Andover Technology Partners 978-683-9599
Consulting to the Air Pollution Control Industry

Consulting regarding proposed repeal of the 2024 MATS Rule

C-25-EDF-1

to:

Environmental Defense Fund

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Background

The Environmental Defense Fund (EDF) has contracted with Andover Technology Partners (ATP) to prepare a report regarding EPA's proposal to roll back the 2024 Mercury and Air Toxics Standards (MATS) update rule, and address several questions, the findings of which are presented in the following report.

Program Results

In the following sections, I will address specific issues raised by EPA in their June 2025 proposed repeal of amendments to the National Emission Standards for Hazardous Air Pollutants (NESHAP): Coal- and Oil-Fired Electric Utility Steam Generating Units. This proposed action would repeal the 2024 MATS update rule.

EPA is incorrect in stating that the cost per ton of fPM or non-Hg metal HAPs is too high

The examples that EPA provides to argue that the rule is too expensive are flawed. The agency relied upon a comparison with two rules.

- The risk and technology review (RTR) for the petroleum refinery NESHAP was released in 2015 and the cost estimates are therefore based upon a dollar year no later than 2015. As a result, the estimates are not comparable. The 2025 Chemical Engineering Plant Cost Index (CEPCI) was 556.8. The 2019 CEPCI was 607.5, indicating that the cost of the 2024 rule estimated by EPA should be reduced by at least 10% to make them comparable.
- The RTR for the Integrated Iron and Steel NESHAP was more recent, but also estimated a cost effectiveness of \$160,000/ton of fPM removed, well above the \$35,000/ton of fPM removed estimated for the 2024 rule.

These are, therefore, not apples-to-apples comparisons. Moreover, EPA calculates each cost per ton (fPM, fPM2.5, and non-Hg metal HAPs) by dividing the total estimated cost by the estimated mass reduction in the individual pollutant.[1] Therefore, if the cost per ton for *any one* of these pollutants is reasonable, the control cost should be regarded as reasonable. Furthermore, as will be discussed in more detail, if all cost impacts are accounted for, the cost per ton will be less than what EPA estimated costs to be.

Excluding Colstrip, the cost of the rule is rather modest

EPA acknowledges that, excluding the Colstrip power plant, the fPM standard of 0.010 lb/MMBtu is achievable without having to retrofit a fabric filter. Those other facilities that may need changes can be addressed with relatively inexpensive modifications of their existing equipment. Therefore, the cost should not be an obstacle to meeting this limit for nearly all units. A large portion of the total estimated expense is limited to Colstrip. Setting aside the cost associated with a baghouse retrofit at Colstrip substantially reduces the fPM control cost for the rule by removing the single most expensive fPM control project. The annualized cost for fPM control, excluding Colstrip, is \$50 million per year versus \$87 million per year when Colstrip is included. Using EPA's cost workbook, the cost effectiveness for metal HAPs for all units excluding Colstrip is \$8.4 million per ton and capture of fPM is \$33,000 per ton.

In fact, what the results do show is that better emission control levels are possible. EPA found that 93% of all units are meeting a 0.010 lb/MMBtu emission level and 77% of units are under 0.006 lb/MMBtu.[2] Clearly, achieving a 0.010 lb/MMBtu emission level is achievable at a reasonable cost because 93% of the facilities are already doing that.

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[1] See MATS RTR Technical Memo_EPA_HG-OAR-2018-0794-6919_attachment_1.xlsx

[2] 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

Therefore, setting aside Colstrip for the moment, the other units can comply with the 0.010 lb/MMBtu limit of the 2024 MATS update rule at a significantly lower cost-per-ton than estimated by EPA.

Colstrip is unique in not having updated its PM control technology in 40 years

Regarding Colstrip, it is the only facility that EPA has determined will require a new fabric filter to meet the finalized standard of 0.010 lb/MMBtu. The reason is simple. Colstrip is the only operating power plant remaining in the United States that is not currently planned for retirement, continues to use a venturi scrubber for SO_2 control and lacks a dedicated PM control device. Venturi scrubbers are outdated technology that were used in the past because they included fPM control and SO_2 control in a single device.

Table 1 shows the coal power plant units that, according to EIA Form 860, were equipped with venturi scrubbers in 2009. The table includes the in-service year of the venturi scrubbers. It also shows if the facility is retired (retired), if it is operating but planned for retirement (planned retirement), or if it has retrofit other technology. Of these facilities, Colstrip is the only operating facility not planned for retirement that continues to use this technology, and the only plant to install this technology after 1980. Except for Colstrip 3 and 4, each of these units has been either retired, has announced plans for retirement, or was retrofitted with more current control technology. For example, the Dave Johnston plant in Wyoming replaced its 1970s vintage venturi scrubber with dry scrubbers and baghouses in 2010 and 2012. Of the over 300 coal EGUs equipped with scrubbers since 1986, none have installed venturi scrubbers. Venturi scrubbers are clearly antiquated and obsolete technology. The Colstrip venturi scrubbers are, in effect, the last living dinosaurs. As demonstrated in Staudt Declaration 2024,[3] the Colstrip scrubbers are also among the oldest scrubbers of any kind still operating in the United States coal fleet. The only reason that Colstrip remains the only facility to possibly need to add a fabric filter is because, unlike every other facility in the United States, it has not updated its fPM control technology in 40 years.

No: EPA-HQ-OAR-2018-0794, January 2024

[3] Staudt, J., Declaration as an Exhibit for Opposition to Environmental and Public Health Respondent-Intervenors to Petitioners' Motions for Stay, submitted to United States Court of Appeals for the District of Columbia Circuit, re: State of North Dakota, et. al, v. U.S. Environmental Protection Agency, et. al. submitted July 22, 2024, https://www.andovertechnology.com/wp-content/uploads/2024/07/Staudt-Declaration-final-072124.pdf, hereafter, Staudt declaration 2024, see Figure 7

Table 1. Coal power plant units equipped with venturi scrubbers in 2009 (EIA Form 860)

UTILITY_NAME	PLANT_NAME	STATE	INSERVICE_YR	COMMENT*
Westar Energy Inc	Lawrence Energy Center	KS	1969	retired
Westar Energy Inc	Lawrence Energy Center	KS	1969	planned retirement
Westar Energy Inc	Lawrence Energy Center	KS	1971	planned retirement
Arizona Public Service Co	Four Corners	NM	1972	planned retirement
Arizona Public Service Co	Four Corners	NM	1972	planned retirement
Arizona Public Service Co	Four Corners	NM	1972	planned retirement
PacifiCorp	Dave Johnston	WY	1972	SD/FF planned retirement
Kansas City Power & Light Co	La Cygne	KS	1973	planned retirement
Nevada Power Co	Reid Gardner	NV	1974	retired
Nevada Power Co	Reid Gardner	NV	1974	retired
PPL Montana LLC	Colstrip	MT	1975	retired
FirstEnergy Generation Corp	Bruce Mansfield	PA	1976	retired
Northern States Power Co - Minnesota	Sherburne County	MN	1976	planned retirement
Nevada Power Co	Reid Gardner	NV	1976	retired
Ameren Energy Resources Generating Co.	Duck Creek	IL	1976	retired
PPL Montana LLC	Colstrip	MT	1976	retired
Orion Power Midwest LP	Elrama Power Plant	PA	1976	retired
Prairie Power, Inc	Pearl Station	IL	1976	retired
FirstEnergy Generation Corp	Bruce Mansfield	PA	1977	retired
Arizona Public Service Co	Cholla	AZ	1978	retired
Southern Illinois Power Coop	Marion	IL	1979	retired
PPL Montana LLC	Colstrip	MT	1984	
PPL Montana LLC	Colstrip	MT	1986	

*Comment shows if unit is retired (retired) , a retirement date has been announced (planned retirement), or if another technology has been installed at some point. SD/FF= Spray Dryer Fabric Filter retrofit

Considering all cost impacts, a baghouse at Colstrip will be significantly less costly than EPA has estimated

Were Colstrip to install a baghouse to comply with the 0.010 lb/MMBtu standard, the Hg control costs would drop substantially. As will be discussed later in this document, activated carbon injection (ACI) is extremely effective when used in combination with a baghouse. This would likely result in millions of dollars per year in savings on activated carbon. For example, if the ACI injection rate at Colstrip was reduced from 3 lb/million ACF to 2 lb/million ACF,[4] and the facility operated near full load for 8000 hours per year, the annual activated carbon demand would be reduced from about 8.7 million pounds to about 5.8 million pounds. If the activated carbon costs $1.15 per pound, the savings at Colstrip would be $3.3 million per year. This was not factored into the fPM analysis performed by EPA. As noted by EPA, these are probably conservative estimates since some units noted by EPA with ESPs added carbon at rates of 5.0

[4] These treatment rate and carbon cost assumptions are consistent with those in 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

lb/MMBtu and the baghouse-equipped Oak Grove units had treatment rates of 0.5 lb/MMBtu.[5] At this change in rate, Colstrip's cost of controlling Hg would drop from about $16.7 million per year to about $1.7 million per year, a savings of about $15 million per year, which is about 41% of EPA's estimated annual cost of the baghouse retrofit at Colstrip. The control cost would drop to about $22 million per year from $37 million per year. Thus, installing a baghouse would significantly reduce ACI demand, which will offset a large portion of the cost of a baghouse.

If the estimated $15 million annual reduction in ACI cost resulting from a baghouse installation is factored in, the annual cost for all facilities drops from $87 million to $72 million. This reduces the cost per ton for all facilities to $28,500 per ton of fPM and $8.7 million per ton of non-Hg metal HAPs.

EPA requested comment on other cost-effective and achievable alternative standards

EPA determined that, with the exception of Colstrip, the currently finalized standard of 0.010 lb/MMBtu is readily achievable for all facilities without addition of a fabric filter. EPA should have examined other, alternative emission standards. For example, according to EPA's estimate in support of the 2024 MATS update rule, an emission rate of 0.015 lb/MMBtu could be achieved at a total annualized cost of $39 million and cost per ton of fPM of $31,000 per ton.[6]

Alternatively, a standard of 0.020 lb/MMBtu could have been considered. According to EPA's data from the MATS update rule analysis[7] Colstrip is already achieving close to 0.020 lb/MMBtu on average and under 0.020 lb/MMBtu if the 99th percentile of the two lowest quarters is used.

An alternative emissions standard of 0.015 lb/MMBtu or 0.020 lb/MMBtu would also prevent emissions backsliding which might occur if companies who are able to control to much lower levels grow comfortable with letting emissions rise.

It is also notable that, at a higher fPM emission rate limit, the cost of a PM CEMS is reduced. EPA's primary concern with the cost of PM CEMS was the cost of calibration at lower fPM levels due to longer sample times. Were EPA to increase the fPM rate limit, the cost of a PM CEMS gets lower, undermining EPA's argument against a PM CEMS requirement.

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

In my 2015 Declaration before the United States Court of Appeals for the District of Columbia Circuit,[8] as well as Staudt Declaration 2024, 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.

EPA's *ex ante* estimates are based upon technical options that are understood at the time of the rulemaking. 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

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[5] Ibid, page 42

[6] See MATS RTR 2024 Technical Memo_EPA-HQ-OAR-2018-0794—6919_attachment_1.xlsx

[7] Ibid

[8] Staudt, J., Declaration before United States Court of Appeals for the District of Columbia Circuit, September 23, 2015; available at: https://www.andovertechnology.com/wp-content/uploads/2020/09/Staudt-Declaration_2015_09_24_13_19_52-2.pdf

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 (CAA) Section 112(d)(6) recognizes that methods for controlling emissions improve over time.

> *"[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."*[9]

The 2021[10] and 2022[11] ATP reports identified numerous technological developments that occurred after the 2012 MATS rule, including: advanced activated carbons, advanced reagent 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. For example, in my September 2015 Declaration submitted to the United States Court of Appeals for the District of Columbia Circuit[12] I estimated that EPA's ex ante cost estimate overestimated the annual costs of the 2012 MATS Rule by over \$7.2 billion per year. Instead of \$9.6 billion per year estimated by EPA prior to the rule, the cost of the rule was no more than \$2.4 billion per year. *The annualized cost turned out to be only 25% or less of the ex ante estimate.*

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 (e.g., the Clean Air Interstate Rule, the Cross-State Air Pollution Rule, and the Regional Haze Rule). 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 electrostatic precipitator (ESP). Major changes to the ESP would have a significant cost impact that would make a change to lower sulfur fuels less economical. However, as noted in a 2023 ATP report,[13] 1990 and 1997 Air Markets Program Data demonstrates that, of the Phase I Title IV units, only 10.5% installed new flue gas desulfurization (FGD) systems while staying with their original fuel or switching to higher sulfur fuel, about 70.7% changed to lower sulfur fuels, and 18.8% continued with similar fuel sulfur levels as in 1990, relying upon use of SO_2 credits for compliance with the Title IV Acid Rain Program. Changing fuels was made possible through use of FGC, a technology that was not patented until 1993, three years after the 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.

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

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[9] 42 U.S.C. § 7412(d)(6).

[10] 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.

[11] 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.

[12] Staudt, J., Declaration before United States Court of Appeals for the District of Columbia Circuit, September 23, 2015; https://www.andovertechnology.com/wp-content/uploads/2020/09/Staudt-Declaration_2015_09_24_13_19_52-2.pdf

[13] 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.

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 selective non-catalytic reduction (SNCR). As described in ATP's 2023 report,[14] although EPA stated that state NOx Reasonably Available Control Technology (RACT) emission limits set by the states were to be "consistent with the most effective level of combustion modification reasonably available for its individual affected sources,"[15] in several cases, coal-fired EGUs selected post-combustion SNCR over improved combustion controls. SNCR had been available prior to this point, but there was very little experience with its use on coal-fired EGUs at this point. Once faced with the need to reduce NOx emissions, utilities became more open to using SNCR technology, which was effective in helping units comply with the RACT requirements established by the state.

Benefits of PM CEMS

PM CEMS produce much more accessible and transparent data than the quarterly test data in EPA's WEBFIRE.

PM CEMS permit more transparent access to PM data than what is currently available in EPA's Webfire database. The Webfire database only publishes quarterly data report pdf files that must be individually retrieved and searched. PM CEMS allow for electronic data availability and reporting on a far more frequent basis, similar to NOx and SO_2 or even Hg emissions data. Electronic data availability would enable EPA to manage information at a lower cost. It would also increase transparency.

EPA's suggestion that other systems and parameters can be used to indicate a PM control device malfunction is unsupported.

EPA argues (90 FR 25542) that methods other than PM CEMS can be used to detect equipment malfunction:

> *For example, operators at EGUs with an ESP can track opacity, secondary corona power, secondary voltage (i.e., the voltage across the electrodes), and secondary current (i.e., the current to the electrodes) to ensure proper functionality. For EGUs with FFs, bag leak detection systems (BLDS) and parameters like pressure differential (i.e., pressure drop), inlet temperature, temperature differential, exhaust gas flow rate, cleaning mechanism operation, and fan current can serve as reliable indicators.*

This claim is unsupported for a number of reasons that are described in the following paragraphs.

EPA did not perform or provide any analysis to support its opinion regarding non-CEMS methods of malfunction detection and has no requirement to even monitor or characterize these parameters

First, EPA has not performed *any* technical analysis to demonstrate that *any* of these parameters can be monitored and *reliably* indicate an equipment failure that impacts PM emissions in a timely manner. It is unclear if any of these methods offer the same sensitivity and reliability as information from a PM CEMS, or offer the timeliness of the impact on fPM emissions. EPA merely speculates that these methods can be relied upon without offering any evidence of the same.

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[14] *Id*. at 12-15.
[15] 57 Fed. Reg. 55,620, 55,626 (Nov. 25, 1992).

The documents at the links EPA cites[16] are only general documents that do not examine specifically the level of sensitivity (how quicky or readily a problem can be identified) or interaction with other plant parameters (to what degree other plant effects can mask a problem that increases fPM emissions – discussed more in the next paragraph). For example, EPA provides no examples of how a specific parameter would be monitored, how effective it is at indicating a particular malfunction, and how the change in monitored parameter relates to a change in PM emissions.

Second, while abnormal conditions for any of these parameters *might theoretically* be used to indicate a malfunction,[17] to do that in practice it would be necessary to somehow account for other variations that impact the parameters, understand any deviations from normal indications, and identify the impact on PM emissions. For example, *all of these parameters are impacted by normal load changes*, *normal furnace cleaning operation, changes in coal properties, excess air level, and other normal operations*. For each unit, it would *first* be necessary to perform comprehensive testing under a large variety of conditions to establish the normal range for these parameters under the full range of conditions and therefore determine which parameters, or combination of parameters, indicate a PM device malfunction, and the impact on fPM emissions. This is a completely impractical thing to do, and even after all of that testing was done, one would still be uncertain if every combination of conditions had been addressed. Moreover, in this proposal, EPA has not established this level of parameter testing as a requirement or even a recommendation, nor presented any evidence about how this would be done or its effectiveness (both sensitivity and timeliness in finding a problem that impacts fPM emissions), and it is therefore not a substitute for a PM CEMS.

To reiterate, even if monitoring these parameters could reliably be used to identify malfunctions with the same sensitivity of a PM CEMS (which no one, including EPA has been able to establish), without a *requirement* to continuously monitor and maintain a record of each of these parameters, these parameters cannot be used as a reliable means to indicate a PM control equipment malfunction. In this proposal, EPA has not established this as a requirement, and monitoring of these parameters is therefore not a substitute for a PM CEMS. It therefore fails in two respects: 1) it is not a requirement, and; 2) no one has been able to establish this to be a reliable means to identify malfunctions with the same sensitivity of a PM CEMS.

Simply put, EPA hasn't provided any evidence that monitoring of these parameters can be a substitute for PM CEMS in demonstrating compliance with the fPM limit and has not established a requirement to use any of these methods in a way that could substitute for PM CEMS in quickly identifying problems with controls.

Data does not support EPA's contention that monitoring parameters are a substitute for PM CEMS

Examination of PM CEMS data makes it clear that the parameters EPA offers as a substitute for PM CEMS have not been used the way the agency suggests. Comments on EPA's rule[18] include data from the Coronado Generation Station and demonstrate that it went for several

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[16] https://www.epa.gov/air-emissions-monitoring-knowledge-base/monitoring-control-technique-electrostatic-precipitators
https://www.epa.gov/air-emissions-monitoring-knowledge-base/monitoring-control-technique-fabric-filters

[17] It is unclear how sensitive any of these are as indicators of a PM control system malfunction.

[18] 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

quarters with increasing emissions before reducing its emissions. Coronado was equipped with a PM CEMS. This data demonstrated that the plant was indeed capable of controlling PM emissions to below 0.010 lb/MMBtu. See Figure 1, which shows the mean fPM rate and the 99th percentile fPM rate. The figure also shows the two EPA reference quarters used in the rule development. Presumably, Coronado, equipped with ESPs, should have had ability to monitor parameters such as "opacity, secondary corona power, secondary voltage (i.e., the voltage across the electrodes), and secondary current (i.e., the current to the electrodes)." However, if a plant such as Coronado didn't have the ability to monitor these parameters, then EPA's recommendation is clearly not a viable approach. If Coronado did have the ability to monitor all of these parameters, clearly, they are not using the information in the manner that EPA claims they would. Nevertheless, it is clear in Figure 1 that deteriorating performance extended over several quarters before being corrected – in one case two years from late 2018 through early 2021. The facility never actually exceeded or reached the limit of 0.03 lb/MMBtu. So, the motivation to address whatever was adversely impacting emissions could remain low for many quarters. Clearly, EPA's suggestion that these parameters are useful for identifying equipment malfunctions that impact PM emissions is either not being practiced or is ineffective. Since EPA has not required monitoring of these parameters and has not provided any evidence that monitoring these parameters would be effective (and the data actually demonstrates otherwise), EPA's recommendation is without any merit.

Commenters to EPA's 2024 rule claimed that the differences between reported fPM emissions in quarters at the Coronado facility are the result of "myriad factors, likely chief among them the units' duty and coal variability,"[19] rather than issues that could be corrected with the PM control device. However, their assertion is not supported by data. If the unit's duty (or operating level) were a major factor, there would be seasonality to the PM emissions data that would track the seasonal duty of the facility, which is definitely not the case. Peak quarters would be the same year to year. If coal variability were a major factor, as asserted by the commenters, changes in coal composition and the fPM rate would track together, which they don't. A closer look provides additional support for these points.

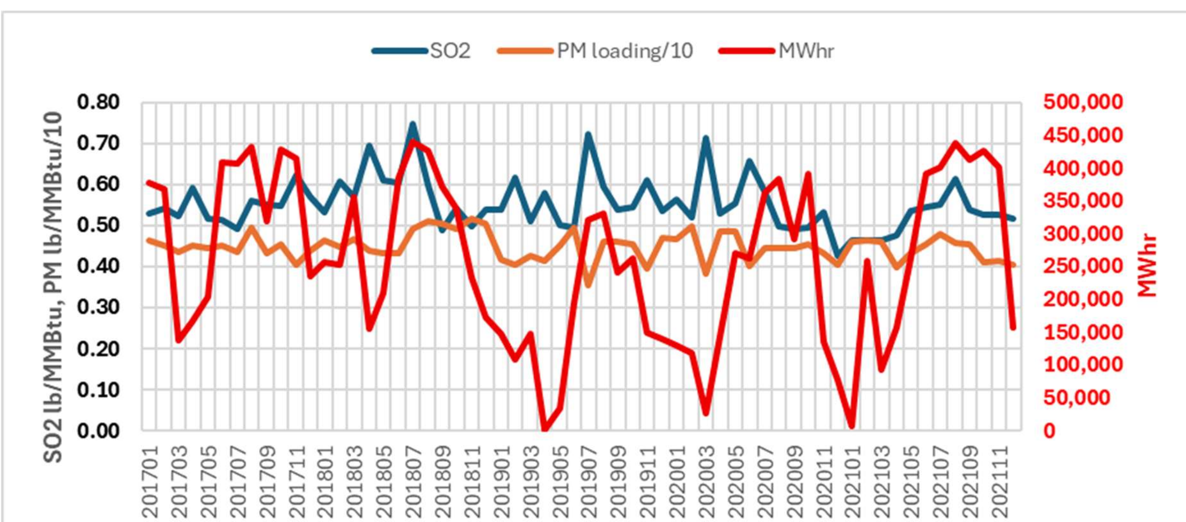
An examination of the Coronado coal data and operating data from EIA Form 923 over the same period does not explain the trends in Figure 1. Figure 2 shows monthly generation, PM loading (divided by 10 and assuming that 80% of coal ash becomes fly ash) and inferred SO_2.[20] Figure 2 displays patterns of seasonality in generation: peaks in generation are consistently in July-August, and first quarters (January-March) are consistently low load periods. This is inconsistent with the PM data of Figure 1, which shows no seasonal trend. The variability in fuel characteristics in Figure 2 also shows no relationship with the quarterly PM data in Figure 1. The only reasonable reason for the trend in PM emissions at Coronado is that operators waited several quarters, and in one case over two years, to take corrective measures to improve the emissions rate.

[19] Ibid. at 14

[20] PM loading and inferred SO2 were calculated from the average of reported fuel characteristics for deliveries in the month. For months without fuel deliveries, the average of the prior two months was used.

Figure 1. Coronado Generation Station PM emissions over 20 operating quarters (annotation added)[21]

Figure 2. Coronado Operating Data, SO_2, PM loading from coal, and generation (Developed from EIA Form 923)



[21] Ibid. at 13

Coronado data demonstrates that both a PM CEMS and lower emission limit are needed

Because the facility was equipped with PM CEMS, the facility was aware that the PM emissions were increasing over a two-year period. Therefore, even with a PM CEMS, without a lower emission limit, operators may permit emissions to drift higher than they could be. Thus, a lower emission limit is justified as well as a requirement to use PM CEMS.

PM emissions data is not evidence that current compliance methods are "appropriate and effective"

EPA further argues:

> *As noted earlier and in the 2024 Final Action, a large majority of sources have reported measured compliance data showing fPM emissions that are well below the previous fPM standard of 0.030 lb/MMBtu, which further illustrates that the various options for demonstrating compliance with the fPM standards have been appropriate and effective.* 90 Fed. Reg. at 25542.

A facility that reports emissions at a particular level using a PM CEMS is more reliably meeting that emission level than a facility that reports the same emission level using stack tests. Concluding that "*various options for demonstrating compliance with the fPM standards have been appropriate and effective"* because *"a large majority of sources have reported measured compliance data showing fPM emissions that are well below the previous fPM standard of 0.030 lb/MMBtu"* is not correct because it does not account for the relative effectiveness of the methods of demonstrating compliance. If quarterly stack tests are fine for PM, why not do the same for SO_2, NOx and mercury? The answer is that some methods for demonstrating compliance, like CEMS, are far more reliable in demonstrating compliance than others, and in the past EPA has consistently favored CEMS when they are reliable and cost effective. PM CEMS are the most reliable compliance demonstration method currently available. As EPA noted in the Technical Memo associated with the 2024 MATS Update,[22]

> *Continuous monitoring of fPM required in this rule provides several unquantifiable benefits, including greater certainty, accuracy, transparency, and granularity in fPM emissions information as compared to the intermittent stack testing that most affected sources employ.*

Also,

> *In addition to providing EGU owner/operators with the ability to quickly detect, identify, and correct potential control device or operational problems, CEMS provide greater accuracy and transparency regarding the actual emissions from the units, which provides benefits to regulators as well as other stakeholders such as communities near these sources.*

We agree. The advances in PM CEMS technology since the 2012 MATS rule make PM CEMS reasonable and cost effective for EPA to require under the provisions of Section 112(d), which requires updating regulations based upon new technical developments, as well as Section 114.

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

Finally, in the final rule issued in 2024, EPA justified a PM emission rate of 0.010 lb/MMBtu rather than 0.006 lb/MMBtu on the basis of concerns about quality assurance requirements for PM CEMS at the lower PM emission rate. This is discussed in more detail in a later paragraph. The concern EPA expressed was that PM CEMS are calibrated against multiple Method 5 tests, and lower emissions rates would require longer Method 5 testing. If EPA removes the PM CEMS requirement, EPA should therefore reconsider a PM emission rate below 0.010 lb/MMBtu. Alternatively, if EPA goes back to the 2012 MATS fPM standard, the cost of using PM CEMS will be reduced from what they have estimated, and EPA's argument for removing the PM CEMS requirement from the 2024 MATS update will have far less merit because the cost to calibrate them will be reduced.

Volume- and mass-based sample options retained

PM CEMS require calibration against multiple extractive fPM measurements using EPA Method 5. In light of the fact that many facilities are controlling fPM emissions to well below 0.030 lb/MMBtu, EPA decided in the 2024 MATS update rule to require extractive samples be conducted with a minimum sample volume or minimum sample mass in order to reduce measurement uncertainty. The intent was to ensure that an adequate sample was collected to provide a reliable indication of fPM emissions. EPA intends to keep both the minimum mass option as well as the minimum volume option.

In determining the fPM emission limit, EPA considered random error of measuring fPM emissions with a PM CEMS, and this became an important factor in EPA selecting the fPM emission rate of 0.010 lb/MMBtu. Table 2 summarizes EPA's analysis of the time duration to collect adequate sample to meet quality assurance requirements at various proposed emission levels. EPA ruled out emissions limits below 0.010 lb/MMBtu as a result of their concerns about the need to maintain measurement random error low enough to meet quality assurance requirements. At lower emission levels there is a need for longer sample times to achieve adequate sample to meet the quality assurance requirements. For example, EPA determined "that an emission level of 0.006 lb/MMBtu is ineligible for consideration because its random error contribution to measurement uncertainty for run durations of four hours is too high."

EPA's decision to maintain the minimum sample size or minimum volume criteria for sampling appears to be a reasonable approach, provided that facilities continue to control PM emissions to well below the limit. As previously noted, measuring to lower levels requires longer sample times and will result in greater testing cost. There is the possibility that maintaining the minimum sample mass requirement in combination with EPA's proposal to set a higher emission limit than in the 2024 MATS update might have the perverse effect of encouraging facilities that are currently controlling to well below 0.030 lb/MMBtu to increase their emission levels in order to reduce sample time. That is why maintaining the 2024 MATS update requirements is preferred.

Table 2. Summary of Appropriateness of PM CEMS Use for Compliance Determination at Various Emission Levels[23]

Emissions level, lb/MMBtu		Is the Reference Method Testing Random Error Component Appropriate?	Is the Expected PM CEMS QA Criteria Pass Rate Appropriate?	Are PM CEMS for Compliance Determination Appropriate at this Emission Level?
Base Case	0.030	Yes, for run durations of at least one hour	Yes	Yes
Proposed Levels	0.020	Yes, for run durations of at least 1.5 hours	Yes	Yes
	0.015	Yes, for run durations of at least two hours	Yes	Yes
	0.010 with QA criteria broadened to 0.015	Yes, for run durations of at least three hours	Yes	Yes
	0.010	Yes, for run durations of at least three hours	No	No
	0.006	No	No	No

The 1.2 lb/TBtu limit is achievable for all lignite units

Hg capture is driven by mass transfer and chemistry. Mass transfer relates to how effectively the Hg can come in contact with the material that is used to remove it, and it is often the most limiting factor. This is mostly limited by the configuration of the facility, and it is therefore costly to change. There are some improved activated carbon injection techniques or flue gas mixing methods; however, there are still limitations to what can be done based upon the configuration of the facility.

Chemistry also presents challenges because some forms of Hg are easier to capture than others, and there are some flue gas constituents that can interfere with capture. But, these chemistry challenges have been overcome with developments in activated carbons and chemical additives in the years since the 2012 MATS rule. These are explored in great detail in reports that I have prepared in the past and a prior declaration to the United States Court of Appeals for the District of Columbia Circuit, and these are included in this report by reference.[24] These reports, and particularly the Staudt Declaration 2024, address specific issues and comments by industry.

[23] Memo from Barrett Parker, US EPA, To Docket ID No: EPA-HQ-OAR-2018-0794, Subject: Suitability of PM CEMS Use for Compliance Determination for Various Emission Levels, January 20, 2024

[24] Staudt, J., *Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plant*s, for Center for Applied Environmental Law and Policy (CAELP), August 19, 2021, https://www.andovertechnology.com/wp-content/uploads/2021/08/PM-and-Hg-Controls_CAELP_20210819.pdf; hereafter, Staudt 2021

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, https://www.andovertechnology.com/wp-content/uploads/2023/01/C_22_CAELP_4_20230105-2.pdf; hereafter Staudt 2023

Staudt, J., Declaration as an Exhibit for Opposition to Environmental and Public Health Respondent-Intervenors to Petitioners' Motions for Stay, submitted to United States Court of Appeals for the District of Columbia Circuit, re: State of North Dakota, et. al, v. U.S. Environmental Protection Agency, et. al. submitted July

As I will demonstrate, the plant configurations for the lignite units are all very favorable for high Hg capture. And, any chemistry challenges that once were problematic and might have limited Hg capture at lignite units have been overcome.

The role of plant configuration

Perhaps the most important plant aspect that impacts potential mercury capture is plant configuration. The most difficult plant configuration is when a plant is equipped with an ESP as the only flue gas pollution control device. This is because in this situation Hg capture relies entirely upon in-flight capture of Hg on particulate matter, including any injected activated carbon. With in-flight capture, mass transfer is not as effective as the other available situations. The particle matter (with the Hg on it) must then be captured by the ESP. In fact, in this configuration some facilities are achieving over 95% Hg capture efficiency. About 15%-20% of pulverized coal facilities utilize this configuration.[25] However, no lignite units have this configuration. *Every lignite unit is configured in a manner where there is the potential for much higher Hg capture.* These configurations are:

- Baghouse (4 units)
- Baghouse or ESP combined with a wet scrubber (14 units)
- Baghouse in combination with a dry scrubber (4 units)

A baghouse enables extremely intimate contact between any fly ash or activated carbon and the Hg containing flue gas. The Hg is readily captured onto the fly ash or activated carbon due to the very intimate contact in the filter cake of the baghouse. *As a result, any facility with a baghouse is capable of extremely high Hg capture.*

Wet scrubbers are extremely effective at removing oxidized Hg because oxidized Hg is highly water soluble. Oxidizing agents, like bromine, or other chemicals may be easily added upstream (in the coal or flue gas) or into the scrubber to convert any elemental Hg to oxidized Hg and thereby effectuate Hg capture in the scrubber. Oxidizing agents, such as bromine, are very easily and inexpensively added to the flue gas by addition to the coal, as part of activated carbon or other means. Wet scrubber chemistry management has also proven to address any challenges that were problematic many years ago, such as “re-emission”. This is discussed in detail in Staudt 2021, Staudt 2023 and in Staudt Declaration 2024. These chemical treatments and operational controls have proven to be highly effective at a relatively low cost. Sometimes activated carbon is also added upstream and may be captured in an upstream PM control device. All of the lignite units with wet scrubbers have either an ESP or a baghouse for PM control. As a result, the combination of Hg removal in the PM control device with Hg removal in the wet scrubber can be very effective.

Dry scrubbers with baghouses can also capture Hg very effectively. These often require oxidizing agents because the dry scrubber may remove the chlorine, but such agents are readily added. Bromine may be introduced to the gas stream on the activated carbon or it may be added to the fuel before it is introduced to the furnace. The dry scrubber also removes SO_3, which improves the capture efficiency of the carbon additive, as discussed below. Capture of Hg using ACI is highly efficient with this configuration.

22, 2024, https://www.andovertechnology.com/wp-content/uploads/2024/07/Staudt-Declaration-final-072124.pdf, hereafter, Staudt declaration 2024

[25] Staudt 2023 at 34

As a result, every lignite unit is a configuration that is capable of high Hg capture efficiencies. By comparison, there are bituminous and subbituminous units that only have an ESP—a more challenging configuration—and that are nonetheless maintaining below 1.2 lb/TBtu.

The role of chemistry

Chemistry is determined by the coal type and any chemicals introduced into the flue gas. Lignite coal has higher sulfur than subbituminous coals, but typically lower sulfur than bituminous coals. Lignite coal is also mine mouth, which is to say that a plant is built at the coal mine and the lignite coal is exclusively used at that plant. Lignite plants, therefore, do not receive coal from other mines. Chemical factors that impact Hg capture include:

- Hg content and form – Lignite coal Hg content is normally higher than that of subbituminous coals and *most*, *but not all,* bituminous coals. EPA also claimed that it is variable. Hg that is in the form of oxidized Hg is generally easier to capture than elemental Hg. Although lignite coals typically result in a greater proportion of Hg being in the elemental form than the oxidized form, that is readily remedied, as will be discussed below. And, as will be demonstrated with data from the Conemaugh plant, Hg content and variability for lignite coals are often less than for some bituminous coals where 1.2 lb/TBtu is already being achieved as it is the applicable emission limit for plants firing non-lignite coal.
- SO_3 content in the flue gas – SO_3, which is the result of oxidation of coal sulfur, can interfere to a degree with capture using activated carbon. This is also impacted by alkalinity, because highly alkaline fly ash will remove SO_3 as well as halogens.
- Halogen content – Oxidized Hg is easier to capture than elemental Hg. The presence of halogens (bromine, chlorine, etc.) in the coal impacts the presence of oxidized Hg, with more halogens resulting in more oxidized Hg. Alkalinity can also impact halogen content. Halogens can be added, as will be discussed below, to increase the proportion of Hg that is in the oxidized form.

Coal variability - In a Motion to Stay the 2024 MATS rule, several declarations were submitted. One of the declarations includes attachments. One of the attachments addresses a number of concerns relating to lignite coal. [26] These concerns are addressed in more detail in Staudt Declaration 2024.[27] One of those concerns is lignite coal variability, particularly variability in Hg content, but also other factors as well. As I demonstrate in that declaration, the argument presented in that attachment combined data from 60 different lignite mines and 40 PRB mines, which makes it unrepresentative for any given plant. Lignite coal plants are mine-mouth, and therefore only receive coal from the local mine. *As I will demonstrate, for any facility, the variability in coal properties (Hg content in particular, but also sulfur) is relatively small, and significantly less than for bituminous plants that receive coal from multiple mines*.

Low halogen content - Low halogen content has been found to be easy to address. Lignite as well as subbituminous coals are often low in halogen content. Several lignite fueled plants used refined coal through 2021, which included some form of halogen in the coal that would increase the presence of oxidized Hg. Addition of halogens has proven to be very easy. Like adding salt to flavor food to taste, if needed, adding halogens to flue gas is easy and inexpensive to do. It can

[26] North Dakota v. EPA, No. 24-1119, Amended Motion for Stay (D.C. Cir., June 7, 2024). 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").

[27] See Staudt Declaration 2024, paragraphs 45-66

be added to the coal, added to activated carbon, or added through other means. The level of halogen addition will impact Hg oxidation, which will then impact Hg capture from ACI or in a downstream wet scrubber. *Therefore, even if lignite plants have low halogen content, adding halogen is a very easy and inexpensive solution*.

SO_3 content - SO_3 has principally been a problem for units equipped with only an ESP because of the limited options for control (they must rely entirely on in-flight capture and collection of PM in the ESP), and it is therefore less of a problem for lignite units than for bituminous units with only an ESP or Powder River Basin fueled units with only an ESP using SO_3 conditioning. Addressing this SO_3 issue required development of sulfur-tolerant activated carbons. These were developed in the time since the 2012 MATS rule, as described in more detail in Staudt 2021 and Staudt Declaration 2024. These have enabled bituminous coal units equipped with only an ESP, or PRB fueled units equipped with an ESP and SO_3 flue gas conditioning, to achieve under 1.2 lb/MMBtu without addition of a baghouse or a scrubber. While the impact of SO_3 on lignite units should not be ignored, it certainly is not as big of an issue for lignite units as for some units firing other types of coal because all lignite units have very favorable plant configurations – such as baghouses or combinations of PM control with scrubbers. *And, as with units firing other types of coal, lignite units can address any issues with SO_3 by using sulfur-tolerant activated carbons.*

Alkalinity - Alkalinity mostly impacts SO_3 (lowering it, which helps with Hg capture), and to a lesser extent, also impacts halogens. Lignite coal, like PRB coal, tends to be higher in alkalinity than most bituminous coals. As noted, halogens are easy to add. In some cases, trona, a sodium compound, can adversely impact Hg capture if added to flue gas. But none of the lignite units inject trona, or would have a reason to. *So, in the case of lignite units, alkalinity does not introduce any problems that are not easily addressed.*

Achievability of 1.2 lb/TBtu standard for range of boiler types

EPA acknowledges that configuration has a significant impact when describing why the Twin Oaks (aka, Major Oaks) and the Red Hills plants have high capture efficiency. EPA states that, as CFB boilers, these facilities have good configurations for Hg capture. However, there is an additional reason that these plants are highly effective at Hg capture. They both have baghouses. Indeed, any carbon in the fly ash will capture the Hg quite effectively in the baghouse, perhaps even without the addition of activated carbon. So, the baghouse plays an important role in improving the effectiveness of capturing Hg. While both facilities are equipped with ACI, and would have very low SO_3 present in the flue gas due to high free lime content, the presence of a baghouse makes the ACI as well as any intrinsic capture on fly ash much more effective. If the PM control equipment on these units was an ESP, the Hg capture would be much more difficult. So, the combination of a CFB and a baghouse results in very high intrinsic Hg capture.

Lignite plants equipped with baghouses include: Antelope Valley, Coyote, Spiritwood, Major Oak, Oak Grove, and Red Hills. Some of these also have an upstream dry scrubber (Antelope Valley, Coyote, Spiritwood), which also helps to make the Hg capture with ACI even more effective. Oak Grove has a wet FGD downstream of the baghouse, which provides the option to reduce Hg further.

A dry scrubber upstream of a baghouse allows extremely effective capture in the baghouse with ACI because any SO_3 that might interfere with the Hg capture from activated carbon is removed.

A wet FGD will enable additional Hg capture beyond what is achieved with ACI because a wet FGD will remove oxidized Hg very efficiently.

The remainder of the lignite plants (Coal Creek, Leland Olds, Milton R Young, Limestone, Martin Lake, and San Miguel) have ESPs followed by a wet FGD. This is also a highly effective means of controlling Hg. As noted, a wet FGD removes oxidized Hg very effectively. I will demonstrate how a facility with an ESP and wet FGD is capable of very high Hg capture.

Why don't all lignite units already achieve much lower than 4 lb/TBtu, like Red Hills and Major Oak?

As noted, Red Hills and Major Oak are CFBs with baghouses. CFBs, as noted by EPA, tend to have high unburned carbon in fly ash. There is also high free lime in the fly ash. That unburned fly ash, in combination with a baghouse, results in very high intrinsic Hg capture. The units are equipped with ACI, but it may be possible that carbon injection is not necessary in light of the carbon that is already in the fly ash.

The other lignite coal configurations – all pulverized coal boilers - may not produce as much *intrinsic* capture and may rely to a greater degree upon ACI or scrubber additives. ACI and chemical additives behave as "dial up" technologies, where Hg capture can be increased with additional carbon or additive. There is no motivation to go far below the limit. As noted in EPA's technical memo with the 2024 rule,[28] additional Hg capture can be achieved with greater activated carbon injection. Alternatively or in combination with ACI, addition of other chemicals can improve Hg capture.

The Conemaugh plant in Pennsylvania demonstrates that high capture efficiency is possible for lignite plants with pulverized coal boilers.

As noted earlier, Hg capture is related to plant configuration and chemistry, and it is possible to examine a bituminous facility that has very high Hg content (similar to lignite coals) and higher sulfur than most lignite coals that consistently achieves under 1.2 lb/MMBtu.

The Conemaugh power plant in Pennsylvania is a pulverized coal power plant, which is equipped with ESPs and wet FGD and burns bituminous coal that is just as difficult for Hg control, if not more so, than any of the lignite coals. The Hg content is high and it is also variable, as is the sulfur content. Using EIA Form 923 data, it is possible to infer the effective SO_2 rate of the coal (assuming nearly all of the coal sulfur converts to SO_2) and determine the Hg content of the coals burned at the Conemaugh power plant. SO_2 rate is important since SO_3 impacts Hg capture from ACI and SO_3 in the flue gas is roughly 1-2% or so of the inferred SO_2 rate. There was also an extremely wide range of Hg content of the coals burned at the Conemaugh plant over the years. Therefore, these coals were often both high in Hg content and highly variable – and, as will be demonstrated, Conemaugh experienced far more variability in Hg content in its coals than any lignite plants where coal Hg data was available.

Figure 3 shows average inferred SO_2 rate (equal weighted average SO_2 of each coal delivery), the standard deviation of those inferred SO_2 rates, and the heat input weighted average inferred SO_2 rate (average weighted according to reported heat input of coals over the year).

Figure 4 shows average Hg content (equal weighted average of Hg for each coal delivery), the standard deviation of those Hg contents, and the heat input weighted average Hg content (weighted average according to reported coal heat input over the year). The high standard

[28] 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, pp 40-41

deviations of the Hg content and inferred SO_2 rate demonstrate that the coals are highly variable in chemical composition, which makes it more challenging to "tune" a control system.

Figure 3. Inferred SO_2 rate (lb/MMBtu) of Conemaugh Plant coal (developed from EIA Form 923)[29]

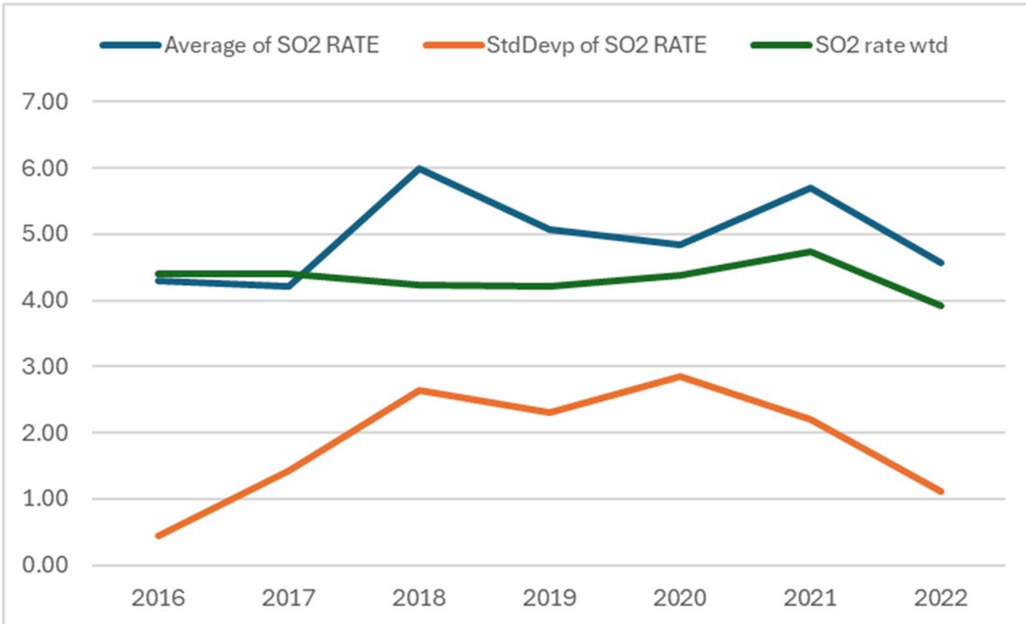
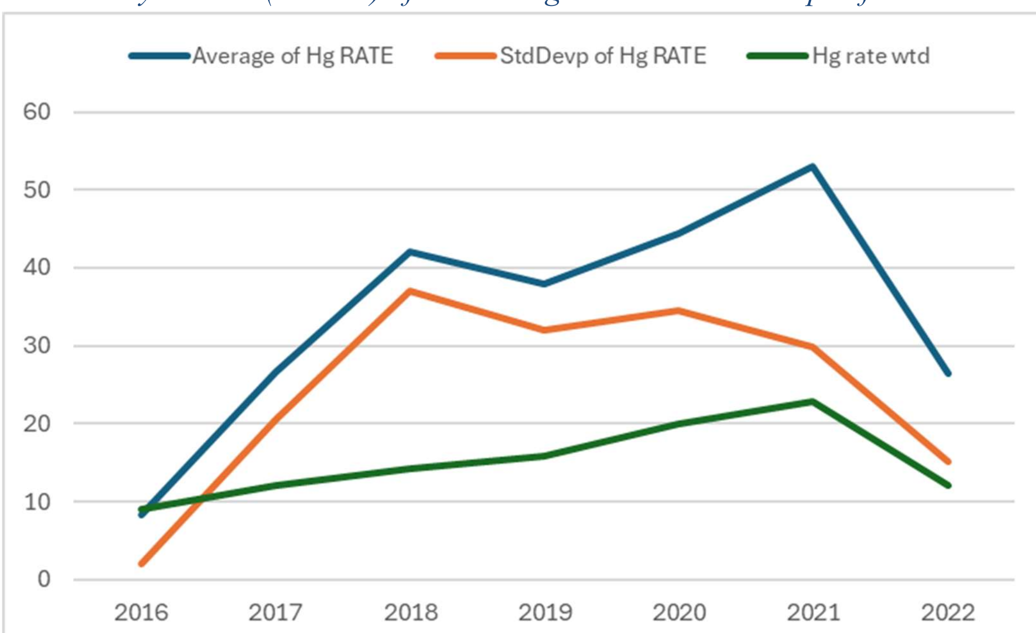


Figure 4. Mercury content (lb/TBtu) of Conemaugh Plant coal developed from EIA Form 923)[30]



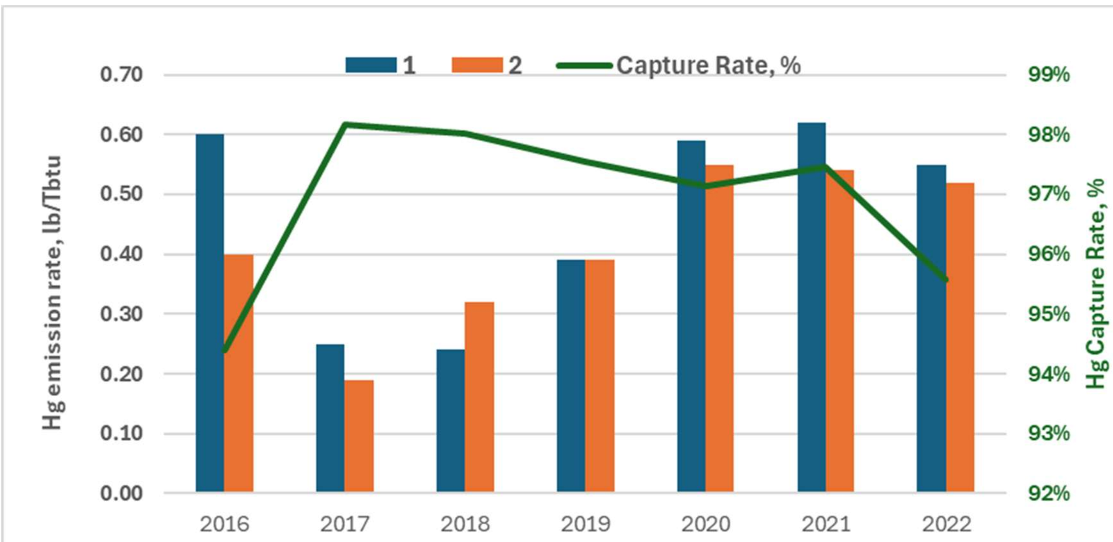
Using the heat input weighted average Hg rate and the reported Hg emission rates, it is possible to determine the capture efficiency at the plant. The Conemaugh plant has consistently

[29] Inferred SO_2 rate determined by reported heating value of the fuel and the sulfur content in percent.

[30] Hg content determined by reported heating value of the fuel and the Hg content in ppm. The 2016 reported Hg content appears unreliable since all of the reported contents were either 0.1 or 0.2 ppm.

burned high Hg and high sulfur coal that is typical of western PA coals and has also consistently maintained its emissions well under 1.2 lb/MMBtu, as demonstrated in Figure 5. In any year Conemaugh receives coals from several different mines. As shown, the variability in Hg content (standard deviation) far exceeded even the heat input weighted average. Some Conemaugh coals had Hg content in excess of 100 lb/TBtu. Except in 2016, calculated capture efficiency has exceeded 95% in every year. As noted in the footnote accompanying Figure 4, the coal mercury data for 2016 appears unreliable. So, it is very likely that the capture efficiency was actually above 95% that year.

Figure 5. Annual average Hg emissions of the Conemaugh plant units 1 and 2 and average Hg capture, 2016-2022 (From EIA Form 923)



Coal variability also impacts the ease with which control equipment can be "tuned" to control emissions. Figure 6 compares the Hg content of lignite plant coals (and the standard deviation of that content) to that of the Conemaugh plant. All data is for the year 2020. The standard deviation shows the variability of Hg content of the coal. As shown in Figure 6, not only is the Hg content lower for most lignite plants, the standard deviation is also very low for lignite plants compared to the coal used at the Conemaugh plant. In fact, the variability in Hg content, as measured by the standard deviation of Hg content, for the Conemaugh plant coal exceeds the weighted average of the Hg content.[31] This is because, unlike most other coal units, lignite units are mine-mouth, and receive coal from only one mine. Most bituminous and subbituminous units receive coal from multiple mines, and therefore face much greater variability in coal. Thus, mercury content variability is much less for lignite units than for the Conemaugh plant, and likely less than for most non-lignite units that fire coal from a range of mines. This illustrates how lignite plants are fully capable of mitigating variability issues that other types of plants with greater variability have successfully addressed, as evidenced by the Conemaugh plant consistently achieving mercury capture rates exceeding 95%.

Sulfur content also is more variable at Conemaugh than at any of the lignite-fired plants. As demonstrated in Figure 7, Conemaugh has significantly higher inferred SO_2 levels than any lignite plant other than San Miguel, and has much higher variability, as indicated by the standard

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[31] The weighted average (weighted by heat input) for Conemaugh is 19.8 lb/TBtu, while a simple average of all of the fuels was 44 lb/TBtu and standard deviation was 34.5 lb/TBtu.

deviation in inferred SO_2, than any lignite fueled unit. In fact, San Miguel and Conemaugh have very similar configurations (ESP followed by a wet scrubber).

Figure 6. Average Hg content and standard deviation of Hg content for different lignite plant coals and for the Conemaugh plant during 2020.

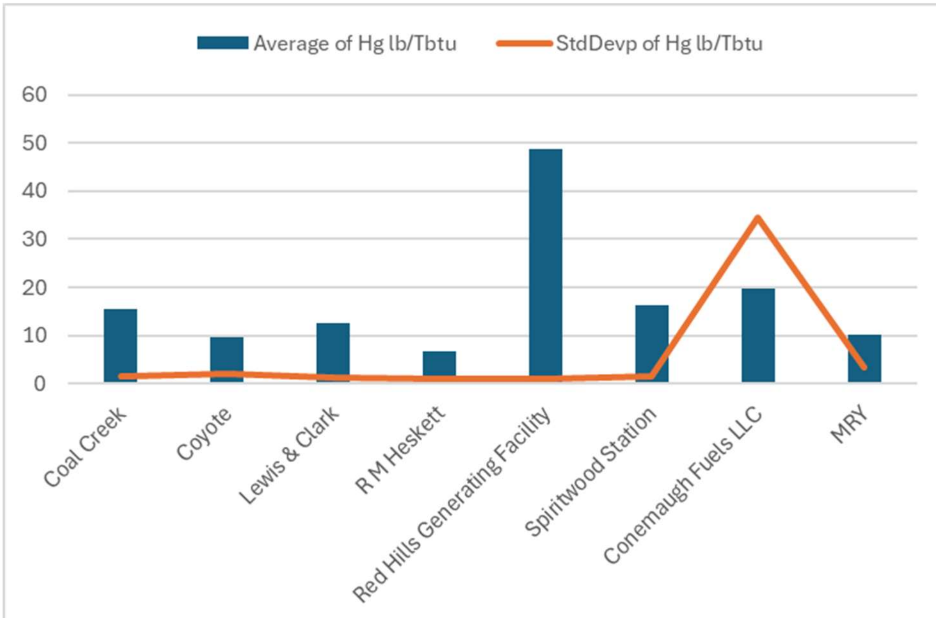
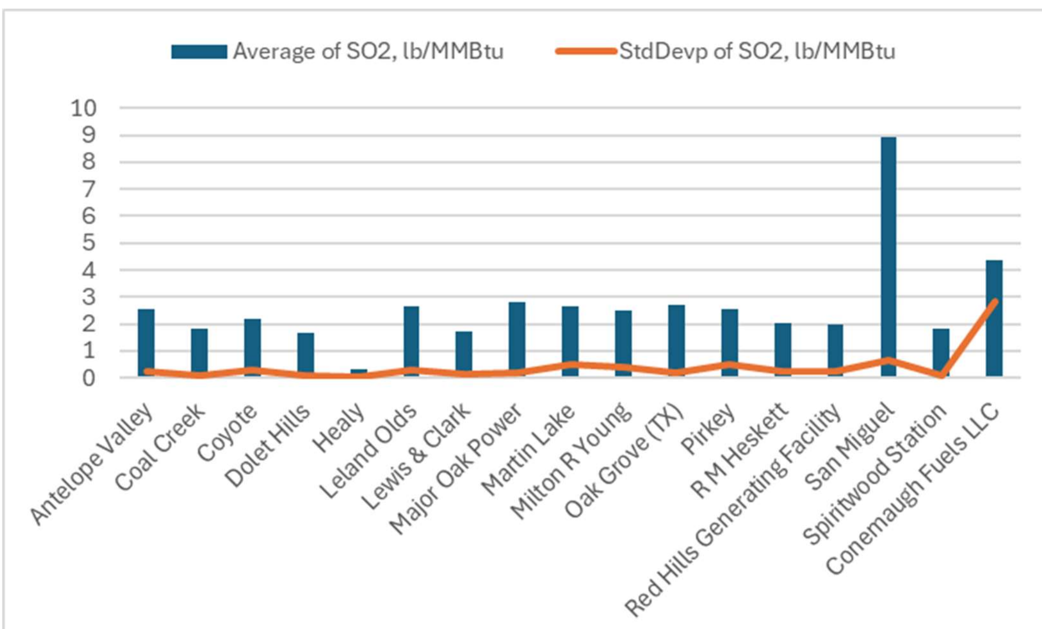


Figure 7. Comparison of SO_2 for different plants



Consideration of ACI system modification costs

EPA claims that the 2024 update rule did not factor the costs of any modifications or testing in the cost of compliance. All facilities are equipped with ACI. The only modifications, if any, will be to address increases in ACI flowrate, if necessary. These will be extremely modest, and at most may involve an increase in activated carbon storage capacity, which can alternatively be addressed with more frequent deliveries of activated carbon. Changes in sorbent metering valves would be a relatively minor change. There would be some degree of testing to arrive at new control setpoints, but this again is a very low cost and could be done by plant staff. ATP estimated these additional one-time costs for modifications or testing to be at most about $5/kW, which might be on the order of the cost of the increase in carbon usage for one year.

By far, the greatest cost would be any increase in activated carbon used, or any additive chemicals needed on an ongoing basis. In the technical memo associated with the MATS update rule, EPA did address the single greatest cost – the increased use of brominated activated carbon. The example provided in the technical memo, in my opinion, is a worst-case scenario, and overestimates the cost for most facilities. First, it assumes a Hg content of 25 lb/TBtu. As shown in Figure 6, the concentration of Hg is well below 25 lb/TBtu for the North Dakota Lignite units. EPA's Technical Memorandum with the rule[32] showed about 25 lb/TBtu for the Texas and Mississippi lignite units. The ACI injection rates assumed are consistent with the rate for an ESP equipped unit. For units with a baghouse, injection rates will be significantly lower, perhaps half. For the ESP equipped facilities with wet FGD systems, much of the Hg capture can be achieved in the wet scrubber if bromine is added to oxidize the Hg, lessening the incremental carbon needed for plants in this configuration as well.

EPA's claims regarding the San Miguel plant

EPA claims that the 2024 update rule didn't analyze higher Hg content at plants like San Miguel (34 lb/TBtu) that would need to achieve 96.3% capture efficiency. 90 Fed. Reg. at 25544. Analysis of the Conemaugh plant demonstrates that well over 96.3% capture efficiency has been achieved over a several year period (2017- 2021) at a facility with an ESP and a wet scrubber – the same configuration that is being deployed at San Miguel. In fact, Conemaugh is not alone in achieving high capture efficiencies. Staudt 2021[33] shows that the top 30% of all non-lignite units achieved an estimated 96% or higher capture efficiency, with the top decile averaging 98.7% capture efficiency. The top decile (39 units) even included a unit with only an ESP for flue gas emission control equipment, the most challenging configuration possible. Top decile coals were more likely to be bituminous coals than any other type. Bituminous coals are also likely to have higher SO_2 content than lignite coals, making Hg capture more challenging because of the higher SO_3 content. While San Miguel, like Conemaugh, has high SO_2 content (and presumably high SO_3 content), this is less of an issue at a facility with a wet scrubber, which can take advantage of oxidation of Hg and effective capture in the wet scrubber. Many bituminous units have this configuration. High SO_3 is more of a concern for unscrubbed units with an ESP, and no lignite units have that configuration.

Therefore, a careful evaluation of facility configuration and chemistry indicates that the San Miguel plant is capable of achieving in excess of 96.3% capture efficiency and compliance with the finalized 2024 MATS update rule. All lignite units are capable of complying with the 1.2 lb/TBtu standard because most require less than 96.3% capture efficiency. Most of the ND lignite units only require about 90% capture. According to Staudt 2021[34], *the top eight deciles of non-lignite units all achieve a capture efficiency of 90% or greater*.

[32] 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 (hereafter, 2024 Technical Memo), Docket ID. No: EPA-HQ-OAR-2018-0794, January 2024., Table 10

[33] Staudt 2021 at pages 54-55

[34] Ibid

Technical developments now address lignite compositional differences

EPA claimed that it didn't consider the precise combination of both low halogen and high sulfur content in the 2024 Rule. In fact, EPA did. As noted, EPA was well aware that halogen is readily addressed with halogenated activated carbon or through addition of bromine. This is demonstrated in Table 8 of EPA's 2024 Technical Memo. As noted in pages 37-38 of that memo, control technologies have been developed to introduce halogens to the flue gas.

EPA also discusses concerns with high sulfur content in the 2024 Technical Memo:

> *[A]s explained in the final preamble for this rulemaking, numerous control technology vendors and developers have introduced "sulfur tolerant" sorbents and other control technologies to address this concern. And EGUs firing bituminous coals are much more prone to produce SO3 than those firing lignite (due to the higher levels of sulfur in most bituminous coals and the presence of SCR systems for NOx control, which are uncommon with lignite-fired EGUs in the U.S.).*

Therefore, EPA recognized that, as a result of technical developments, halogen content and sulfur content have been addressed. In fact, the challenge of sulfur is most difficult for bituminous coals that are only equipped with an ESP or subbituminous units that have an ESP and SO_3 flue gas conditioning, and this has been overcome. Several of these facilities exist and have demonstrated compliance with the 1.2 lb/MMBtu standard. Moreover, halogen addition does not interfere with, and in fact enhances, the performance of sulfur tolerant carbons.

In fact, when comparing lignite coals to coals in western Pennsylvania and perhaps some other eastern bituminous coals used at plants that currently achieve under 1.2 lb/TBtu, the Hg content and sulfur content of lignite coal does not particularly stand out. As previously noted, halogens are easily and inexpensively addressed. Therefore, control of Hg to 1.2 lb/TBtu on lignite units is no more difficult than control of Hg to 1.2 lb/TBtu on many bituminous coals. All of the chemical properties have been addressed.

EPA's claim that its 2021 Section 114 information request is not representative of emissions on a rolling 30-day basis is not meaningful

EPA asserts in footnote 20 that:

> *In May 2021, the EPA issued a CAA section 114 request to lignite facilities for Hg emissions and related operational information. The request designated specific time periods which were not representative of emissions achievable on a 30-day rolling basis.* 90 Fed. Reg. at 25,543 n.20

It is important to note that the 2012 MATS rule was developed with far less data than is available today or was requested in that Section 114 request for the affected coal units. In fact, all of the affected lignite units, like bituminous and subbituminous units, are equipped with Hg CEMS that provide a detailed picture of emissions performance. Also, several of the affected plants have been submitting coal Hg data that is available on EIA Form 923, which was not being submitted prior to the 2012 MATS. The combined data – Hg emissions data from Hg CEMS – as well as data on the Hg content of lignite as well as other coals, is sufficient to establish that the revised limit is achievable for all lignite units.

Subbituminous and bituminous fueled units have consistently demonstrated compliance with the 1.2 lb/TBtu limit in the 2012 MATS rule. This is despite the fact that, when that 2012 rule was being developed, there was far less Hg emissions data, less coal Hg data, less experience controlling Hg, and less understanding of the science of controlling Hg than exists today. When the 2024 Technical Memo was prepared, EPA was working with significantly more technical data than was available to it at the time that the 2012 MATS rule was developed, and more information on mercury emissions than available to EPA from the 2021 information request. As I have demonstrated in this report, analysis of the technical issues – plant configuration as well as chemistry - clearly demonstrates that all lignite units are capable of meeting the 1.2 lb/MMBtu emission limit of the 2024 MATS update rule.