, which is well below 0.0050 lb/MMBtu. In the case of Coronado, there were peaks in 18Q4 and 21Q2. However, this graph (shown in Figure 4 with additional notation) shows two sawtooth patterns – some that span over two years. I reviewed fuel purchase and use data in Form 923[37] and operating data (generation) for these periods, and I did not see anything in the fuel use history or operating history that would explain the variations shown. Therefore, this was likely the result of addressing fPM equipment effects, such as failed insulators or electrodes. Coronado is equipped with ESPs and wet FGD.

a. The figure and my analysis make it clear that:

- The mean fPM rate is typically well below the 99th percentile rate, as noted earlier in my declaration.
- These patterns of variability are not seasonal, as they span more than a year.

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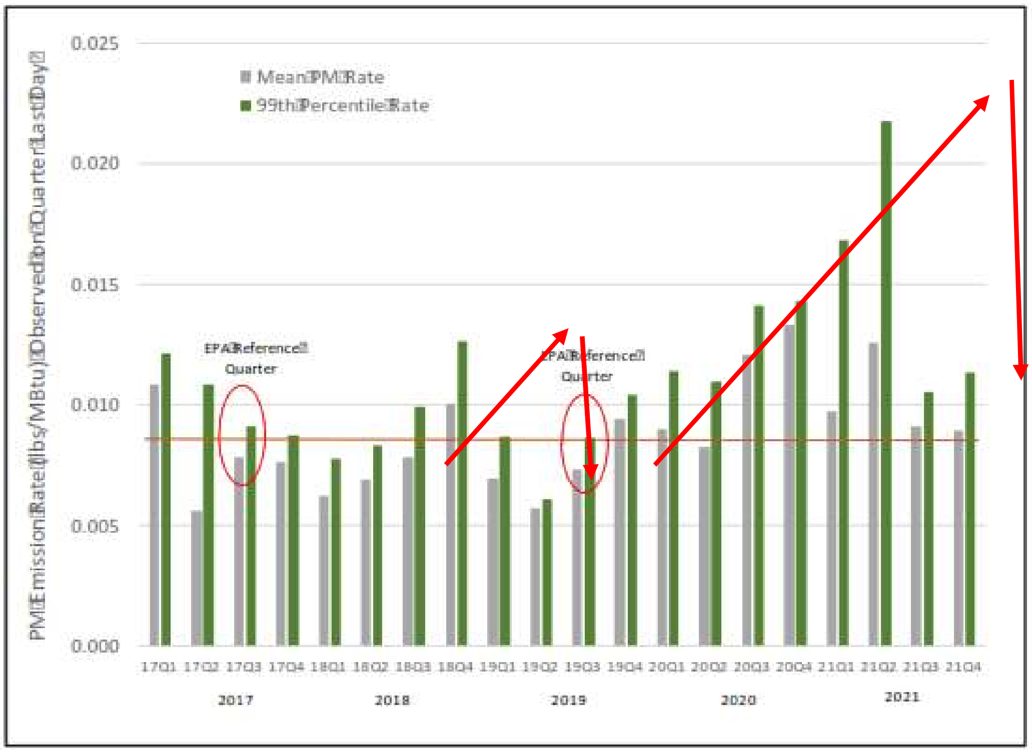
[35] America's Power Comments on EPA's Proposal to Revise the Mercury and Air Toxics Standards: Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology, by Cichanowicz, et. al. June 19, 2023.
[36] *Id.* at 10 (pdf page 20).
[37] Energy Information Administration (EIA) Form 923 includes reported monthly fuel use, fuel characteristics, generation, fuel purchase and other data.

- There is nothing in the operating history or fuel used that explains this.
- For Coronado, these patterns suggest that some intervention may have been made early in quarters 19Q1 and 21Q3 that caused a significant drop in PM emission rates.
- Each of these apparent interventions brought the mean fPM rate below 0.010 lb/MMBtu.[38]

Figure 4. Coronado Generating Station, 20 operating quarters[39]



b. This data therefore suggests that periodic intervention, which can be facilitated by PM CEMS (which will enable even quicker intervention), can improve fPM emission rates. The other

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[38] Notably, from 17Q2 to 20Q2 the average quarterly fPM emission rate remained at or below 0.010 lb/MMBtu.

[39] *Id*. at 10 (with additional notation).

examples in Appendix B of the comments[40] also show trends suggesting that additional vigilance in monitoring PM control device performance and occasional intervention will result in more consistent and lower fPM emission rates.

33. EPA examined a large number of facilities in a technical memorandum and looked at variability in particular.[41] EPA also looked at additional quarters of data, examining 30-day average emissions for some units. EPA determined that, while the lowest achieved rate was not representative of the average emission rate over longer periods, "the lowest achieved fPM rate remains effective for identifying EGUs that have historically achieved lower fPM rates, despite not being required to do so and without additional capital investments."[42] Therefore, some of these units that had average emission rates above the limit could potentially meet the limit with existing equipment on a consistent basis with additional effort to maintain and operate their fPM equipment for more consistently low emissions, particularly with PM CEMS alerting operators to problems with PM controls or spikes in PM emissions that could be promptly corrected.

34. From a CEMS performance perspective, there is substantial operating experience with PM CEMS demonstrating that compliance with a 30-day rolling average fPM rate of 0.010 lb/MMBtu is regularly measured. Figure

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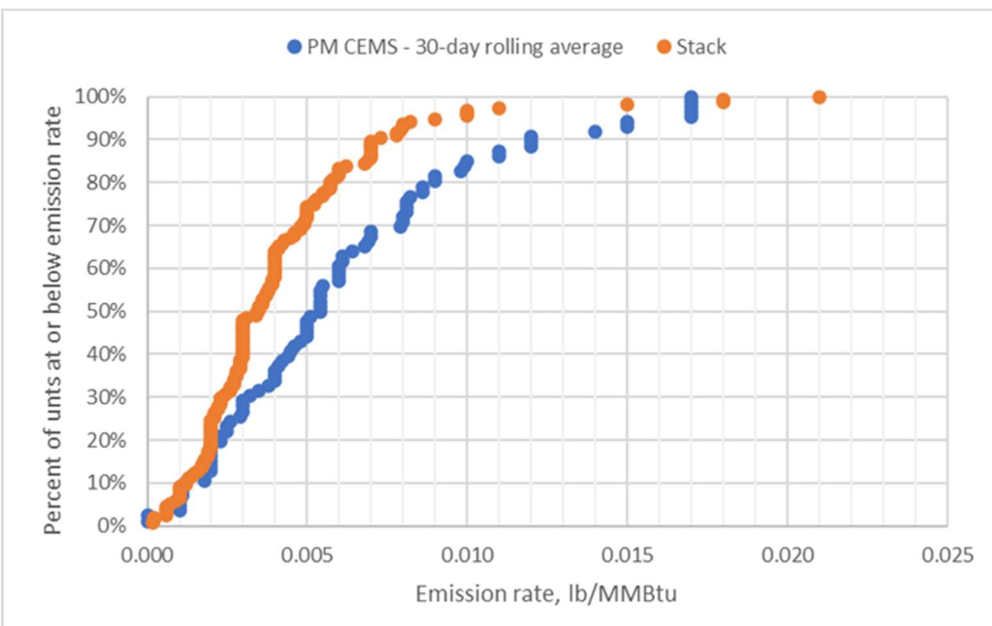
[40] America's Power Comments on EPA's Proposal to Revise the Mercury and Air Toxics Standards: Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology.

[41] Benish, S, Hutson, N., Eschmann, E., US EPA, 2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category (2024 Technical Memo), Docket ID. No: EPA-HQ-OAR-2018-0794, January 2024.

[42] *Id.* at 8.

5 is from ATP's 2023 report[43] that assessed the proposed MATS rule. This shows the 99th percentile of fPM emissions rates for the lowest quarter. As shown, about 85% of the units included in that data equipped with PM CEMS reported 30-day averages at or below 0.010 lb/MMBtu. In fact, nearly 50% of all PM CEMS equipped units reported 30-day averages at or below half of that rate. Since these are the highest emissions of the lowest quarter, the actual averages are less than this. As a result, the data indicates that the majority of units equipped with PM CEMS are already well under the new emission limit, and apparently are not having difficulty meeting the emission limit or measuring emissions at that level.

Figure 5. Percent of units with a measurement method (PM CEMS or stack sampling) with baseline (99th percentile of lowest quarter) fPM emissions at or below a particular emission rate[44]



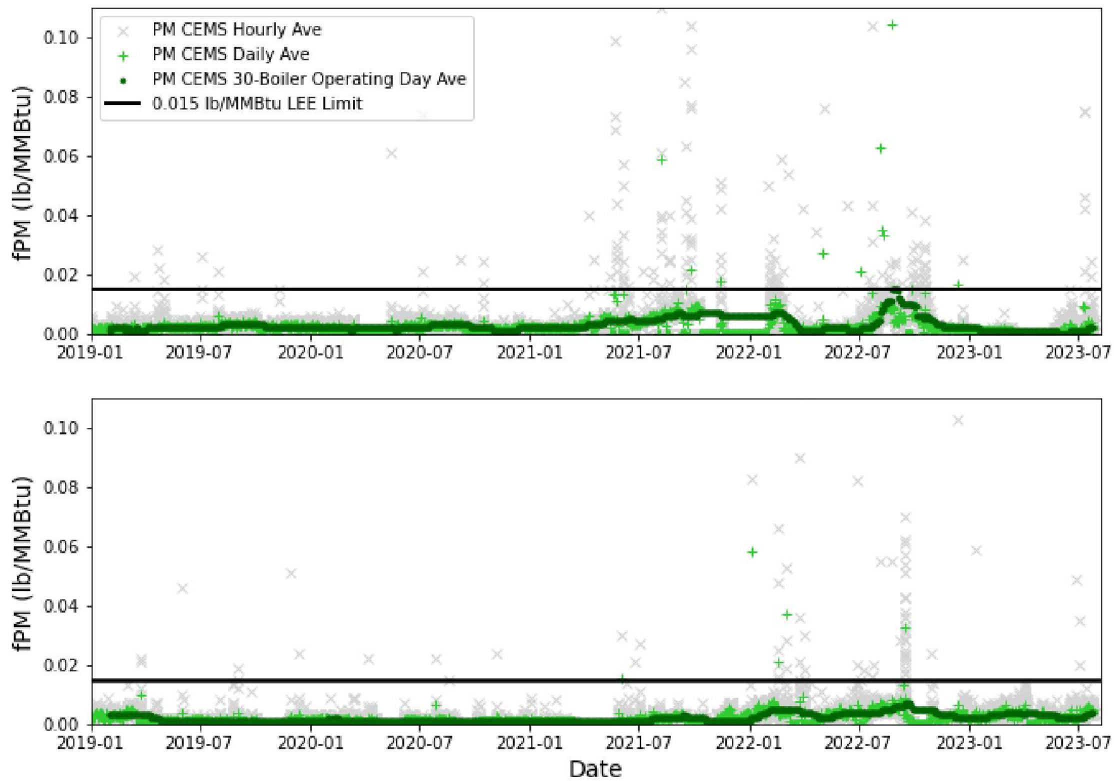
[43] Staudt, J., *Assessment of Potential Revisions to the Mercury and Air Toxics Standards, for Center for Applied Environmental Law and Policy*, June 15, 2023, available at: www.andovertechnology.com/articles-archive.

[44] Developed from Appendix C data from 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category, proposed rule.

35. EPA provided an analysis demonstrating the transparency benefits of using PM CEMS.[45] This analysis includes data that also illustrates the impact of averaging over a 30-day limit. EPA examined a facility that qualified as a low emitting EGU (LEE). It had fPM CEMS installed due to a consent decree, even though it could demonstrate compliance with MATS through intermittent stack testing every three years, and could comply with an emission limit of 0.015 lb/MMBtu. The data presented demonstrates the effects of averaging. Figure 6 shows the fPM CEMS emissions data for two units between 2019 and mid-2023. For Unit 1A the hourly value ranged from near zero to as high as 1.33 lb/MMBtu, with average and median values of 0.0028 and 0.0020 lb/MMBtu, respectively. The figure shows the daily average (light green) and the 30-day average (dark green). It is clear that the 30-day average is typically far below the LEE limit of 0.0150 lb/MMBtu and rarely gets close to the limit, although several hourly emission rates are well above the limit and some daily rates are well above the limit. Similarly, for Unit 1B, the same effect is shown, while generally that unit has even lower emission rates that are all below the MATS update emission rate of 0.010 lb/MMBtu on a 30-day average. So, it is clear from this data that averaging over a 30-day period has a profound impact in averaging out even very high shorter-term emissions rates.

[45] Benish, S, Hutson, N., Eschmann, E., US EPA, 2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category (2024 Technical Memo), Docket ID. No: EPA-HQ-OAR-2018-0794, January 2024, page 42.

Figure 6. PM CEMS data for Units 1A (top) and 1B (bottom) between 2019 and mid 2023.[46]



K. EPA's estimated cost of a PM CEMS is reasonable

36. In their Motion to Stay the Rule, the Midwest Ozone Group claimed that EPA underestimated the cost of PM CEMS.[47] EPA estimated an annual cost of $72,000 for the cost of operating a PM CEMS. This includes annualized capital and other annual costs. One source[48] stated that the initial cost was $120,000 per year with annual costs $40,000 per year. Another source[49]

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[46] *Id.* at 44.
[47] *Midwest Ozone Group v. EPA*, No. 24-1119, Motion for Stay, at 6 (D.C. Cir., July 8, 2024).
[48] PS-11 (PM CEMS), Multi-metals CEMS, Multi-metals Fence Line Monitoring, & CEMS Cost Model; https://www3.epa.gov/ttn/emc/meetnw/2007/cemsupd.pdf
[49]Stuart, Derek, "PM-CEMS and PM-CPMS for Dry Stacks", https://www.mcilvainecompany.com/Decision_Tree/2015%20WEBINARS/April%202015/Derek%20Stuart,%20Ametek%20-%204-16-15.jpg.pdf.

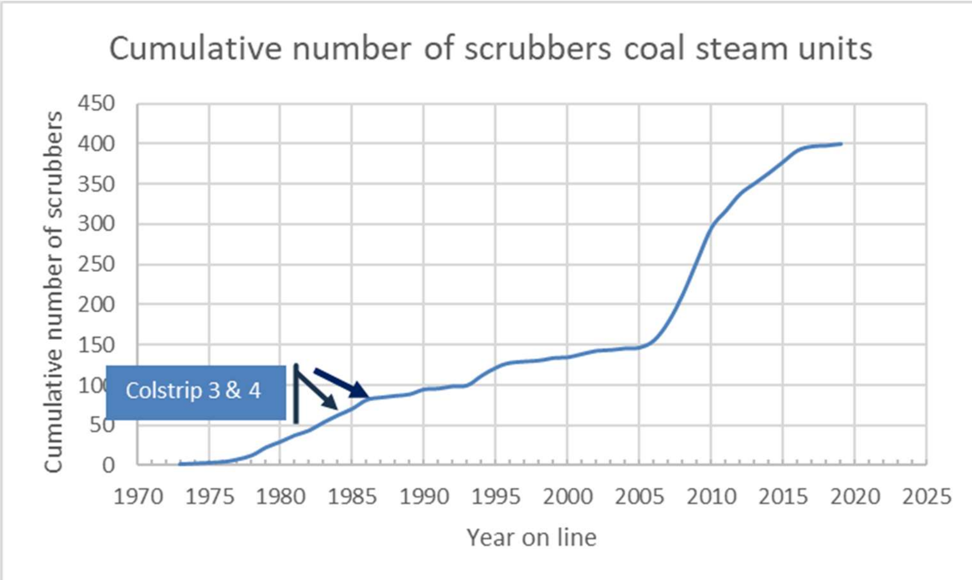
indicated the monitor would cost about $40,000, initial testing $30,000, plus installation – which would be close to the other estimate of $120,000 initial cost. As a result, an annualized cost of $72,000 for annual cost plus annualized capital would be very reasonable.

L. Colstrip Power Plant has no dedicated PM control device but can be retrofit to comply with the MATS Update Rule.

37. Talen Montana, LLC and Northwestern Corporation jointly submitted a motion to stay the Update Rule. Colstrip Units 3 & 4 are the sole coal-fired EGUs in the United States with no dedicated PM control device such as an ESP or baghouse. To control both fPM and SO_2, these units instead use venturi scrubbers[50] that were put in place in the mid-1980s (1984 and 1986). Therefore, they are currently about 40 years old, and are among the oldest scrubbers on coal-fired EGUs, as demonstrated in Figure 7. As shown in Figure 7, of the scrubbers on the nearly 400 coal-fired EGUs, over 60% were built in the last 20 years. The Colstrip scrubbers are among the oldest 20% of all scrubbers, and virtually no scrubbers are more than 10 years older than those at Colstrip. Notably, each of the other nearly 400 scrubbed EGUs is installed with a dedicated fPM control device. So, for about 40 years, while other companies installed and operated dedicated fPM control devices, Colstrip has operated with a venturi scrubber.

[50] Venturi scrubbers are a form of wet scrubber that combines both fPM and SO_2 control.

Figure 7. *Cumulative number of active coal steam units with scrubbers*[51]



38. Moreover, venturi scrubbers, such as those at Colstrip, have generally been abandoned as obsolete technology. For example, the Dave Johnston plant in Wyoming replaced its 1972 venturi scrubber with a pair of dry scrubbers and baghouses in 2010 and 2012, 40 years after that venturi scrubber was installed.[52]

39. In their motion to stay, Talen and NorthWestern mention EPA's citation of a report that I prepared (page 9-10) that described the fact that fabric filter material has improved since 2012. This is a fundamental improvement to the technology, as the filter media is what actually does the filtering. Improved fabrics enable significant improvements in performance and are regarded as technology developments. As noted in my ATP 2021 report

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[51] Developed from active units in NEEDS v6.
[52] See NEEDS v.6 and 2012 EIA Form 860.

and in a memo to EPA by Sargent & Lundy,[53] since the 2012 MATS rule, there have been improvements in filter bag materials that make fabrics more durable, easy to clean, and this will translate into lower fPM emissions because fabric failure or other means of leakage are the most common mechanisms for increased emissions. So, improved fabrics certainly constitute advancements, innovation and evolution of the fabric filter technology, and this is the technology that was identified by Talen Montana[54] for use at Colstrip.

1. fPM equipment can be retrofit at Colstrip Power Plant

40. Talen Montana's comments on the proposed Update Rule[55] include a memo from Burns and McDonnell (B&M) that confirms that a fabric filter, dry ESP, or wet ESP could be retrofit after the venturi scrubber. It also examines installation of a dry ESP or fabric filter prior to the venturi scrubber.

41. Attachment A of Exhibit 1 of Talen Montana and NorthWestern's joint motion to stay is a report from B&M that provides a cost estimate for a fabric filter of about $356 million. The fabric filter would be installed after reheat and prior to the chimney.

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[53] *See* Staudt, J., *Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants, for* Center for Applied Environmental Law and Policy at 26-28 (CAELP), August 19, 2021; PM Incremental Improvement Memo, Sargent & Lundy (2023); EPA Memo "2023 Technology Review for the Coal- and Oil-Fired EGU Source Category" (Docket ID. No: EPA-HQ-OAR-2018-0794).

[54] See Attachment A to Exhibit 1 of *Talen Montana, LLC & NorthWestern Corp. v. EPA*, No. 24-1190 and 24-1217, Joint Motion for Stay (D.C. Cir., June 27, 2024).

[55] Comments of Talen Montana, LLC on the Proposal on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, Docket ID: EPA-HQ-OAR-2018-0794.

42. It is apparent that fPM control technology can be retrofit onto the Colstrip plant to bring it into compliance with the MATS Update Rule. The difference between EPA's estimate and that of B&M is only about 16%.[56] Given the typical accuracy range of Class 4 or 5 estimates, this is a small difference. The consistency in the cost estimates between B&M and EPA confirms that installation of retrofit fPM controls at Colstrip is possible at a reasonable cost. Colstrip does not have an announced retirement date.[57] Therefore, a shorter amortization period than a typical 20-year amortization is not justified in an economic analysis.[58]

2. The technology can be installed in time to comply with the rule, and any costs incurred during litigation would be small.

43. Prior discussion in this declaration addresses the timing to install controls. Fabric filters can be installed in two years from engineering through commissioning. Most costs are incurred in the final year or months, with prior costs for engineering representing a small portion of the total project cost. Therefore, with a three-year compliance period, the higher cost procurement and installation efforts would be in the final year. With an additional year, even the engineering could be delayed until after the

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[56] Attachment 1 to: Benish, S, Hutson, N., Eschmann, E., US EPA, 2024 Update to the 2023 Proposed Technology Review for the Coal- and Oil-Fired EGU Source Category (2024 Technical Memo), Docket ID. No: EPA-HQ-OAR-2018-0794, January 2024. EPA's cost was $204/kW and $205/kW, respectively for each of the two 740 MW units, which results in a cost of $303 million.

[57] *Talen Montana, LLC & NorthWestern Corp. v. EPA*, No. 24-1190 and 24-1217, Joint Motion for Stay at 14 (D.C. Cir., June 27, 2024).

[58] *Id.* at 11. Talen Montana and NorthWestern argue that the GHG Rule will compel retirement in 2031. This is incorrect. The GHG Rule offers options for compliance that a company may choose to use, or they may alternatively choose to retire.

expected litigation period and still allow a plant to meet its compliance deadline.

RESPONSE TO NORTH DAKOTA AND WEST VIRGINIA MOTION TO STAY

44. North Dakota and West Virginia submitted a Motion to Stay.[59] The Motion to Stay includes several declarations and exhibits. Among these declarations are those of Sonja Nowakowski, Jason Bohrer, Gavin McCollam, Robert McLennan, and Claire Vigesaa. The motion to stay also included reports prepared by Sargent & Lundy on the Milton R. Young (MRY) plant (Attachments A and E)[60] and Attachment B, hereafter referred to as the Cichanowicz report.[61] Attachment D is a report by Sjostrom. Issues discussed in these declarations include arguments questioning the ability to control lignite units' Hg emissions to 1.2 lb/TBtu and arguments questioning the ability to control fPM emissions to under 0.010 lb/MMBtu and the costs to control fPM emissions.[62]

A. Properties of lignite coal do not preclude control of Hg emissions to 1.2 lb/TBtu

45. Declarants in the Motion to Stay argued that the properties of lignite coal preclude the ability to control to 1.2 lb/TBtu. They argued that lignite coal properties were too variable and otherwise too challenging for controlling to

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[59] *North Dakota v. EPA*, No. 24-1119, Amended Motion for Stay (D.C. Cir., June 7, 2024).
[60] *See* Attachments A and E to Exhibit 9, Declaration of Robert McLennan, at 167 and 249 of *North Dakota v. EPA*, No. 24-1119, Amended Motion for Stay (D.C. Cir., June 7, 2024).
[61] Attachment B, J. Cichanowicz et al., Technical Comments on National Standards for Hazardous Air Pollutants: Coal- and Oil-fired Steam Generating Units Review of Residual Risk and Technology (June 19, 2023) to Exhibit 9, Declaration of Robert McLennan, at 184 of *North Dakota v. EPA*, No. 24-1119, Amended Motion for Stay (D.C. Cir., June 7, 2024) (hereinafter "Cichanowicz Report").
[62] Paragraphs 25 through 29 of this declaration address compliance margin for fPM emission control.

1.2 lb/TBtu. They raised questions about variable Hg content, sulfur content and alkalinity. Lignite coal does generally have higher Hg content than other coals, but as will be shown, some bituminous coals have higher Hg content than most lignite coals and that Hg is even more variable for some bituminous coals.

1. Impacts of mercury, sulfur, alkalinity, and configuration

Mercury variability

46. The Cichanowicz report examines Hg variability by examining data from mines for Hg, alkalinity and sulfur data. The report shows mine data. Mine borehole data is less useful than using data regarding the coal that is actually used in the plant, which is available in EIA Form 923 Fuel Receipts and Cost.

47. Where EIA Form 923 data was shown in the Cichanowicz report, it was combined for many different mines and plants. Figure 6-8 of the Cichanowicz report shows Hg and sulfur data for various plants firing lignite coals. However, since this includes data from 60 lignite mines and 40 PRB mines, it is not useful for determining the situation at any given plant. Lignite coal plants are mine-mouth, and therefore only receive coal from the local mine. As demonstrated in the following paragraphs, for any given plant the variation is quite small.

48. MRY mercury data in Attachment A stated that it had an average of 8.41 lb/TBtu and a maximum of 17.42 lb/TBtu.[63] Standard deviation was not provided. On the other hand, a calculation of average and standard deviation

[63] Exhibit 9, Declaration of Robert McLennan, Attachment A, Minnkota Power Coop., Mercury Testing Results for the MATS Residual Risk and Technology Review (May 22, 2023), at 6, tbl. 2-4, in *North Dakota v. EPA*, No. 24-1119, Amended Motion for Stay (D.C. Cir., June 7, 2024).

of the data provided in Table 2-5 of Attachment A resulted in an average of 10.3 lb/TBtu and a standard deviation of 3.28 lb/TBtu.[64] Both MRY units are equipped with a cold-side ESP and a wet scrubber.

49. EIA Form 923 Hg data for lignite-fired plants and the data for one bituminous coal mine (Hoover Job, which is used at the Conemaugh plant in Pennsylvania) for 2020 through 2023 were evaluated. Not all plants submit Hg content data for EIA Form 923. The average and population standard deviation are shown in Figure 8 along with the MRY average and standard deviation of the data in Table 2-5 of Attachment A.

50. The figure demonstrates that for each of the lignite-fired facilities where Hg data was available, the standard deviation is well below the average Hg content, indicating little variation. The MRY plant coal Hg standard deviation, as a percentage of the average, was the highest of the lignite units, at around 32%. It was also a relatively low Hg content for the lignite units, at about 10 lb/TBtu. The next highest standard deviation was Coyote plant at 22%, but, again with an average Hg concentration of under 10 lb/TBtu. For the bituminous mine, Hoover Job mine in Pennsylvania, the standard deviation is well above half of the average, indicating significant variation and *much higher than any of the lignite units*. And the Hoover Job mine has an average Hg content over 40 lb/TBtu. Yet, as a bituminous fired unit, per the 2012 MATS rule, the Conemaugh plant has been required to maintain emissions below 1.2 lb/TBtu. In fact, the Hg reported emissions have been consistently below 1.2 lb/TBtu for both Conemaugh units, as demonstrated

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[64] This was calculated by using the average and stdevp function in Microsoft Excel for the data in the table.

in Figure 9, despite having coal with higher Hg content than many lignite plants.

Figure 8. Average mercury content (lb/TBtu) and population standard deviation[65]

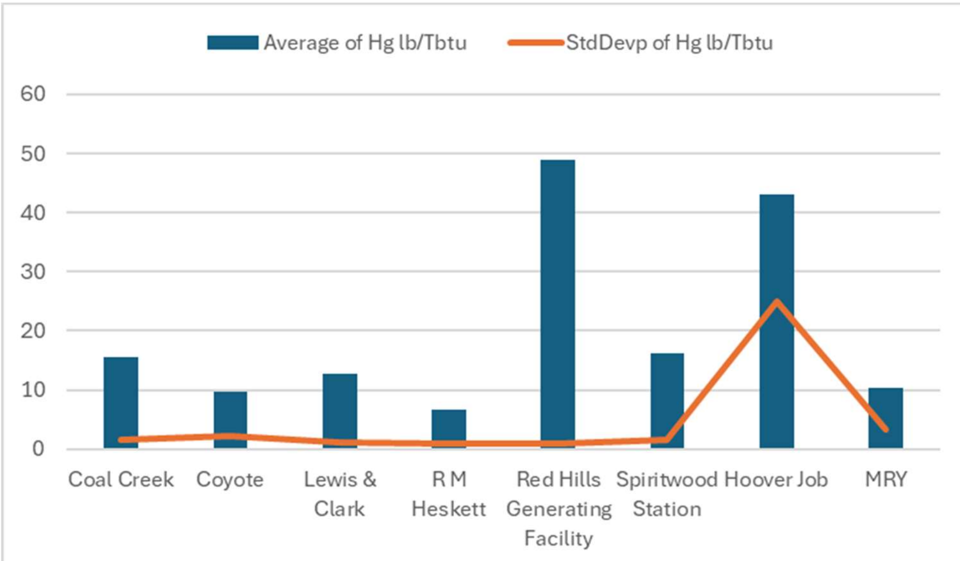
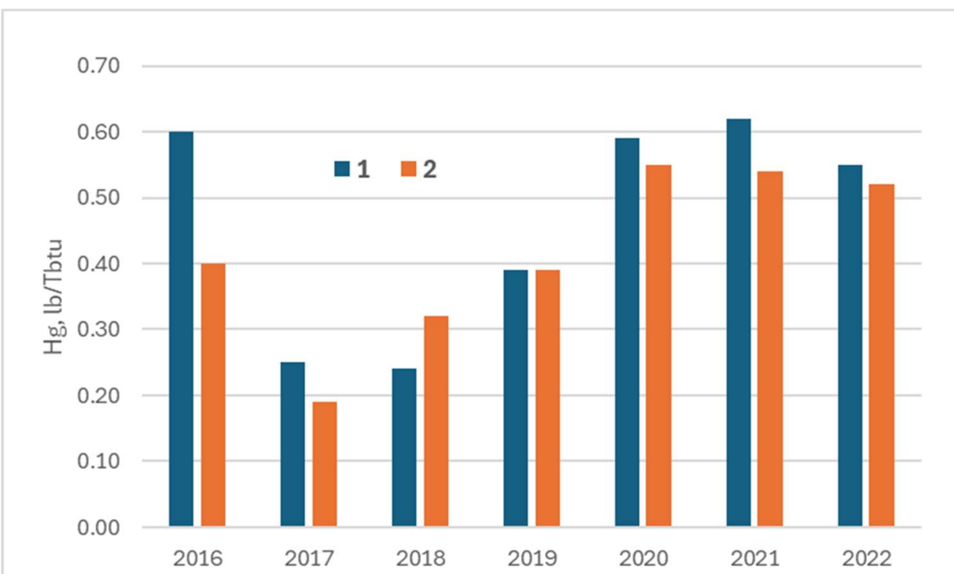


Figure 9. Conemaugh Units 1 & 2 reported Hg emissions (lb/TBtu)[66]



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[65] Calculated from 2020 and 2021 EIA Form 923 Fuel Receipts and Cost. Reported Hg content in ppm is multiplied by 2000 and divided by heat content in MMBtu per ton of coal.
[66] Data from EIA Form 923.

Impact of sulfur and alkalinity

51. The principal concern with sulfur is SO_3, which can adversely impact Hg capture by ACI. The majority of coal sulfur is oxidized to SO_2 and a smaller portion is oxidized to SO_3. SO_3 formation is impacted by the coal sulfur and factors such as whether an SCR is present. SCR will oxidize sulfur and result in higher SO_3 levels. Sulfur data, and therefore inferred SO_2 emissions, is more available than Hg data. As shown in Figure 10, standard deviation of inferred SO_2[67] in the exhaust gas is small for lignite coals. This provides some insight to the SO_3 content of the flue gas. Also, the Hoover Job mine, like many other bituminous coals, results in significantly higher SO_2 content (and, presumably higher SO_3 content) than most of the lignite coals. The SO_2 levels for the Hoover Job mine are typical for high-sulfur bituminous coals, such as Illinois Basin coals or Northern Appalachian coals. Most Central Appalachian coals result in higher SO_2 levels (and therefore higher SO_3 levels) than lignite coals. These figures clearly demonstrate that the Hg and SO_2 content resulting from lignite coals are no more problematic than some bituminous coals that have long been subject to the 1.2 lb/TBtu limit. Moreover, the majority of high-sulfur bituminous coal capacity has SCR systems for NOx control, which means that SO_3 oxidation is generally a greater concern for those bituminous units than for lignite units. Only one lignite plant (Oak Grove in Texas) is equipped with SCR. Therefore, the issue of SO_3 is no more challenging and likely less challenging for lignite units than for eastern bituminous units equipped with SCR.

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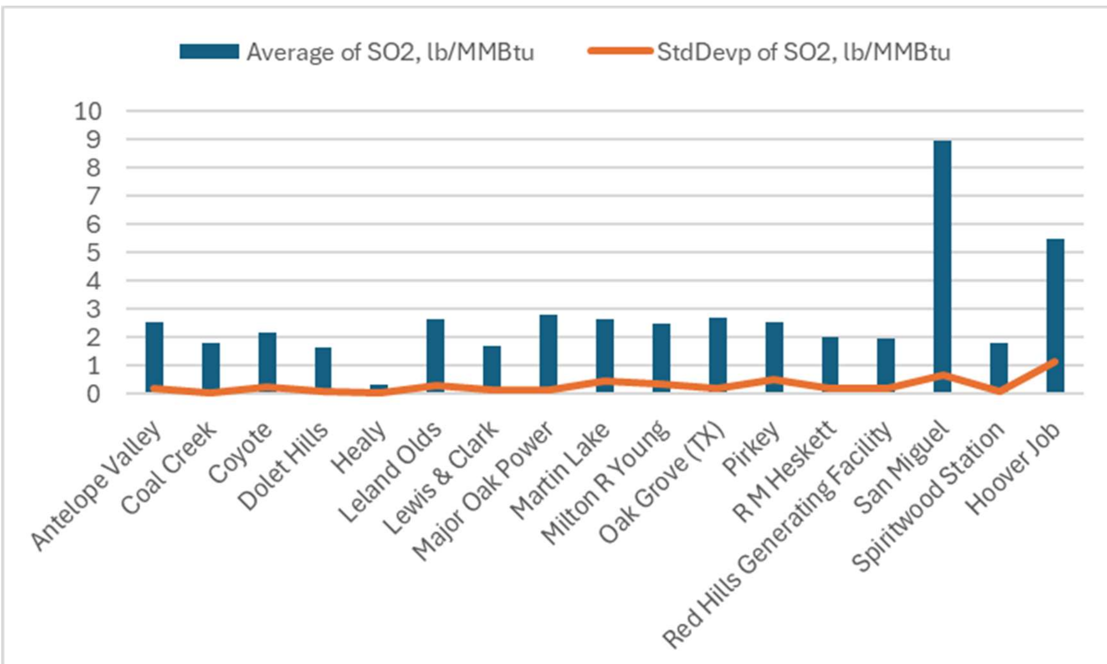
[67] SO_2 was inferred by multiplying the reported percent sulfur in EIA Form 923 by 40 and dividing by the heat content in MMBtu per ton of coal.

52. Alkalinity is a factor because it can mitigate SO_3. Alkalinity can vary widely for bituminous coals, with some Northern Appalachian coals that have high sulfur also having low calcium content, and generally lower alkalinity than western coals. It is also possible to add alkalinity, if needed. This has been done on bituminous coal boilers in order to address SO_3.[68] And, this does not factor in the availability of sulfur tolerant activated carbons that are discussed more in the next paragraph.

Figure 10. Average inferred SO_2 (lb/MMBtu) and population standard deviation[69]



53. SO_3 is not the issue that it once was because activated carbon is now available that can address high concentrations of SO_3 without relying upon

[68] Power Magazine, "Dry Injection of Trona for SO3 Control", (May 1, 2010).
[69] Calculated from 2020 and 2021 EIA Form 923 Fuel Receipts and Cost.

alkalinity to address SO_3.[70] These carbons were not available at the time the 2012 MATS rule was developed. These carbons were mostly developed to address bituminous coal units in order to avoid addition of alkalinity, especially unscrubbed units that had to capture all of the Hg in the ESP.

54. The Cichanowicz report suggested that sulfur and alkalinity content were highly variable and had a major impact on Hg capture. But, for affected lignite facilities, sulfur and alkalinity should not be a major factor. As shown, SO_2 is not highly variable for any given lignite-fired unit, and SO_2 (and presumably, SO_3) is generally lower for lignite units than bituminous units. Sulfur and alkalinity are most important when ACI is heavily relied upon for Hg capture for units with ESPs and no other equipment (such as a scrubber) is available to capture Hg. As noted below, no affected lignite unit has this ESP-only configuration. In fact, Attachment D to the Motion to Stay is a paper by Sjostrom, et. al. It discusses the general state of Hg capture at the time and compares the ability to control Hg for different coals. On the second page of the paper it states: "ACI at sites firing western fuels, such as PRB coals or lignite (Lig.) coals, results in higher mercury removal than sites firing bituminous (Bit.) coals." So, this clearly suggests that bituminous coals are generally more difficult than lignite coals for controlling Hg emissions when using ACI.

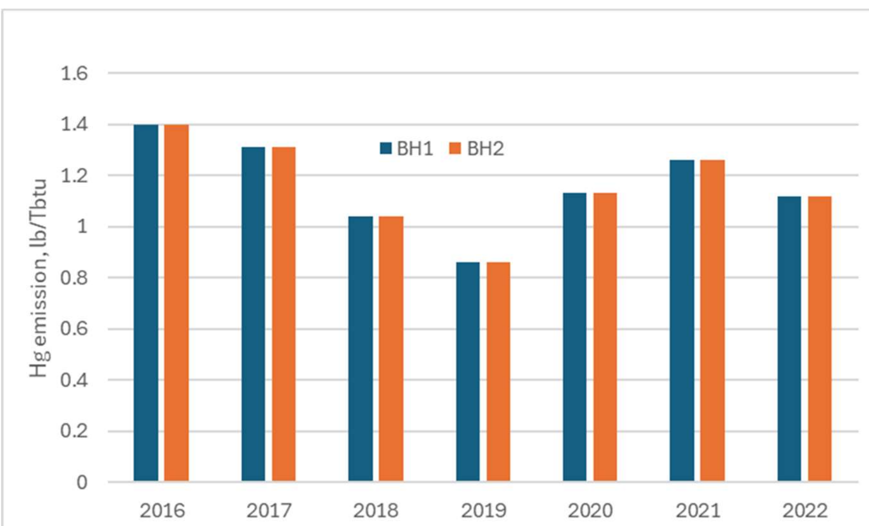
[70] *See* Google Patents, Calgon Carbon, https://patents.google.com/patent/EP2956230B1/en?assignee=calgon+carbon&oq=calgon+carbon (describing a carbon offered by Calgon Carbon that is used); Google Patents, ADA Carbon Solutions, https://patents.google.com/patent/US20140191157A1/en?assignee=ada+carbon+solutions&oq=ada+carbon+solutions&page=1 (Arq: FastPAC Premium 80). *See also* ATP 2021 at 48-51.

Configuration

55. Importantly, none of the lignite facilities are the most difficult configuration to control for Hg – unscrubbed, pulverized coal (or cyclone) units with only an ESP for fPM control. There are numerous[71] bituminous units with this configuration, and they have been controlled to under 1.2 lb/TBtu for years. No lignite units have this, most challenging, configuration.

56. The significance of having a favorable configuration is illustrated by the lignite-fired Red Hills Generating facility. EIA Form 923 reported Hg emissions for Red Hills Generating facility for 2016 through 2022 showed rates under 1.2 lb/TBtu in the years 2018, 2019, 2020, and 2022, as shown in Figure 11. A database of coal-fired power plants developed by Natural Resources Defense Council[72] provided roughly consistent data.

Figure 11. Hg emission rates for Red Hills Generating[73]



[71] NEEDS v6 showed 27 unscrubbed, operating bituminous units equipped with cold-side ESPs.
[72] A database of coal-fired power plants developed by Natural Resources Defense Council indicated 2020 average emission rate at Red Hills Generating facility averaged 1.041 lb/TBtu for unit 1 and 1.15 lb/TBtu for unit 2. NRDC, Coal-Fired Power Plant Hazardous Air Pollution Emissions and Pollution Control Data, https://www.nrdc.org/resources/coal-fired-power-plant-hazardous-air-pollution-emissions-and-pollution-control-data.
[73] Data from EIA Form 923.

57. This is significant because this is under the 1.2 lb/TBtu level and Red Hills has the *highest Hg content* coal of the lignite units for which EIA Form 923 Hg data was available. The Red Hills lignite-fired facility in Mississippi is a circulating fluid bed facility with a fabric filter, which is a configuration that responds very well to activated carbon for Hg control because of the high free lime and the high capture possible with a fabric filter. In 2020 these units were operating with "Refined Coal", which in this case is treated lignite coal designed to mitigate Hg, SO_2 and NOx emissions. According to the NRDC database, two other lignite units achieved under 2.0 lb/TBtu that year, Dolet Hills and Lewis and Clark plants.

58. All lignite units have favorable configurations for Hg control. Every lignite unit is either equipped with a fabric filter, dry FGD with fabric filter, or wet FGD in combination with either a fabric filter or ESP. The unscrubbed units with fabric filters are fluid bed combustors, and therefore have very high free lime in the fly ash and therefore low SO_3 content in the flue gas. Furthermore, for units with fabric filters, ACI is highly effective for capture of Hg. Therefore, units with fabric filters alone or in combination with wet or dry FGD can achieve very high Hg capture in a consistent manner. Units with ESPs followed by a wet FGD are also capable of achieving high capture efficiency on a consistent basis because wet FGD systems are capable of high Hg capture, and especially when used in combination with ACI. Wet FGD is extremely effective in capturing oxidized mercury, as demonstrated by the low Hg emissions achieved at the Conemaugh plant despite the high Hg content of the coal used there.

2. ***Other issues regarding Hg control raised in Attachment B, the Cichanowicz report***

59. The Cichanowicz report[74] argues that the annual Hg rate used by EPA does not factor the 30-day rolling average or account for variability. It then gives examples of situations where some daily averages exceeded 1.2 lb/TBtu. The data shows that the facilities with the lowest number of variances are those with fabric filters, dry scrubbers, or lignite units with wet FGD. All of the lignite units are either equipped with a baghouse, a dry scrubber with baghouse, or wet FGD in combination with ESP or baghouse. As a result, the lignite units are likely to be well controlled in a relatively consistent manner.

60. Section 7.2 of the Cichanowicz report discusses a wide range of factors that may or may not impact Hg capture. At this point in time, Hg capture has been performed in the United States for nine years under the MATS rule. If state rules are considered, Hg has been controlled at some coal fired power plants for much longer than this – about 20 years in some cases. In this time, a great deal has been learned about the various factors that impact Hg control, and companies know how to address each of the factors identified in the Cichanowicz report.

Refined coal

61. Refined coal refers to coal that is treated to reduce emissions (typically with chemicals that may include bromine for oxidizing Hg) and must offer *" . . . a reduction of at least 20 percent of the emissions of nitrogen oxide (NOx) and at least 40 percent of the emissions of either sulfur dioxide (SO2)*

[74] pages 8-13 of the Cichanowicz report

or mercury (Hg) released when burning the refined coal (excluding any dilution caused by materials combined or added during the production process), as compared to the emissions released when burning the feedstock coal or comparable coal predominantly available in the marketplace as of January 1, 2003;"[75]

62. Refined coal, due to tax code provisions, once received beneficial tax treatment. The Cichanowicz report states that this is "no longer a viable option". There is no technical reason why utilities cannot continue to treat the coal, although the tax benefit is no longer available. In fact, some facilities add bromine to their coal without the tax benefit associated with refined coal. Simply adding bromine, as practiced by some facilities, would not have qualified for refined coal provisions because bromine only addresses Hg. But, this could be performed to improve Hg capture.

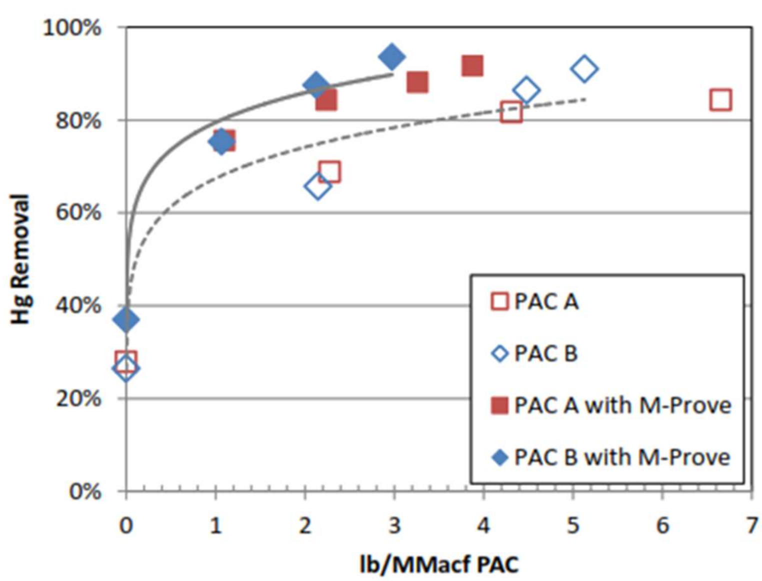
Sorbent Injection

63. Sorbent injection has been deployed on hundreds of coal-fired boilers under a very wide range of coal types, plant configurations and operating conditions. Some of these applications go back to over 20 years ago. Therefore, the statement in the Cichanowicz report that, "*Devising a reasoned prediction of Hg removal under variable conditions, including coal composition and the impact of changing sorbents is not possible with current available information"* suggests that little has been learned over these past 20 years and hundreds of coal power plant applications. To make this point, the Cichanowicz report cites tests at the Labadie plant, but it does not present the Labadie results. The Labadie test results, presented in the

[75] IRS, Production Tax Credit for Refined Coal, Notice 2009-90, https://www.irs.gov/pub/irs-drop/n-09-90.pdf.

2016 Mega Symposium cited by Cichanowicz, demonstrate that for given sorbent types and additives ("M-Prove" technology, in this case), the emissions performance in fact follows predictable trendlines, as shown in Figure 12. This testing was for the purpose of demonstrating the effects of additives and carbon types on improving treatment rate of brominated activated carbon. Indeed, the presentation stated that the additives demonstrated that effect. What the cited document therefore indicates is that – back in 2016 – the impact of changing sorbents or using additives was well understood. Technology suppliers had by 2016 developed means to enhance the performance of activated carbon. They had also identified the key variables impacting performance, permitting higher Hg capture in a predictable way.

Figure 12. Comparison of Mercury Removal with and without M-Prove Technology as a Function of PAC Injection Rate[76]



[76] Senior, C. et. al., "Reducing Operating Costs and Risks of Hg Control with Fuel Additives", Presentation to the Power Plant Pollutant Control and Carbon Management Mega Symposium, August 16-18, 2016.

SCR, FGD Co-Benefits

64. Many units do not need to rely primarily upon ACI for Hg control and can utilize what some call "co-benefit" Hg capture from control systems designed to capture other pollutants. Oxidized Hg is very efficiently captured in a wet FGD scrubber. SCR has the potential to oxidize Hg upstream of a wet FGD where it can be captured more efficiently. This is a phenomenon that has been examined since 2004 at the latest.[77] Companies incorporate this knowledge into their SCR catalyst management plans.[78] In fact, the Electric Power Research Institute (EPRI) developed and published in 2016 the results of their predictive modeling of Hg oxidation from SCR catalysts that showed high agreement between predicted and actual results.[79] This phenomenon, examined for close to two decades, is well understood and utilities incorporate this into their Hg compliance already. One lignite coal plant (Oak Grove in Texas) is currently equipped with SCR. It is uncertain if SCR will be installed on other lignite coal plants in the future.

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[77] *See* Renninger, S., Farthing, G., Ghorishi, S.B., Teets, C., Neureuter, J., "Effects of SCR Catalyst, Ammonia Injection and Sodium Hydrosulfide on the Speciation and Removal of Mercury within a Forced-Oxidized Limestone Scrubber", Joint EPRI DOE EPA Combined Utility Air Pollution Control Symposium, The Mega Symposium, Washington, D.C., August 30-September 2, 2004; Winberg, S., Winthum, J., Tseng, S., Locke, J., "Evaluation of Mercury Emissions from Coal-Fired Facilities with SCR-FGD Systems", DOE/NETL Mercury Control Technology R&D Program Review, Pittsburgh, PA, July 14-15, 2004; Senior, C.L, and Linjewile, T., "Oxidation of Mercury Across SCR Catalysts in CoalFired Power Plants", DOE/NETL Mercury Control Technology R&D Program Review, Pittsburgh, PA, July 14-15, 2004; U.S. Environmental Protection Agency, Air Pollution Prevention and Control Division, National Risk Management Research Laboratory, Office of Research and Development, "Control of Mercury Emissions from Coal Fired Electric Utility Boilers: An Update", Research Triangle Park, NC, February 18, 2005.

[78] Rutherford, S., Reeves, C., "SCR Catalyst Management for Optimal NOx and Hg Emissions control", Power Plant Pollutant Control and Carbon Management "MEGA" Symposium, August 16-18, 2016.

[79] Hinton, S., et al., "SCR Mercury Oxidation Modeling Efforts", Power Plant Pollutant Control and Carbon Management "MEGA" Symposium, August 16-18, 2016.

Hg Re-Emission

65. This phenomenon was first identified in the 1990's[80] and relates to the now well-understood effect that wet scrubber chemistry has on the fate of Hg that is captured. Early testing of wet FGD Hg capture found that in some cases elemental Hg would be released at higher levels than inlet levels, suggesting "re-emission" of captured Hg – oxidized Hg that had been captured in scrubber liquor could undergo a reduction reaction to form elemental Hg and then be released. This phenomenon is now well understood thanks to research, and methods have been developed to address it. The role of oxidation reduction potential (ORP) has been identified as a major factor in this phenomenon as well as sulfite chemistry. Management of ORP is one way to address Hg re-emission.[81] Other means of managing this that have been developed include use of sorbents to control Hg reemission,[82] sulfite control[83] and even flocculants to increase precipitation of Hg-containing solids. Since most of the lignite units have wet scrubbers, they will be

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[80] Gadgil, M., "20 Years of Mercury Re-emission – What Do We Know?", Power Plant Pollutant Control and Carbon Management "MEGA" Symposium, August 16-18, 2016.

[81] *See* Blythe, et al., "Investigation of Toxics Control by Wet FGD Systems", Power Plant Pollutant Control and Carbon Management "MEGA" Symposium, August 16-18, 2016; Blythe, et al., "Maximizing Co-benefit Mercury Capture for MATS Compliance on Multiple Coal-Fired Units", Power Plant Pollutant Control and Carbon Management "MEGA" Symposium, August 16-18, 2016; Steen, W., Blythe, et al., "Correlating FGD Oxidation-Reduction Potential Using Multivariate Data Analysis Techniques: A Path to Understanding Governing Behavior and Control Options", Power Plant Pollutant Control and Carbon Management "MEGA" Symposium, August 16-18, 2016.

[82] Pavlish, J., Lentz, N.., "Managing Mercury Scrubber Reemission and Maintaining MATS Compliance Using a Sorbent Approach", Power Plant Pollutant Control and Carbon Management "MEGA" Symposium, August 16-18, 2016.

[83] Patton, et. al., "WFGD Sulfite Control Testing at Seminole electric's Palatka Station Reduces Hg Re-emissions and Improves Trace Element in Purge Stream", Power Plant Pollutant Control and Carbon Management "MEGA" Symposium, August 16-18, 2016.

capable of capturing Hg in the scrubber with the benefit of the knowledge gained over the past nearly three decades.

Variability Due to Load Changes

66. The Cichanowicz report also cites 2016 documents that show that there is risk of Hg re-emission from wet FGD systems or changes in capture efficiency when there is a load change and ORP may change.[84] These 2016 documents also demonstrate that this effect is understood and methods to address them were being shown to be effective in 2016. These papers discuss the use of ORP, sulfite additives, or addition of sorbents to address the risk of Hg re-emission at different conditions, including load changes.

B. Cichanowicz criticism of EPA ESP upgrade cost information

67. The Cichanowicz report incorrectly categorizes the project at Labadie power plant Units 1 & 2 as an ESP upgrade.[85] It is, in fact, an ESP replacement project performed on half of the facility. ESP upgrade types are described in ATP 2021.[86] To be specific, an ESP upgrade utilizes the existing ESP casing and structure. When these are replaced, it is an ESP replacement. Ameren identified the project as replacement (not an upgrade) in their comments.[87] In Ameren's words, "Ameren retrofitted the entire ESP trains

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[84] *See* Blythe, et al., "Investigation of Toxics Control by Wet FGD Systems", Power Plant Pollutant Control and Carbon Management "MEGA" Symposium, August 16-18, 2016; Blythe, et al., "Maximizing Co-benefit Mercury Capture for MATS Compliance on Multiple Coal-Fired Units", Power Plant Pollutant Control and Carbon Management "MEGA" Symposium, August 16-18, 2016; Pavlish, J., Lentz, N.., "Managing Mercury Scrubber Reemission and Maintaining MATS Compliance Using a Sorbent Approach", Power Plant Pollutant Control and Carbon Management "MEGA" Symposium, August 16-18, 2016.

[85] page 17 of Cichanowicz report

[86] ATP 2021 at 16-23.

[87] Ameren Missouri comments submitted to Docket EPA-HQ-OAR-2018-0794 (hereinafter "Ameren comments"), https://www.regulations.gov/comment/EPA-HQ-OAR-2018-0794-5973.

on two units in 2014/2015. On each of these units, two of the three original existing ESPs had to be abandoned and one of the existing ESPs was retrofitted with new power supplies and flue gas flow modifications. A new state-of the art ESP was added to each unit to supplement the retrofitted ESPs."[88] These units are shown in Figure 13. Because these are new ESPs, with most of the existing structure abandoned, the cost is greater than the cost of an ESP upgrade, approaching the cost of a fabric filter retrofit.

Figure 13. New ESPs at Labadie units 1 & 2 and adjacent units 3 & 4 with older ESPs.[89]

68. The way the cost estimates were developed by EPA (as well as by ATP in ATP 2023), facilities that are expected to be unable to reduce PM emissions sufficiently with an ESP upgrade to meet the limit are estimated to install a fabric filter. Apparently, Ameren, the owner of Labadie, determined that an

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[88] *Id.*

[89] From Google Earth.

ESP upgrade would not be sufficient for the two units to get the full, four-unit facility in compliance, and they chose a more expensive approach for Units 1 & 2, and comply with a facility average, avoiding any cost on the other two units. At $149/kW and $163/kW (2014 dollars), respectively, per unit[90] the Unit 1 and Unit 2 ESP replacement projects approached the cost of a fabric filter on each of the units. As will be shown in the following paragraph, installing new ESPs on Labadie Units 1 & 2 enabled Ameren to comply with MATS at the full Labadie plant by making modifications to half of the plant capacity rather than the entire plant.

69. The Labadie project illustrates an aspect of the MATS rule that reduces cost - plant averaging – that makes the rule more economical. Ameren was able to comply with MATS on all four Labadie units through modifications at two of the four units at the Labadie plant. Because these retrofits enabled the full, roughly 2,400 MW, plant to comply with the MATS rule (as opposed to only the roughly 1,200 MW that were retrofit with new ESPs), the cost on a $/kW basis for MATS compliance was in fact roughly half of what would be calculated when using only the two units that were retrofit. When the cost is averaged over the entire facility, the capital cost on a $/kW basis is on the order of EPA's assumed cost for a major ESP upgrade.

70. The costs for the AES Petersburg ESP upgrade identified in the Cichanowicz report are roughly equivalent to the cost assumed by EPA for major ESP upgrades. This demonstrates that EPA's assumptions for ESP upgrades are consistent with industry data.

[90] Ameren comments. Further, this cost only applies to the two affected units. Since the new ESPs brought the full plant into compliance due to plantwide averaging, the cost on a $/kW basis should be half of this.

71. Given the above information, and data from other sources (see ATP 2021 and ATP 2023), the cost estimates used by EPA for ESP upgrades that were developed by Sargent & Lundy and utilized by EPA are similar to the costs that are independently presented in ATP 2021 and ATP 2023.

C. Contrary to what Mr. Bohrer believes, there is ample capacity to address any needed ESP modifications.

72. As noted earlier in this declaration, there will be adequate skilled labor to address any need for improving the performance of ESPs. EPA forecast 4 ESP rebuilds, 1 minor ESP upgrade, 4 typical ESP upgrades, and two fabric filter installations.[91] Other changes amounted to upgrades of filter bag material, increased O&M, or increased filter bag replacement frequency. Mr. Bohrer expressed concerns that four vendors might not be capable of performing the work in 3 years.[92] As noted earlier, the industry has managed to respond to other rules that entailed many more projects, and far more complex projects than envisioned from this rule. As noted earlier in this declaration, I do not expect there to be any risk of industry not being able to respond to the requirements of this rule. Sargent & Lundy has estimated that fabric filters can be installed within two years.[93] A fabric filter installation is a more extensive project than the most extensive ESP rebuild and would be even greater scope than an ESP replacement. So, an ESP rebuild, if needed, can be performed in under two years.

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[91] *See* EPA-HQ-OAR-2018-0794-6919_attachment_1.
[92] Exhibit 9, Declaration of Jason Bohrer, ¶ 23 in *National Rural Electric Coop. Assn. v. EPA*, No. 24-1179, Motion for Stay (D.C. Cir., June 21, 2024).
[93] Sargent & Lundy, "IPM Model – Updates to Cost and Performance for APC Technologies Particulate Control Cost Development Methodology", Final, April 2017, Project 13527-001, page 10.

D. Response to Mr. McLennan and reports on MRY power plant

73. Mr. McLennan and Minnkota Power Cooperative included two reports about the MRY plant that were prepared by Sargent & Lundy Corporation.[94] One is a May 2023 report "Mercury Testing Results for the MATS Residual Risk and Technology Review." The other is a June 2023 report, "Particulate & Mercury Control Technology Evaluation & Risk Assessment for Proposed MATS Rule." MRY plant has two units – one around 237 MW and the other about 447 MW. They are cyclone boilers equipped with cold-side ESPs, ACI and wet scrubbers. They are also equipped with SNCR for NOx control. As scrubbed units, they can capture Hg in the ESP while using ACI. Hg can also be captured in the wet scrubber. So, MRY has more options for Hg control than an unscrubbed facility with an ESP for PM control.

74. MRY was only able to test up to the limit of their current ACI system injection capacity. Therefore, the testing that was performed is not especially instructive. None of the testing explored increasing capture in the wet scrubber, which is widely known to be highly effective in capturing oxidized Hg.

75. Sargent & Lundy concluded that the existing system cannot meet the new, lower emission rate simply by increasing carbon injection to the limit of what the existing system is capable of. However, the June report (Attachment E) did identify the fact that the Hg was primarily in the elemental form. This is typical for lignite units due to the low halogen content of most lignite coals. Because of this, increasing oxidation of

[94] *See* Attachments A and E to Exhibit 9, Declaration of Robert McLennan, at 167 and 249 in *North Dakota v. EPA*, No. 24-1119, Amended Motion for Stay (D.C. Cir., June 7, 2024).

mercury through halogen addition would facilitate more capture in the ESP and especially the wet scrubber, which Sargent & Lundy stated can capture 90% of oxidized Hg.[95] Sargent & Lundy also identified other means to improve capture through ACI, such as increasing carbon injection capacity, improving ACI contact and testing other carbons or additives.

76. Sargent & Lundy acknowledged that additional testing could explore controlling Hg to 1.2 lb/TBtu (pages 10-12). They did not rule out the possibility, and as previously noted, identified methods that could be used to increase capture with ACI and with the scrubber.

COMMENTS BY PURVIS – EAST KENTUCKY POWER COOPERATIVE

77. Mr. Purvis (para 21) states that Spurlock unit 3 is not presently capable of meeting the new fPM limit on a sustained basis.[96] He claims that the baghouse is undersized to achieve the fPM limit. He states that a single hole the size of a human pinky finger in one of the bags could cause an exceedance of the new standard (para 25).

78. A failure of roughly a square inch (about the area of a pinky finger) may not sound like much. But, it is, in fact, a fairly significant failure. ATP's 2021 report[97] discusses the important mechanisms for bag failure. Use of a fPM CEMS will help identify possible filter material deterioration and the potential for more significant future failure. As discussed in ATP's 2021 report, options for extending bag life include changing to more durable

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[95] Attachment E to Exhibit 9, Declaration of Robert McLennan in *North Dakota v. EPA*, No. 24-1119, Amended Motion for Stay at 10-11 (D.C. Cir., June 7, 2024).
[96] Exhibit 4, Declaration of Jerry Purvis in *National Rural Electric Coop. Assn. v. EPA*, No. 24-1179, Motion for Stay at 11 (D.C. Cir., June 21, 2024).
[97] Staudt, J., *Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants, for* Center for Applied Environmental Law and Policy (CAELP), August 19, 2021, page 26.

fabrics and managing cleaning frequency. Some of the more cleanable fabrics and more durable fabrics became more available after 2012. EPA did account for both increased diligence and the potential for increased filter media replacement frequency or replacement with higher performance fabrics.

79. EPA's analysis suggests that Spurlock 3's 99th percentile emission rate was below 0.010 lb/MMBtu for most quarters. So, it appears that Spurlock 3 can be brought into compliance with additional diligence.

Respectfully submitted:

James E. Staudt

July 18, 2024

ATTACHMENT 1

ATTACHMENT 1.

James E. Staudt, Ph.D., CFA
Andover Technology Partners
1 Surf Village Unit B, Manchester-by-the-Sea, MA 01944

Summary: A consultant with decades of experience assisting companies, government agencies and non-government organizations that work in the energy and environmental sector. Engagements typically require a deep knowledge of technology and business. Dr. Staudt has published numerous technical papers and reports on regulatory requirements, emissions control technology, and clean energy.

2019: Adjunct Professor, University of Massachusetts, Lowell

Teaching undergraduate engineering courses

2018: Adjunct Professor, Merrimack College

Developed syllabus and taught a new course in Engineering Economics for students in the Master of Science in Engineering Management program administered by the Mechanical Engineering department. Also taught Materials Science.

2013 – Present

Volunteer reviewer for the Mass Ventures START venture funding program for the Commonwealth of Massachusetts. START is a program funded by the Commonwealth of Massachusetts to assist Massachusetts-based companies that have been successful in the Federal Small Business Innovation Research (SBIR) program.

1997 – Present

President, Andover Technology Partners

Provided consulting services to:

United States and state government agencies in development of clean air and clean energy regulations. Regulatory actions that were developed using Dr. Staudt's analysis include

US EPA Proposed Mercury and Air Toxics Standards (MATS) Revision[98]
US EPA Affordable Clean Energy Rule
US EPA Clean Power Plan
US EPA NOx SIP Call
US EPA Clean Air Interstate Rule
US EPA Clean Air Mercury Rule

[98] Work is cited at 40 CFR Vol. 88, No. 78, 24868 and 869

US EPA Regional Haze Rule[99]
Illinois Mercury Rule and NOx RACT rule
Consent Decree between US EPA, State of North Carolina and Tennessee Valley Authority
US EPA Cross State Air Pollution Rule
US EPA Mercury and Air Toxic Standards
National Emission Standards for Control of Hazardous Air Pollutants for
- Portland Cement Kilns
- Industrial Boilers
- Pulp and Paper Mills
- Iron and Steelmaking Facilities

Review of numerous stationary source permits in a range of industrial sectors

Environmental Non-Government Organizations
Developed numerous reports for these organizations or provided consulting services to them.

Developers of clean air or clean energy technologies
Market and industry strategy analysis

Owners of industrial facilities
Assisting clients in implementing and maintaining compliance, to include selecting and deploying emissions control technologies

Investors in companies in clean air or clean energy technology space
Assisting clients with evaluating investments in clean energy or clean air technology companies

1995-1997

Vice President, Spectrum Diagnostix (a subsidiary of Physical Sciences, Inc.) - Managed technology development and commercial operations for developer of diode laser based optical process instrumentation. Company was sold in 1997.

1990-1995

Product Director, NOx Control, Research-Cottrell – Managed engineering, operations, and sales of pollution control technologies to power plants and large industrial facilities

1990

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[99] Cited 143 times in 40 CFR Vol. 79, No. 20, pp 5032-5222

Physical Sciences, Inc. – Managed a US Department of Energy research program on energy. Developed business plan for what would later become Spectrum Diagnostix.

1988-1990

Programs Manager, Fuel Tech, Inc., Managed chemical process engineering group and commercial demonstration programs for air pollution control technology used at power plants and large industrial facilities.

1987-1988

Project Manager, Northern Research and Engineering Corporation. – Project manager for a turbomachinery design company owned by Ingersoll Rand.

1984-1987

Graduate student, Massachusetts Institute of Technology

1979-1984

US Naval Officer – Navy nuclear program

Publications

Dr. Staudt has published over 70 papers, journal articles or publicly available reports. In addition, he has also authored many reports for US EPA and other clients as part of his consulting practice that have been released to the public under the client's name.

Education and Professional Credentials

B.S. in Mechanical Engineering from the U.S. Naval Academy (1979)
M.S. (1986) in Engineering from the Massachusetts Institute of Technology (M.I.T.)
Ph.D. (1987) in Engineering from the Massachusetts Institute of Technology (M.I.T.) with a minor in Business Management
Chartered Financial Analyst (CFA) designation (2001)
US Navy Chief Engineer, nuclear power (1983)

Awards

2007 US Environmental Protection Agency Science and Technology Achievement Award

Providing the Public with a Comprehensive Summary of Technologies for Control of Mercury Emissions from Electric Utility Boilers

1994 and 2010 Institute of Clean Air Companies (ICAC) Special Achievement Awards

Professional Associations

Member, CFA Institute

Military Service

From 1979 to 1984 Dr. Staudt served as a commissioned officer in the U.S. Navy in the Engineering Department of the nuclear-powered aircraft carrier USS ENTERPRISE (CVN-65), attaining the rank of Lieutenant (O-3) prior to leaving the service.

Publications

1. Staudt, J., *Compliance Options Available to Individual Power Plants Under the Proposed Clean Air Act Section 111 GHG Rules,* December 18, 2023.
2. Staudt, J., *History of Flexible Compliance with Science-Based and Technology-Based Stationary Source Air Pollution Regulations,* December 18, 2023.
3. Staudt, J., *CO_2 and NOx Emissions from Natural Gas Combined Cycle and Natural Gas Combustion Turbine Power Plants,* September 23, 2023.
4. Staudt, J., *Assessment of Potential Revisions to the Mercury and Air Toxics Standards*, for Center for Applied Environmental Law and Policy, June 15, 2023
5. Staudt, J., *Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants – Addendum*, Analysis of the Cost of Complying with Lower Hg Emissions Levels, for Center for Applied Environmental Law and Policy (CAELP), January 5, 2023
6. Staudt, J. *Opportunities for Reducing Acid Gas Emissions on Coal-Fired Power Plants*, for Center for Applied Environmental Law and Policy (CAELP), April 5, 2022 available at: https://www.andovertechnology.com/articles-archive/
7. Staudt, J., *Natural Gas Cofiring for Coal-Fired Utility Boilers*, for Center for Applied Environmental Law and Policy (CAELP), February 12, 2022, available at: https://www.andovertechnology.com/articles-archive/
8. Staudt, J., *Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants*, for Center for Applied Environmental Law and Policy (CAELP), August 19, 2021; available at: https://www.andovertechnology.com/articles-archive/
9. Staudt, J., and Glesmann, S., White Paper – "The Past, Present, and Future of Smart Building Management", May 2020, available at: https://www.andovertechnology.com/articles-archive/
10. Staudt, J., "Heat rate measurement using Continuous Emission Monitoring Systems (CEMS) and comparison with fuel use data", Electric Power

Research Institute (EPRI) Meeting on Continuous Emission Monitoring Systems, May 2-3, 2018, Saint Louis

11. Staudt, J., "Using Publicly Available Heat Rate Data", Electric Power Research Institute (EPRI) Meeting on Improving Power Plant Heat Rate, February 21-23, Atlanta
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13. Staudt, J., "Natural Gas Conversion and Cofiring for Coal-Fired Utility Boilers", for Environmental Defense Fund, November 2014
14. Staudt J., Macedonia, J., "Evaluation of Heat Rates of Coal Fired Electric Power Boilers", Presented at the Power Plant Pollutant Control "MEGA" Symposium, August 19-21, 2014 , Baltimore, MD
15. Staudt, J. "Assessment of Bias in Measurement of Mercury Emissions from Coal Fired Power Plants – Comparison of Electronic CEMS and Sorbent Traps", Presented at the 10th Annual 10th IEA Mercury Emission from Coal Workshop, Clearwater, FL, April 23-25, 2014
16. Staudt, J., "Candidate SO_2 Control Measures for Industrial Sources in the LADCO Region", for Lake Michigan Air Director's Consortium, January 24, 2012.
17. Staudt, J., "Engineering and Economic Factors Affecting the Installation of Control Technologies– An Update", for US EPA Clean Air Markets Division, December 15, 2011
18. Staudt, J., "Air Pollution Compliance Strategies for Coal Generation", EUCI, Arlington, VA, December 5-6, 2011 available at www.AndoverTechnology.com
19. Staudt, J., "Labor Availability for the Installation of Air Pollution Control Systems at Coal Fired Power Plants" , October 31, 2011, at www.AndoverTechnology.com
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23. Staudt, J, Hoover, B., Trautner, P., McCool, S., Frey, J., "Optimization of Constellation Energy's SNCR System at Crane Units 1 and 2 Using Continuous Ammonia Measurement", The MEGA Symposium, Baltimore, MD, August 31-September 2, 2010
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27. Staudt, J., Erickson, C., "Selective Catalytic Reduction System Performance and Reliability Review – An Update", Power Gen, Orlando FL, December 2-4, 2008
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74. Staudt, J.E., "Ash Characterization and Deposition in Coal Water Slurry and Pulverized Coal Flames", Master's Thesis, Department of Mechanical Engineering, Massachusetts Institute of Technology, 1986.
75. Beér, J.M., Farmayan, W.F., Teare, J.D., Toqan, M.A., Benedek, K., Kang, S.W., Srinivasachar, S., Staudt, J.E., Walsh, P.M., and Tae-U, Yu., "The Combustion, Heat Transfer, Pollutant Emission and Ash Deposition Characteristics of Coal-Water Fuels", Phase III Program Final Report, The Energy Laboratory, Massachusetts Institute of Technology, November 1985.
76. Walsh, P.M., Monroe, L., Staudt, J.E., Beér, J.M., Sarofim, A.F., and Toqan, M.A., "Comprehensive Studies of Coal Mineral Behavior During Combustion", Final Report, The Energy Laboratory, Electric Utility Program, Massachusetts Institute of Technology, October 1985.

Government and Public Sector Consulting Projects

Title: Support to US EPA – Clean Air Markets Division
Client: EPA Clean Air Markets Division through ERG
Scope: Supporting US EPA, performing various analysis as needed.
Period of Performance: 2019-present

Title: Assistance on Affordable Clean Energy Plan
Client: EPA Clean Air Markets Division through ERG
Scope: Performed analysis of labor impacts of heat rate improvements and clean energy technologies.
Period of Performance: 2018-2019

Title: Assistance on Clean Power Plan
Client: Navajo Nation, through Navajo Tribal Utility Authority
Scope: Assisting Navajo Nation with technical analysis of Clean Power Plan proposal, to include interaction with electric utility companies, analysis of compliance options and meetings with EPA Assistant Administrator for Air and Radiation.
Period of Performance: 2014-2015

Title: Impact to Labor Demand from Heat Rate Improvements on Existing Fossil Power Plants
Client: EPA Clean Air Markets Division through ICF International
Scope: A review of technical methods and potential labor impacts of heat rate improvements that might result from EPA regulation of Greenhouse Gases (GHGs) from existing fossil power plants.
Period of Performance: 2013-2014

Title: Best Available Retrofit Technology (BART) analysis and BART related support
Client: EPA Regions 8 and 9 - through EC\R and ICF International, respectively
Scope: Performed BART technology and cost analysis for industrial sources and electric generating units (visibility analysis performed by others). Also assisted EPA regions respond to comments, as needed. Industrial sources

included industrial boilers, cement kilns, lime kilns, combustion turbines, and reciprocating internal combustion engines.
Period of Performance: 2012-2016

Title: Candidate Control Measures for SO_2 Control from Industrial Sources
Client: Lake Michigan Air Directors Consortium (LADCO)
Scope: Performed a study and published a report that evaluated candidate SO2 control measures for a wide range of industrial sources in the LADCO region, to include: Industrial Boilers, Cement Kilns, Lime Kilns, Iron and Steel Mills, Refineries, Chemical Plants, Glass furnaces, and others. A report was published and is available on the LADCO website:
Period of Performance: 2011/2012

Title: Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants
Client: MJ Bradley and Associates and Northeast States for Coordinated Air Use Management
Scope: Prepared a report in collaboration with MJ Bradley and Associates on the topic of control technologies for control of NOx, SO2, and Air Toxics (particle matter, acid gases, mercury, etc.) for coal fired power plants and the application of these technologies for compliance with US EPA rules. A report was published by the Northeast States for Coordinated Air Use Management (NESCAUM).
Period of Performance: 2011

Title: Greenhouse Gas Mitigation Options Database (GMOD)
Client: US EPA (through Eastern Research Group and RTI International)
Scope: Developed Greenhouse Gas Technology Database for US EPA for power plants and cement kilns. Effort includes collection and analysis of data on performance and cost of various greenhouse gas control technologies including CO2 capture, IGCC, and others.
Period of Performance: Spring 2009-2010

Title: Emissions Control for Power Plants
Client: US EPA (through ICF Consulting)
Scope: Comprehensive evaluation of NOx, SO_2, and CO_2 emissions from power plants and development of capital cost, variable and fixed operating cost algorithms for control measures as well as impacts (energy use, water use,

emissions reduction) for use in the Integrated Planning Model. Assisted EPA with analysis for Mercury and Air Toxic Standards, to include analysis of Information Collection Request (ICR) Data to determine emission levels and controls needed for different sources. Also analyzed the availability of and demand for labor and other resources necessary for compliance with the MATS and Cross State Air Pollution Rule (CSAPR).
Period of Performance: Fall 2009-2012

Title: Emissions Control for Cement Kilns
Client: US EPA (through ICF Consulting and Eastern Research Group)
Scope: Comprehensive evaluation of NOx, SO_2, and CO_2 emissions from cement kilns, and development of capital cost, variable and fixed operating cost algorithms for control measures as well as impacts (energy use, water use, emissions reduction) for use in the US EPA Industrial Source Integrated Solutions (ISIS) Model.
Period of Performance: 2008-2010

Title: Emissions Control for Iron and Steel Mills
Client: US EPA (through Eastern Research Group)
Scope: Comprehensive evaluation of NOx, SO_2, and CO_2 emissions from Iron and Steel Mills, and development of capital cost, variable and fixed operating cost algorithms for control measures as well as impacts (energy use, water use, emissions reduction) for use in the US EPA ISIS Multi-Sector Model.
Period of Performance: 2009-2010

Title: Emissions Control for Pulp and Paper Mills
Client: US EPA (through RTI International)
Scope: Comprehensive evaluation of NOx, SO_2, and CO_2 emissions from Pulp and Paper Mills, and development of capital cost, variable and fixed operating cost algorithms for control measures as well as impacts (energy use, water use, emissions reduction) for use in the US EPA ISIS Multi-Sector Model.
Period of Performance: 2009-2010

Title: NOx Control – NOx RACT
Client: State of Illinois, Environmental Protection Agency, Bureau of Air (Contract with Lake Michigan Air Director's Consortium)
Scope: Providing technical support to the Illinois Environmental Protection Agency's Bureau of Air in developing rules for control of NOx at electric

generating units, gas turbines and reciprocating engines and steel mills, cement plants, glass-manufacturing plants, refineries, and other industrial facilities.
Period of Performance: 2007-2009

Title: Best Available Retrofit Technology for EGU's in Illinois
Client: State of Illinois, Environmental Protection Agency, Bureau of Air (Contract with Lake Michigan Air Director's Consortium)
Scope: Providing technical support to the Illinois Environmental Protection Agency's Bureau of Air in evaluating BART for specific IL EGUs.
Period of Performance: 2007-2008

Title: Air Pollution Reduction at Tennessee Valley Authority Plants
Client: Attorney General of North Carolina
Scope: Providing expert witness analysis of methods to reduce air pollution from TVA coal power plants.
Period of Performance: 2006-2008

Title: NOx and SO_2 Cost of Control under the Clean Air Act Amendments
Client: US Environmental Protection Agency and ICF Consulting
Scope: Providing technical support to the US EPA Clean Air Markets Division and analyzing the cost of compliance with Title IV (NOx and SO_2 Acid Rain provisions) of the Clean Air Act Amendments (CAAA) and the NOx SIP Call and OTC NOx Budget Rule that were issued under Title I of the CAAA.
Period of Performance: 2006

Title: Mercury Emissions Control
Client: State of Illinois, Environmental Protection Agency, Bureau of Air (Contract with Lake Michigan Air Director's Consortium)
Scope: ATP provided technical support to the Illinois Environmental Protection Agency's Bureau of Air in developing a rule to meet the Illinois Governor's proposed reduction in Illinois power plant mercury emissions.
Period of Performance: 2006 - completed

Title: Update of Coal Utility Environmental Cost (CUECost) Model
Client: US EPA and ARCADIS, P.O. Box 13109, Research Triangle Park, NC 27709
Scope: ATP developed cost and performance algorithms for mercury emissions control including cobenefits, powdered activated carbon and halogenated powdered activated carbon. Also developed SO_2 control cost and performance

algorithms. These and other updates were incorporated into EPA's CUECost model.
Period of Performance: 2005-2006

Title: SO_2 Control Cost and Performance
Client: US EPA and ICF Consulting, 9300 Lee Highway, Fairfax, VA 22031 (703) 934-3071
Scope: ATP supported ICF Consulting and US EPA in developing cost and performance models for limestone forced oxidation (LSFO) and Spray Drier Absorber technology that will be incorporated into the Integrated Planning Model. Reviews of installed installation data and vendor quotes was used to develop algorithms.
Period of Performance: 2005

Title: NOx Control Workshop, Dalian, China
Client: US Department of Energy, National Energy Technology Laboratory, and Arcadis
Scope: ATP developed and taught a workshop on NOx control methods, especially post combustion controls for coal-fired power plants, to Chinese delegates.
Period of Performance: 2005

Title: Reliability of Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) Systems for High Pollutant Removal Efficiencies on Coal Fired Utility Boilers
Client: US Environmental Protection Agency and ICF Consulting, 9300 Lee Highway, Fairfax, VA 22031 (703) 934-3071
Scope: ATP evaluated the reliability of recently installed SCR systems designed for very high removal efficiencies (over 90%) and also FGD technologies.
Period of Performance: 2004

Title: Performance and Cost of Mercury and Multipollutant Emission Control Technology Applications on Electric Utility Boilers, EPA-600/R-03/110 issued October 2003
Client: US EPA and ARCADIS, P.O. Box 13109, Research Triangle Park, NC 27709
Scope: ATP was the principal subcontractor to ARCADIS in evaluating the performance and cost of mercury and multipollutant control methods (NOx,

SOx, PM, Hg) for the US EPA. ATP developed cost and performance models to assess the emission control strategies for control of mercury, NOx, SO_2 and PM and other pollutants for about 50 model plants. Results are documented in EPA report EPA-600/R-03/110 issued October 2003, which may be downloaded from EPA's web site.
Period of Performance: 2002-2003

Title: Cost and Performance of Pollution Controls
Client: US EPA and ICF Consulting, 9300 Lee Highway, Fairfax, VA 22031 (703) 934-3071
Scope: As a subcontractor to ICF Consulting, ATP has evaluated the cost and performance of state-of-the-art combustion NOx controls and the cost and performance experienced with Selective Catalytic Reduction systems installed in response to the NOx SIP Call. Project entailed review of public information and interviews with industry contacts to collect cost and performance information, and reporting of the information to EPA and ICF.
Period of Performance: fall 2002 – fall 2003

Title: Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies, EPA-600/R-02/073, October 2002
Client: US EPA and ARCADIS, P.O. Box 13109, Research Triangle Park, NC 27709
Scope: As a subcontractor to ARCADIS, ATP analyzed the feasibility of complying with Multipollutant Control programs under evaluation by EPA. Report examined the feasibility of mercury, SO_2, and NO_X control technology implementation based upon forecasted technology installation schedules for the Clear Skies Initiative.
Period of Performance: Fall 2001 - Spring 2002

Title: Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines – Technologies and Cost Effectiveness
Client: Northeast States for Coordinated Air Use Management
Scope: Comprehensive report on technologies, performance and cost effectiveness of methods to control NOx from gas turbines, cement kilns, industrial boilers, and internal combustion engines.
Period of Performance: released December 2000

Title: Status Report on NOx Control Technologies and Cost Effectiveness for Utility Boilers
Client: Northeast States for Coordinated Air Use Management
Scope: Comprehensive report on technologies, performance and cost effectiveness of methods to control NOx from utility boilers.
Period of Performance: released December 2000

Industrial Consulting Projects

Client: Constellation Energy
Scope: Advised client on air pollution control technologies for use at Constellation power plants.
Period of Performance: 2006 - 2009

Client: Chase Power
Scope: Advised client on emission control technologies for use at proposed 1200 MW petroleum coke fired power plant.
Period of Performance: 2007/8

Client: Arizona Public Service Company
Scope: Advised client on emission control technologies for use at Arizona Public Service utility coal plants.
Period of Performance: 2003/2004

Client: GE Contract Services, Newington Energy, Newington, NH
Scope: Advised client on emission control technology issues relating to combined-cycle power plant with two GE Frame 7F combined cycle.
Period of Performance: 2003/2004

Client: Dick Corp. at AES Granite Ridge, Londonderry, NH
Scope: Advised client on emission control technology issues relating to combined-cycle power plant with two Siemens Westinghouse 501G combined cycle turbines.
Period of Performance: 2003/2004

Client: Wyeth Biopharma, One Burtt Road, Andover, MA 01810
Scope: Advised client on emission control technologies associated with client's gas turbine cogeneration facility equipped with Solar Taurus combined cycle turbines.
Period of Performance: fall 2000 - spring 2001

Client: Allegheny Energy
Scope: Advised client on cost-effectiveness of various methods of complying with emission control requirements at a PURPA Qualifying Facility in the Allegheny system. Support included technical evaluation of alternatives and economic analysis of alternative, including evaluation of allowance trading.

Services included expert witness testimony in an arbitration hearing.
Period of Performance: spring 2000

Client: Texas Industries
Scope: Performed a comprehensive technical analysis on the emission reduction process that is used on TXI and other cement kilns to increase production and reduce air pollution. Also advised TXI regarding emissions control methods for cement kilns.
Period of Performance: Fall 1999

Client: NRG Somerset Operations, 1606 Riverside Avenue, Somerset, MA 02726
Scope: Optimization of client's emission control system on coal-fired electric utility boiler. Significant improvements in system operation resulted from this program.
Period of Performance: 1999 through 2001

Client: Conectiv, Wilmington, DE
Scope: Optimization of client's emission control system on coal-fired electric utility boiler, including combustion tuning and consulting on SNCR operation.
Period of Performance: 1997, 1998, 2001, 2002

Client: PG&E Generating, 7500 Old Georgetown Road, Bethesda, MD 20814
Scope: Advised PG&E Generating on expected environmental upgrade costs on several electric generating plants that PG&E Generating was considering for acquisition.
Period of Performance: Spring 1999

Non Government Organizations

Client: Center for Environmental Law and Policy
Scope: Prepared reports on gas cofiring on coal-fired boilers, methods to improve PM and Hg emissions from coal-fired boilers, and methods to improve acid gas emissions from coal-fired utility boilers. Also published reports on US EPA's proposed revisions to the Mercury and Air Toxic Standards, and on US EPA's proposed Section 111 Greenhouse Gas Rule. Reports are available at www.AndoverTechnology.com
Period of Performance: 2020-2023

Client: Environmental Defense Fund
Scope: Various reports and engineering studies, to include gas conversion of coal-fired utility boilers.
Period of Performance: 2010-2021

Client: Natural Resources Defense Council
Scope: Various engineering studies to examine heat rate improvements on power plants, commenting on EPA regulations.
Period of Performance: 2010-2018

Client: Sierra Club
Scope: engineering studies to include evaluation of SO2 methods on select power plants.
Period of Performance: roughly 2018