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America's Power Comments on
EPA's Proposal to Revise the Mercury and Air Toxics Standards

America's Power submits the following comments on EPA's proposed changes to the National Emission Standards for Hazardous Air Pollutants for coal- and oil-fired electric generating units (EGUs), commonly known as Mercury and Air Toxics Standards (MATS).[1] The proposed changes include a more stringent filterable particulate matter (fPM) standard for all coal-fired EGUs and a more stringent mercury standard for lignite-fired EGUs. As we explain in our comments, the changes proposed by EPA are not necessary; they are based on an improper analysis of data; and they are inconsistent with the Clean Air Act (CAA).

America's Power is the only national trade organization whose sole mission is to advocate at the federal and state levels on behalf of coal-fired electricity, the nation's coal-fired electric generating fleet, and the supply chain that supports the coal fleet. Our membership is composed of electricity generators, coal producers, barge operators, and equipment manufacturers. The coal fleet provides reliable, dependable, and affordable electricity. Also, coal-fired EGUs are a fuel-secure source of electricity, which has become increasingly important because of extreme weather.

EPA's proposed changes will increase compliance costs, raise electricity prices, and could lead to additional retirements of coal-fired EGUs. Already, utilities have announced plans to retire 40 percent of the existing coal fleet by 2030. Other EPA rules, especially the recently proposed Carbon Rule, will accelerate coal retirements, even though grid experts have issued warnings about the potential for power shortages because of the retirement of coal-fired generation and other dispatchable electricity resources.

Our comments explain why EPA should not tighten the fPM standard for coal-fired EGUs or the mercury standard for EGUs burning lignite. The proposed rule has failed to establish the technical foundation necessary for tightening the standards in both cases. Furthermore, the additional emission controls proposed by EPA would provide

[1] *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24,854 (Apr. 24, 2023).

minimal air quality benefits that are not necessary for to protect public welfare and the environment as required under the CAA.

Tightening the standards is not necessary to address residual risk.

Section 112(f)(2) of the CAA directs EPA to assess the remaining residual public health and environmental risks posed by hazardous air pollutants (HAPs) emitted from the EGU source category. Further regulation under MATS is required only if that residual risk assessment demonstrates that a tightening of the current HAP emission limitations is necessary to protect public health with an ample margin of safety or protect against adverse environmental effects.

America's Power agrees with EPA's proposed determination that further regulation of mercury and other HAPs is unnecessary to address any remaining residual risk from any affected EGU within the source category. The stringent standards based on state-of-the-art control technologies that are currently imposed on coal-fired EGUs have already achieved significant reductions in HAP emissions. As EPA itself noted, the MATS rule has achieved steep reductions in HAP emission levels since 2010, including a 90 percent reduction in mercury, 96 percent reduction in acid gas HAPs, and an 81 percent reduction in non-mercury metal HAPs.[2]

Moreover, EPA has performed a comprehensive and detailed risk assessment that clearly documents the negligible remaining residual risks posed by the very low amount of HAPs now being emitted by coal-fired EGUs. EPA first performed that risk assessment in 2020, which concluded that "both the actual and allowable inhalation cancer risks to the individual most exposed were below 100-in-1 million, which is the presumptive limit of acceptability" for protecting public health with an adequate margin of safety.[3] Similarly, EPA's assessment supported the conclusion that residual risks of HAP emissions from the EGU source category were "acceptable" for other potential public health effects, including both chronic and acute non-cancer effects.[4]

These conclusions have been confirmed by the detailed reevaluation of the 2020 risk assessment that the Agency is now completing as part of the current rulemaking. That EPA reevaluation clearly demonstrates that the 2020 risk assessment did not contain any significant methodological or factual errors that could call into question the results and conclusions reached in the 2020 risk assessment. Most notably, EPA used accepted approaches and methodologies for performing a residual risk analysis that adhere to the requirements of the statute and are consistent with prior residual risk assessments performed by EPA over the years for other industry sectors.[5]

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[2] Fact Sheet, *EPA's Proposal to Strengthen and Update the Mercury and Air Toxics Standards for Power Plants, available* [here](#).

[3] 88 Fed. Reg. at 24,865.

[4] *Id.* at 24,865-66.

[5] 88 Fed. Reg. at 24,865. And finally, the HAP emissions from the EGU source category will further decline over the next five to ten years as the electric power sector continues to retire or reduce the utilization of coal-fired generating capacity and transitions to other energy resources. This transition means that HAP emissions from the electric power sector will continue to decline further and reduce the potential impacts of the remaining HAP emissions.

The results from both residual risk assessments provide a strong scientific foundation for EPA to conclude that the current MATS limitations provide an ample margin of safety to protect public health in accordance with CAA section 112(f)(2).[6]

The rulemaking record is insufficient to support tightening the fPM standard.

EPA has failed to develop the necessary technical foundation for justifying the proposed revision of the fPM standard, particularly since the proposal would lower the current standard by two-thirds from 0.030 pounds per million British thermal units of heat input (lb/MMBtu) to 0.010 lb/MMBtu.

No new control technologies. One deficiency in the technical analysis is that the Agency has been unable to identify any new fPM control technology that has been developed since the adoption of current fPM technology in 2012. Both the prior 2020 technology review and EPA's current revaluation "did not identify" any such new technology developments or advances.[7] Instead, EPA simply concluded in both cases that the "PM air pollution control device technologies that are currently in use are well-established and provide the capture efficiencies necessary" for meeting the current fPM limitations under the MATS rule.[8]

Cherry-picking emissions data. Another major problem with EPA's proposal is that the analysis is based on a limited set of emissions data that does not accurately capture the actual fPM reduction levels that can be achieved by available control technologies under the full range operating conditions at coal-fired EGUs. EPA's reliance on this unrepresentative emissions data greatly undermines, if not entirely invalidates, the technical analysis that EPA used to justify its decision to tighten the fPM standard.

This cherry picking of unrepresentative emissions data is reflected by the truncated review of the available fPM emissions data used to evaluate the performance of existing fPM control technologies. As discussed in the attached technical report,[9] EPA used fPM emissions data from just three years (2017, 2019, and 2021) even though the Agency had data going back over a decade starting at the time the MATS rule took effect in 2012. Moreover, EPA then further biased its data review by using fPM data from only two of the twelve quarters of data from the three years.

Since only one stack test is typically performed in each quarter, this means EPA is effectively using just two data points for each coal-fired EGU for evaluating the fPM performance levels of existing control levels at that unit. Moreover, EPA further arbitrarily skewed the limited fPM data set by selecting the two quarters of the emissions data having the lowest fPM emission rates. This limited and biased data set fails to reflect the operating profile of the unit, which will fluctuate due to variability in the composition of the coal, seasonal load fluctuations, and various

[6] America's Power also agrees that EPA correctly concluded that the current performance standards for other HAPs (such as acid gases and organic HAPs) should not be revised. If the Agency elects to change course and consider revising any of these HAP performance standards (which EPA should not do), the Agency must initiate a separate rulemaking or supplemental rulemaking that provides the opportunity for comment.
[7] 88 Fed. Reg. at 24,867.
[8] *Id.* (citation omitted).
[9] Cite to technical report.

other operating or processing conditions that could greatly affect the fPM control levels. The basis for emission levels under the proposal is maximum achievable control technology (MACT) and while standards based on MACT consider the best performing sources, the standard must be set at a level that is achievable by all sources, which requires a full evaluation of all available data.

Inaccurate cost estimates. A third major problem with EPA's technical analysis is the inaccurate cost estimates used for justifying the tightening of the current fPM limitation. This problem stems from the unrealistically low cost estimates that EPA has developed for major upgrades to existing electrostatic precipitators (ESP). As indicated in the attached technical report, the Agency significantly underestimated the fPM control costs by ignoring actual costs that electric utilities have incurred for major ESP upgrades.

If more realistic actual ESP upgrade costs were reflected in the EPA analysis, the average capital costs for ESP rebuilds would have significantly increased from $87/kW to $133/kW. As a consequence of underpredicting capital costs, EPA also significantly underestimated the dollars-per-ton removal cost for fPM. EPA's estimated removal costs ranged from $12,200 to $14,700 per ton of fPM, which is just one quarter of the average removal costs of over $47,000 per ton based on the average actual costs using realistic inputs. The imposition of control costs exceeding $47,000 per ton further argues against lowering the fPM limitation.

In conclusion, these fundamental problems—both individually and in combination—invalidate the technical basis underlying EPA's proposal to lower the fPM performance standard. The lack of such a technical foundation is especially troubling given that EPA itself has also expressly determined that fPM emissions from EGUs are not posing a residual risk to public health and the environment.

The more stringent alternative fPM standard lacks technical merit and could have adverse electric reliability repercussions.

EPA also is seeking comment on the adoption of a "more stringent alternative" regulatory scenario that would further lower the fPM emission limitation from 0.010 lb/MMBtu to 0.0060 lb/MMBtu. America's Power strongly opposes the Agency's adoption of this alternative option.

First, EPA already lacks a technical foundation for the proposed tightening of the current fPM emission limitation to 0.010 lb/MMBtu discussed above. Those same technical problems would also apply if EPA were to adopt a performance standard that requires coal-fired EGUs to further lower fPM emissions to 0.0060 lb/MMBtu.

Second, this additional incremental level of control is not only unnecessary to protect public health and the environment, but it would also force many EGUs to make either major upgrades to their baghouses or install new baghouses. The imposition of these additional unnecessary fPM controls would likely result in the premature retirement of coal-fired capacity and further increase the potential risks to grid reliability.

EPA itself estimates that 22,700 MW of coal-fired generating capacity would need to implement additional control measures in order to meet the more stringent fPM limitation of 0.0060 lb/MMBtu. Of this generating capacity, 11,300 MW would undertake major upgrades to the baghouse or install new baghouses, while another 12,200 MW of coal-fired generating capacity would retire by 2028.

The projected compliance costs of this more stringent alternative are also much greater than the total compliance costs projected for complying with the limitations under the proposal. According to EPA, the present value of the compliance costs for meeting the more stringent fPM limitation is projected to increase by $4.27 billion over the 2028-2037 period—specifically, increasing from $330 million to $4.6 billion. A substantial increase of $502 million would also result in the equivalent annual value of those costs—specifically, increasing from $38 million to $540 million.[10]

In short, the more stringent alternative poses significant risks to electric reliability. In addition to EPA's projections that 12,200 MW of coal-fired capacity would retire by 2028, another 11,300 MW of generating capacity would be at risk of early retirement within the same timeframe due to the major capital and operating costs they would incur for upgrading existing baghouses or installing new baghouses.

The rulemaking record is insufficient to support tightening the mercury standard for EGUs burning lignite.

EPA is proposing that EGUs burning lignite must comply with the same mercury emission limitation that currently applies to EGUs combusting bituminous and subbituminous coals, which is 1.2 pounds per trillion British thermal units of heat input (lb/TBtu). EPA's proposal is a substantial lowering of the current mercury limitation for lignite-fired EGUs, which is 4.0 lb/TBtu.

EPA failed to develop the necessary technical foundation to justify the proposed tightening of the mercury standard for lignite-fired EGUs. The core flaw in EPA's technical analysis is the incorrect assumption that lignite and subbituminous coals are substantially similar for purposes of controlling mercury emissions. According to EPA, the similar composition of the two coals supports the conclusion that control technologies now being used for meeting the current mercury limitation of 1.2 lb/TBtu for units combusting subbituminous coal are equally effective for controlling mercury emissions from units burning lignite. The attached technical report explains why this assumption is incorrect.

First, EPA fails to recognize the major differences between subbituminous and lignite coals. While both coals contain smaller amounts of sulfur than bituminous coal, the Agency's analysis fails to account for the higher amounts and variability of the mercury in lignite as compared to subbituminous coal. When, for example, accounting for the higher levels of mercury in lignite from North Dakota and Texas, mercury removal levels in excess of 90 percent are necessary to meet the proposed mercury limitation of 1.2 lb/TBtu. As noted below, achieving 90 percent mercury removal by units burning these lignite coals is considerably more difficult to achieve than the mercury removal levels achievable with subbituminous coal.

Second, the differences in coal composition (specifically, the variability in mercury when combined with the sulfur and alkalinity of inorganic matter) affect the

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[10] These projected compliance costs are based on a discount rate of three percent. At a seven percent discount rate, EPA estimates the present value of the compliance costs to be $3.4 billion, with an equivalent annual value of $490 million.

effectiveness of existing control technologies and measures for reducing mercury emissions from EGUs burning lignite. For example, EPA incorrectly concludes that lignite-fueled units can meet a mercury limit of 1.2 lb/TBtu by increasing the sorbent injection rate and adding halogens to the flue gas, thereby preventing the oxidation of the mercury. This conclusion is based on the mistaken assumption that the mercury removal levels achievable through sorbent injection with subbituminous coals also are achievable by units that burn lignite.

Third, EPA ignores the role of sulfur trioxide (SO_3) in the flue gas for lignite-fired EGUs which impairs the mercury control performance of sorbent injection. The quantities of SO_3 in flue gas reduce the effectiveness of sorbent injection by 50 percent and in some cases create a barrier for achieving mercury levels of 90 percent.

For these reasons, EPA should retain the current mercury standard of 4.0 lb/TBtu and not adopt a more stringent standard, especially the proposed limitation of 1.2 lb/TBtu.

Legal and technical limitations preclude the use of CEMS for demonstrating compliance with the fPM standard.

America's Power opposes EPA's proposal to eliminate quarterly stack tests as the method for demonstrating compliance with the fPM performance standard and instead mandate the use of fPM continuous emission monitors (CEMS). The imposition of CEMS is inappropriate for both legal and technical concerns as outlined below.

The statute does not authorize EPA to make technical changes to the compliance determination procedures when it undertakes the Residual Risk and Technology Review required under section 112 of the CAA. The sole focus of section 112(f)(2) is addressing health risks and has nothing to do with requiring or otherwise authorizing EPA to adopt new compliance methods or procedures, such as the adoption of a fPM CEMS requirement for demonstrating compliance.

Similarly, the technology review provisions in CAA section 112(d)(6) do not authorize EPA to change or impose new methods or procedures for demonstrating compliance. Rather, this statutory provision is limited to authorizing EPA to revise performance standards for limiting emissions but not to establishing new requirements for monitoring or measuring emissions. This statutory limitation on the scope of the technology review is reflected by the fact that section 112(d)(6) only authorizes EPA to "review and revise as necessary … emission standards promulgated under this section no less often than every 8 years."

Furthermore, EPA's technical justification for mandating fPM CEMS is based on inaccurate claims regarding the capabilities and accuracy of CEMS. The many technical problems and limitations with fPM CEMS stem from the fact the CEMS does not provide a direct measure of fPM emissions based on the monitoring instrument measuring the mass of fPM and the volume of the flue gas from which that mass of fPM was sampled. Instead, the fPM CEMS technology measures a property, such as light scatter or beta attenuation, which—in turn—must be correlated to actual stack fPM emissions in order to estimate the fPM emission levels in the flue gas. The technical challenges of this monitoring system generating accurate fPM emissions on a continuous basis under the full range of operating conditions are numerous and difficult to overcome. This would be particularly the case for demonstrating compliance with the stringent fPM limitations, especially if the Agency decides to reduce the fPM standard to 0.010 lb/MMBtu.

Finally, in proposing to mandate fPM CEMS, EPA has failed to show that the benefits of continuous measurement of fPM outweigh the cost of compliance. EPA has not demonstrated that the current system of compliance demonstration is inadequate nor have there been any appreciable changes in fPM monitoring technology over the past few years that would support such a change.

America's Power appreciates the opportunity to submit these comments. Please contact us if you have any questions.

Sincerely,

Michelle Bloodworth
President and CEO

Attachment: "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," June 19, 2023.

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

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1. Summary of Flaws in EPA's Approach

The following is a summary of flaws in EPA's analysis, further described in detail in this report.

Particulate Matter (PM) Database

EPA's database of PM emissions is inadequate. EPA attempts to capture typical PM emissions by acquiring samples from 3 years – 2017, 2019, and 2021. For the vast majority of the units – 80% - EPA uses only 2 of the potentially available 12 quarters (in those 3 years; up to 20 quarters from 2017 to 2021) of data to construct the PM database. Further, of these limited samples. EPA cites the lowest to reflect a target PM emissions rate. EPA cites the use of the "99th percentile" PM rate in lieu of the average compensates for variability; but this approach accounts for variability within a single ("the lowest") quarter. It fails to account for long-term variability, which is affected by changes in fuel and process conditions, among others.

Lack of Design and Compliance Margin

EPA recognizes the need for margin in both design and operation (for compliance) of environmental control equipment, but ignores this concept in developing this proposed rule. The need for design margin is recognized in a 2012 OAQPS memo[1] addressing the initial developments of this very same rule, while margin for operation is considered in evaluating CEMS calibration[2] for this proposed rule. Neither design nor operating margin is considered in setting target PM standards, resulting in underestimation of number of units affected and total costs to deploy control technology. For some owners of fabric filter-equipped units, the revised rate of 0.010 lbs/MBtu eliminates any operating margin.

Inadequate Cost for ESP Rebuild

Of three categories of ESP upgrades considered by EPA, the cost for the most extensive – a complete rebuild to add collecting plate area – is inadequate. Four such major ESP rebuild projects have been implemented for which costs are reported in the public domain – and not acknowledged by EPA. Incorporating these results elevates the range of cost from EPA's estimate of $75-100/kW to $57-213/kW. Consequently, the "average" cost for this action used in the cost per ton ($/ton) evaluation increases from $87/kW to $133/kW.

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[1] Hutson, N., National Emission Standards for Hazardous Air Pollutants (NESHAP) Analysis of Control Technology Needs for Revised Proposed Emission Standards for New Source Coal-fired Electric Utility Steam Generating Units, Memo to Docket No. EPA-HQ-OAR—2009-0234, November 16, 2012. Hereafter Hutson 2012.

[2] Parker, B., PM CEMS Random Error Contribution by Emission Limit, Memo to Docket ID No. EPA-HQ-OAR-2018-0794, March 22, 2023. Hereafter Parker 2023.

Inadequate $/ton Removal Cost

As a consequence of under-predicting capital required for ESP "rebuild," and not recognizing the need for a design and operating margin, EPA under-predicts the number of units requiring retrofit and incurred cost. As a result, in contrast to the annual cost of $169.7 M projected by the Industry Study described in this report, EPA estimates a range from $77.3 to $93.2 M. Further, the Industry Study estimates the cost per ton ($/ton) of fPM to be $67,400, 50% more than the maximum cost estimated by EPA - $44,900 /ton.

Faulty Lignite Hg Rate Revision

EPA's proposal to lower the Hg emission rate for lignite-fired units to 1.2 lbs/TBtu is based on improper interpretation of Hg emissions data – both in terms of the mean rate and variability. EPA's projection that 85 and 90% Hg removal would be required for the proposed rate is incorrect, with up to 95% Hg removal required for some units – a level of Hg reduction not feasible in commercial systems. In addition to the variability of Hg content in lignite, EPA ignores the deleterious role of flue gas SO_3 in lignite-fired units, which compromises sorbent performance and effectiveness – even though this latter barrier is recognized and cited by EPA's contractor for the IPM model.[3]

Faults in IPM Modeling

IPM creates a flawed Baseline scenario that does not adequately measure the impacts of the proposed rule. Most notably, IPM err in the number of coal units that would be retired in both 2028 and 2030; as a consequence, EPA underestimates the number of units subject to the proposed rule. Also, IPM unrealistically retrofitted 27 coal units with carbon capture and storage (CCS) in 2030. Consequently, IPM modeling results of the Baseline likely understate the compliance impacts of the proposed rule.

[3] IPM Model – Updates to Cost and Performance for APC Technologies: Mercury Control Cost Development Methodology, Prepared by Sargent & Lundy, Project 12847-002, March 2013.

2. Introduction

The Environmental Protection Agency (EPA) is proposing to amend the National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Coal- and Oil-fired Electric Utility Steam Generating Units (EGUs), otherwise known as the Mercury and Air Toxics Standards (MATS). The specific emissions limits being revised address the filterable particulate matter (fPM) standard (which is the surrogate standard for non-mercury (Hg) metal HAPs); the Hg standard for lignite-fired units; fPM measurement methods for compliance; and the definition of startup. This report provides a review and evaluation of EPA's approach to selecting the revised fPM standard, the capital and annual costs for achieving the proposed revised standard, and the cost per ton ($/ton) to control non-Hg metal HAPs; and a critique of EPA's basis for proposing an Hg limit of 1.2 lbs/TBtu for lignite-fired units. This document also provides information supporting EPA's decision to retain the present Hg limit for bituminous and subbituminous coal.

The proposal to lower fPM and Hg limits is premised on EPA's interpretation of data related to the cost and capabilities of PM and Hg emission control technologies. EPA reports to have conducted realistic assessments of PM and Hg emissions and control technology capabilities in support of their analysis. EPA's assumptions are reported in the MATS_RTR_Proposal_Technology Review Memo[4] where EPA describes the PM database they developed, the cost and control capabilities of upgrades to electrostatic precipitators (ESPs) and fabric filters, and their understanding of the key factors that affect Hg emissions in bituminous, subbituminous, and lignite coal - and how the latter are alike or differ.

Many of EPA's assumptions are contrary to data in their possession or strategies previously adopted by EPA, but not considered. EGUs have been reporting fPM compliance data to EPA since MATS became applicable to them – i.e., for the vast majority of EGU, April 2015 or April 2016 for units that obtained a one-year extension. However, EPA's effort to "mine" fPM emissions data from prior years provides a sparse, inadequate database that does not reflect operating duty nor account for inevitable variability; further EPA misinterprets this information. No design or operating margins are considered in setting fPM (the same is true for lignite Hg emission rates). The cost to upgrade ESPs to meet the proposed limits is inadequate for the most significant modification EPA envisions – the complete ESP Rebuild. The cost to deploy enhanced operating and maintenance (O&M) actions on existing fabric filers is inadequate. Regarding revised Hg limits for lignite coal, EPA does not recognize the differences in lignite versus Powder River Basin (PRB) subbituminous coal that effect Hg control. EPA draws an incorrect analogy between PRB and lignite, improperly assuming the Hg removal by carbon sorbent observed with PRB can be replicated on lignite.

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[4] Benish, S. et. al., 2023 Technology Review for the Coal- and Oil-Fired EGU Source Category, Memo to Docket ID No. EPA-HQ-OAR-2018-0794. January 2023. Hereafter RTR Tech Memo.

The remaining sections of this report detail the findings summarized in Section 1, and are as follows:

- Section 3 describes EPA's approach to assembling their fPM database, and the flaws and weaknesses in their approach.
- Section 4 evaluates the fPM rates assigned by the database for the EPA analysis.
- Section 5 evaluates EPA's cost bases for the proposed fPM revised standard, and compares these to the realistic assumptions used in the Industry Study described in the paper.
- Section 6 addresses EPA's proposal to lower Hg from lignite-fired units to 1.2 lbs/TBtu, delineating the shortcomings in EPA's approach and assumptions.
- Section 7 provides historical data for Hg emission from non-low rank fuels, showcasing the inherent variability in the 30-day rolling average.
- Section 8 reviews the IPM modeling analysis conducted by EPA to support this rule.
- Appendix B presents examples of PM emission timelines for a limited number of units[5] that show how EPA's sparse database does not capture the authentic "PM signature" of the units.

[5] We reviewed data for a limited number of units because the comment period was very short and did not allow adequate time to undertake a more thorough review. EPA has all the data and in our opinion should have conducted such an analysis for every unit at issue.

3. Description of EPA Reference PM Database

Section 3 describes the PM database assembled by EPA which serves as the basis for the proposed NESHAP rule. Section 3 first describes the coal fleet inventory reflected, and then identifies shortcomings of this database concerning (a) selection of the sample year and quarter, (b) number of samples considered, and (c) data analysis.

3.1 Coal Fleet Inventory

EPA projects that a total of 275 generating units will be operating at the compliance date of January 1, 2028, representing a reduction from the present (2023) operating inventory of approximately 450 units. EPA identified the 275 units based on their estimate of unit retirements and units planning to switch to natural gas by the compliance date. EPA accounted for these assets not as individual units, but in terms of the number of reporting monitors to the Clean Air Markets Division. As 27 units employ common stack reporting, the data presented by EPA in the draft rule and RTR Tech Memo consider 248 discrete data points that reflect the 275 units. This analysis will adopt the same reporting methodology.

EPA's selection of 275 units contains 22 units that have publicly disclosed plans to retire or switch to natural gas by the compliance date of January 1, 2028. For the purposes of this analysis, these units are retained in the database so the results can be more readily compared.

Figure 3-1 depicts the installed inventory projected by EPA, presented according to the suite of control technology. The first two bars (from the left) report units equipped with ESPs as the primary PM control device in the following configurations: a total of 54,116 MW for an ESP followed by a wet FGD; and a total of 16,346 MW with an ESP only. The next 3 bars describe the total inventory equipped with a fabric filter in the following three configurations: 12,194 MW with the fabric filer as the sole device; 20,206 MW with a fabric filter followed by a wet FGD, and 19,995 MW where the fabric filter is preceded by a dry FGD process. Consequently, the bulk of the inventory (70,462 MW) will employ an ESP as part of the control scheme, with 52,395 MW employing a fabric filter for PM. Given the role of wet FGD in PM emissions – in most cases such devices will reduce PM by approximately 50% - more than half (74,322 MW) employ wet FGD as the last control step.

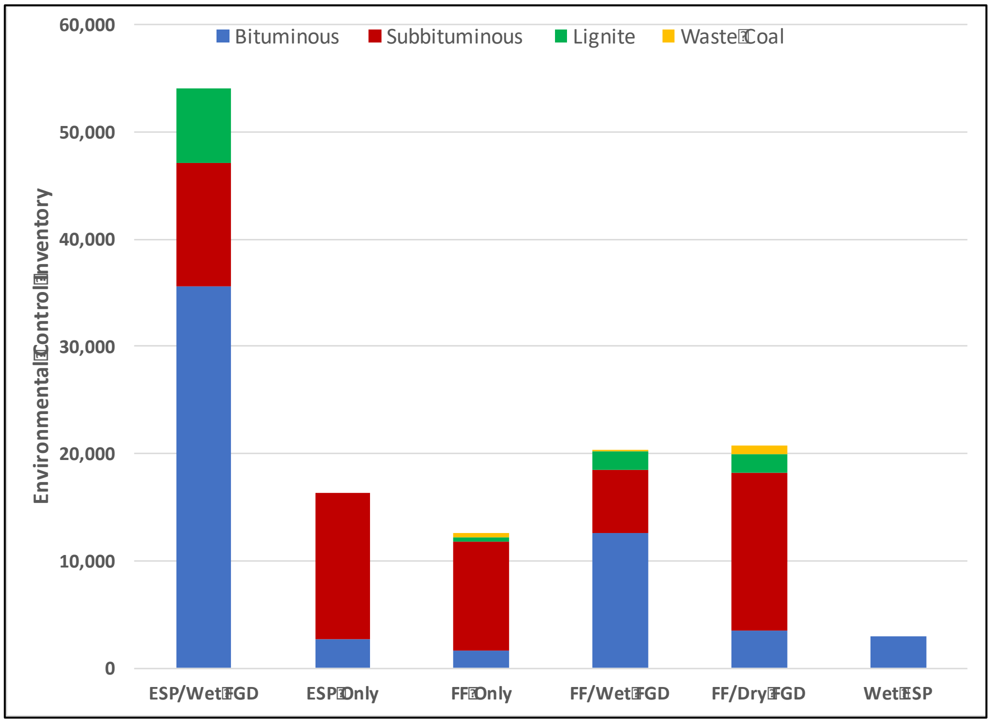

Figure 3-1. Inventory of EPA-Project 2028 Fleet by Control Technology Suite

3.2 Database Characteristics

Several characteristics of EPA's database severely compromise the quality of the analysis. These are the (a) selection of sampling year and quarter and (b) number of samples used.

3.2.1 Selection of Sample Year and Quarter

EPA does not describe the rationale for the limited data selected. The selection of three reference years (2017, 2019, and 2021) from at least 5-6 years of data readily available to EPA, and the sampling periods within each year (typically the 1st or the 3rd quarter even though all quarters are generally available) are not discussed. EPA extracts data from the year 2021 using a different approach from the years 2019 and 2017 without explanation. EPA states for 2021 that 2 quarters of data are utilized (always the 1st and the 3rd). For 2019, EPA reports utilizing data from "quarters three and occasionally four" while for 2017 EPA reports data acquired from "variable quarters."[6]

The rationale for the irregular selection of quarters is not stated. For 2021, the first and third quarters are selected with no technical basis. For 2019, the selection of quarters three and "occasionally" four does not replicate the time periods selected for 2021. For 2017, there is no description of the quarters or selection criteria.

EPA ignores a rich field of data that could support a much more robust and reasonable analysis.

[6] RTR Tech Memo, page 2.

3.2.2 Number of Samples

The number of discrete data points in EPA's Reference Database – defined by the number of operating quarters – is extremely limited. EPA's description of the sampling approach[7] is as follows:

Quarterly data from 2017 (variable quarters) and 2019 (quarters three and occasionally four) were first reviewed because data for all affected EGUs subject to numeric emission limits had been previously extracted from CEDRI. In addition, the EPA obtained first and third quarter data for calendar year 2021 for a subset of EGUs with larger fPM rates (generally greater than 1.0E-02 lb/MMBtu for either 2017 or 2019).

Figure 3-2 shows most monitor locations — 193 of the 245 — are characterized by only 2 quarters of data, which is inadequate compared to the 16 or 20 EPA has access to. The distribution of quarters selected by EPA according to either CEMS or stack test measurement for all 245 locations is shown. The second largest category is 33 units characterized by 4 quarters.

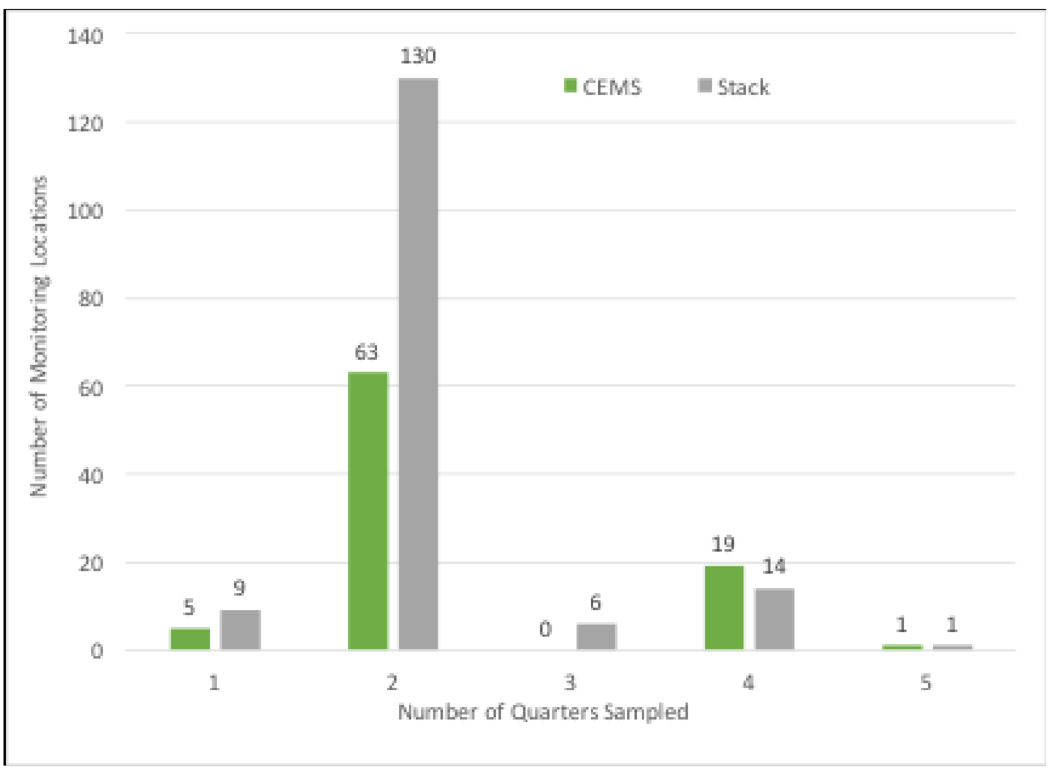

Figure 3-2. Numbers of Quarters Sampled by EPA for Use in PM Database

[7] RTR Tech Memo, page 2.

Additional depictions of the data (not shown) reveal that only nine units are described by data in 2017, and 187 units by data from 2019. Only 41 units are described by data in 2021; the lack of data in 2021 was intentional as EPA considered this year only if data from 2017 or 2019 showed the unit exceeding the 0.010 lbs/MBtu proposed limit.[8] In other words, EPA looked at 2021 only when it was trying to find an emission rate less than 0.010 lbs/MBtu for a unit.

3.2.3 PM Data Selection and Analysis

EPA does not explain the methodology chosen to reflect each quarters' emission rate, using at least two methods, depending on the year. EPA followed a four-step process to construct its database to select the "base rate" for each unit. The process is described as follows:

<u>Step 1: Quarter Selection</u>. EPA looked at 2-4 (usually 2) quarters for each unit. EPA states: "Quarterly data from 2017 (variable quarters) and 2019 (quarters three and occasionally four) were first reviewed …. In addition, the EPA obtained first and third quarter data for calendar year 2021 for a subset of EGUs with larger fPM rates (generally greater than 1.0E-02 lb/MMBtu for either 2017 or 2019)."[9]

As noted previously, EPA considered Q1 and Q3 2021 data solely to find a PM rate lower than 0.010 lb/MMBtu, and further explained: "The quarterly 2021 data summarizes recent emissions and also reflect the time of year where electricity demand is typically higher and when EGUs tend to operate more and with higher loads."[10]

<u>Step 2. Select Single Quarter</u>. From the candidate quarters identified in Step 1, EPA selected a single value, using criteria specific for each tests methodology:

- *PM CEMS*: for quarters in 2017 and 2019, EPA selected the 30-day average observed on the last day of the quarter; for quarters in 2021, EPA determined the average of the 30-day rolling averages observed in that quarter.
- *Stack Tests*: EPA took the average of the multiple (usually 3) test runs.

<u>Step 3. Select Lowest Quarter</u>. EPA selected the "lowest quarter" PM rate from the quarters selected in Step 2.

<u>Step 4. Determine PM of 99th Percentile.</u> For this lowest quarter per Step 3, EPA calculated the statistical percentile values as observed over the entire quarter. The methodology varied on whether PM CEMS or stack test data was provided. For PM CEMS, the percentiles were calculated for all 30-day rolling averages in the quarter. For stack tests, the percentiles were calculated for the typically 3 test runs.

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[8] Personal communication: Sarah Benish to Liz Williams, April 28, 2023. "*Data for 2021 was mined only for the EGUs that showed 2017 or 2019 fPM data above 1.0E-02 lb/MMBtu. We did not mine 2021 PM data for EGUs not expected to be impacted by the proposed fPM limit.*"

[9] RTR Memo, page 2.

[10] Ibid.

The results are reported in Appendix B of the Technology Review Memo. The 99th percentile rate was chosen as the "base rate," supposedly to account for variability within the "lowest quarter."

EPA does not describe why data selected was restricted to the years 2017, 2019, and 2021. EPA does not explain why 2021 data was limited to the 1st and 3rd quarters, 2019 data was limited to the 3rd and occasionally the 4th quarter, while 2017 data from variable quarters could be utilized.

Of concern is the limited subset of data used for this analysis – Figure 3-2 showed that for 80% of the units the lowest is selected from only two samples. EPA states "By using the lowest quarter's 99th percentile as the baseline, the analyses account for actions individual EGUs have already taken to improve and maintain PM emissions."[11] EPA states employing the PM rate at the 99th percentile –reflecting approximately the highest data within that quarter – remedies any bias.[12]

There is no basis for this statement. EPA is assuming that because a unit emitted fPM during a single quarter at a particular level, the lowest such level must necessarily reflect "actions individual EGUs have already taken to improve and maintain PM emissions," and therefore each EGU must be able to replicate that rate in every quarter going forward, indefinitely. Also, EPA ignores the unavoidable variability in emission rates: the "actions individual EGUs have already taken to improve and maintain PM emissions" are not the only factor that determines fPM emissions rate. The factors that affect fPM rates are numerous and include but are not limited to the following: coal quality (e.g., chemical composition and ash content) which varies within a single mine; variation in temperature within an ESP; content of SO_3 and trace constituents that determine ash electrical resistivity; physical conditions (spacing) of collecting plates and emitting electrodes; effectiveness of the rapping "hammers" that dislodge collected ash from the collecting plates; and physical properties of the collected ash layer that define ash re-entrainment. Further, boiler operation will influence ESP performance, most notably unit duty (i.e., relatively stable operating level for a "baseload" unit versus more load changes for an intermediate unit or a unit operating in peaking mode), operating level, and load "ramp" rate. Achieving the "least emission" rate observed during a quarter that EPA selected is not necessarily feasible at other times and under other conditions.

3.2.4 Example Cases

Figure 3-3 presents an example that demonstrate the shortcomings of EPA's approach. Figure 3-3 presents PM data from Coronado Generating Station Units 1 and 2 reflecting all operating quarters from 2017 through 2021. Both the average PM rate and the 99th percentile from each quarter are presented for 20 quarters of operation over the 4-year period. Figure 3-3 also identifies the two samples EPA selected from 2017 Q3 and 2019 Q3 as representative of low fPM rate, with the latter as the "least" – and the 99th-percentile reporting 0.0086 lbs/MBtu. Figure 3-3 shows EPA's two samples do not capture the full character of Coronado operating duty (with the red dotted line denoting the PM rate selected as representative of the units'

[11] RTR Tech Memo, page 4.

[12] Ibid.

capabilities to control PM). These quarters as selected by EPA are far from representative of unit operations or capabilities: among 20 quarters for which data are available, the units' 90th percentile fPM rates exceed the 0.0086 lbs/MBtu rate EPA selected for 16 quarters. Ten out of 20 quarters showed 90th percentile fPM rates exceeded the proposed standard of 0.010 lb/MBtu.

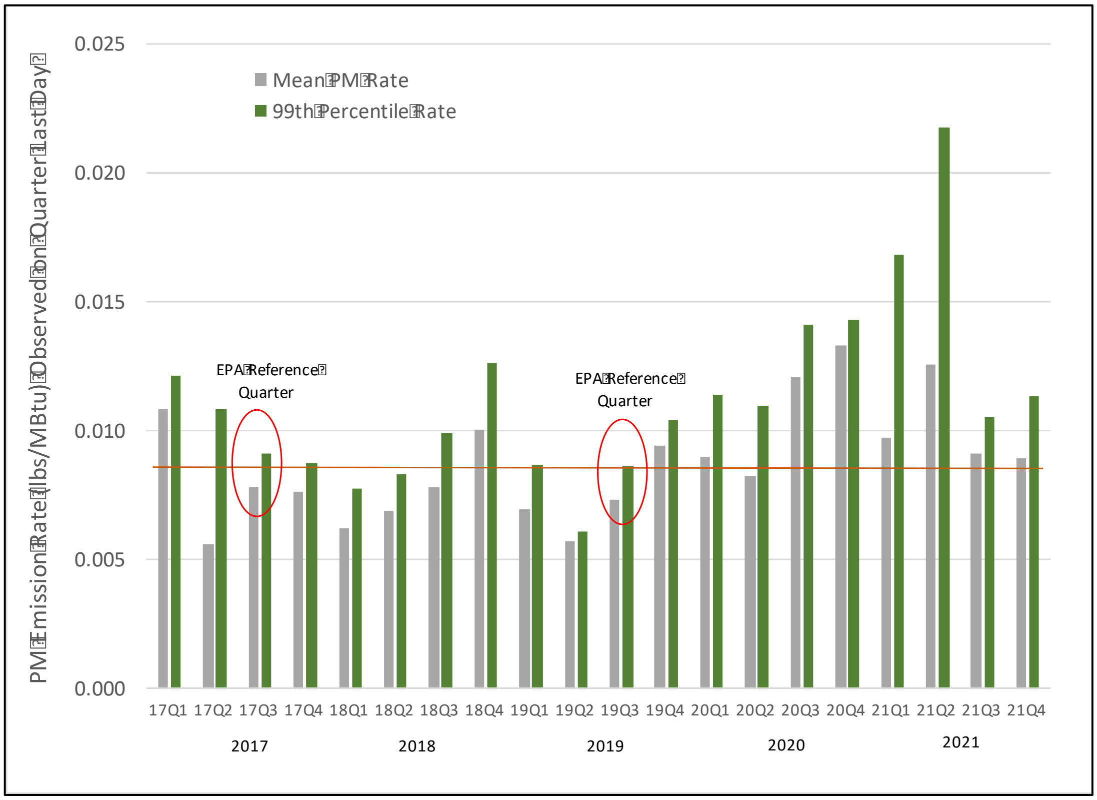

Figure 3-3. Coronado Generating Station: 20 Operating Quarters

Coronado Units 1/2 show how selecting the least PM rate of any quarter, and adopting the 99th percentile PM rate within that quarter, does not capture the variability in fPM emission rates, which are affected by the variability of coal and operating conditions, among others. These examples demonstrate that EPA used best-case fPM data from both compliance measures (continuous monitor and performance test data).

Additional examples are presented in the Appendix B to this report.

3.3 Conclusions

- EPA's database is sparse and does not fully capture operating duty. Of the 275 units and approximately 250 monitoring locations, the vast majority – 80% - are characterized by only two samples.

- Selecting the lowest quarter - "one" of what in most cases are "two" samples - fails to capture the operating profile of the unit, and presents a serious deficiency in representing operations. EPA's approach of considering the 99th percentile within a quarter is inadequate to assess variability, particularly that induced by fuel composition, as such fuel changes are observed over a characteristic time of years and not several months.

- The use of statistical means within one quarter does not capture the multi-month variances in coal composition, seasonal load, and process conditions that are not constrained to 3-month events.

- An improved, robust database would allow observing variation between– as opposed to within – operating quarters, to better reflect variations and uncertainties in operating duty and fuel supply.

4. Coal Fleet PM Emissions Characteristics

Section 4 characterizes the coal-fired fleet selected to represent the PM emissions

The emission control technologies on the 275 units projected by EPA to be operating in 2028 present a variety of approaches to lower fPM emission limits – with implications for upgrades and actions that would be required to meet a revised standard for fPM. This subsection presents the distribution of control technology by ability to operate below the revised PM limits for the units in EPA's database. By necessity, this analysis uses EPA's database (both for a discussion of expected or achievable fPM emission rates and the units projected to operate in 2028 and later), and such use does not represent an endorsement or acceptance of EPA's approach. As discussed above, EPA's analysis of expected/achievable fPM emission rates is inadequate. And as discussed later in this report, EPA's selection of units that would continue to operate after 2028 is flawed: it contains multiple errors; and EPA's post-IRA IPM analysis is inaccurate.

Figure 4-1 is used to present our analysis.

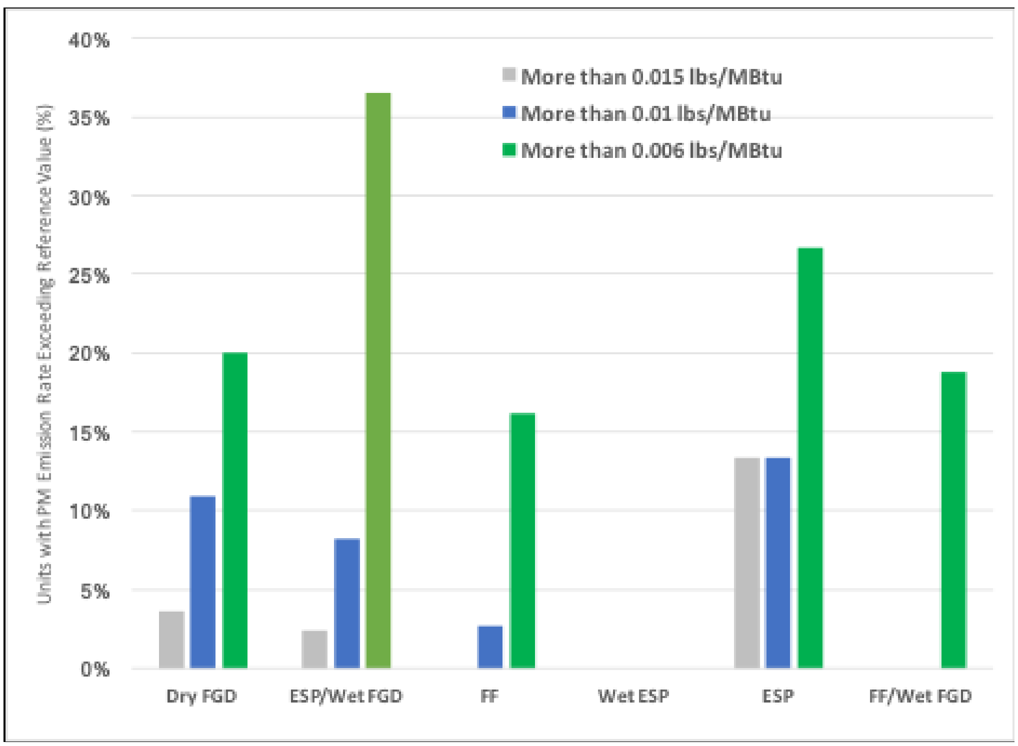

Figure 4-1. Fraction of Units Exceeding Three PM Rates: By Control Technology

Figure 4-1 presents for five control technology configurations the percentage of units that emit (according to EPA's chosen "base rate") above the following PM emission limits: 0.015 lbs/MBtu, 0.010 lbs/MBtu, and 0.006 lbs/MBtu. The control technologies are (a) dry FGD with a fabric filter, (b) ESP followed by a wet FGD, (c) fabric filter alone (employing low sulfur coal or multi-unit station-averaging to meet an SO_2 limit), (d) wet ESP as the last control device, (e) ESP alone (employing low sulfur coal or multi-unit station-averaging to meet an SO_2 limit), and (f) fabric filter followed by a wet FGD.

In Figure 4-1, the proportion of units in the inventory that exceed the contemplated fPM rate is proportional to the height of the bar; a higher bar implies a greater fraction of units in the inventory exceed the contemplated fPM rate. Thus:

4.1.1 PM Rate of 0.015 lbs/MBtu

Units in three categories exceed this highest contemplated rate – those with an ESP alone, a dry FGD followed by a fabric filter, and an ESP followed by a wet FGD. The latter category of ESP/wet FGD benefits in that actions within the absorber tower – although not designed to removed fPM – can under some conditions remove fPM. Data describing PM removal via wet FGD is sparse but suggests 50% removal can be observed.

4.1.2 PM Rate of 0.010 lbs/MBtu

The number of units in each of the three preceding categories exceeding this rate increases – there is no change for the category of ESP-alone, but the number of units exceeding this rate more than triple for dry FGD/fabric filter and ESP/wet FGD. No units with fabric filter/wet FGD or a wet ESP emit at greater than this rate.

4.1.3 PM Rate of 0.006 lbs/MBtu

The number of units exceeding a rate of 0.006 lbs/MBtu increases with this most stringent contemplated rate. More than 1/3 of the units with ESP/wet FGD and ¼ of ESP- only cannot meet this rate, with fabric filters either operating with dry FGD (20%) or alone (16%) not achieving this target. Almost 20% of those with fabric filter/wet FGD units emit greater than this value.

In conclusion, within six major categories of control technology, units equipped with fabric filters achieve the lowest PM rates. Units with ESPs – either operating alone or with a wet FGD- represent the highest fraction of their population that exceed the strictest contemplated rate. Units with fabric filters – operating alone, or as part of a wet or dry FGD arrangement – are among the lowest exceeding the strictest contemplated PM rate. As noted previously, this analysis used EPA’s database (as reflected in Appendix B of the RTR Tech Memo) out of necessity, and such use does not represent an endorsement or acceptance of EPA’s approach.

5. CRITIQUE OF COST-EFFECTIVENESS CALCULATIONS

Section 5 addresses the cost effectiveness ($/ton basis) estimated to reduce the PM emission rate to EPA's proposed limit of 0.010 lbs/MBtu, and the alternative limit of 0.006 lbs/MBtu. EPA has conducted this calculation with inputs based on analysis by Sargent & Lundy (S&L)[13] and Andover Technology Partners (ATP).[14] EPA's results are presented in both Table 3 of the proposed rule and in Table 7 of the RTR Tech Memo.

This section reviews EPA's calculation methodology, critiques inputs of the EPA Study, and presents results of an Industry Study that utilizes realistic costs. Results from EPA's evaluation and the Industry Study addressing the 0.010 lbs/MBtu and 0.006 lbs/MBtu PM rates are compared.

5.1 EPA Evaluation

5.1.1 EPA Study Inputs

The EPA study used both the PM database described in Section 3 and cost and technology assumptions derived by the above-mentioned S&L and ATP references. As noted in Section 2, EPA's sparsely-populated database is inadequate from which to base a revised PM rate that represents a significant reduction in PM emissions but is achievable in long-term duty.

The analyses by S&L and ATP provide capital cost for three categories of ESP upgrades, improvements to fabric filter operating and maintenance (O&M) and associated costs, capital requirement for fabric filter retrofit and associated O&M cost. Most of the analysis is premised on the costs and PM removal performance of ESP upgrades as defined by S&L. It should be noted S&L did not provide specific projects with publicly available data as the basis of their assumptions.

The most significant shortcoming of EPA's assumptions is low capital estimates for the most significant ESP upgrade - the "ESP Rebuild" scenario. In contrast to the generalizations of the S&L memo, Table 5-2 reports publicly documented costs incurred for "ESP Rebuild." Equally significant, EPA ignores the inherent variability of fPM and FGD process equipment by not utilizing a design or operating margin in selecting the value of fPM rates that would require operator action. This is counter to EPA's prior acknowledgement of the use of margin in the initial rulemaking for MATS[15] and recent observations as to CEMS calibration.[16] It is also contrary to basic operation goals: no source operates at the applicable standard; a compliance

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[13] PM Incremental Improvement Memo, Project 13527-002, Prepared by Sargent & Lundy, March 2023. Hereafter S&L PM Improvement Memo.

[14] Analysis of PM Emission Control Costs and Capabilities, Memo from Jim Staudt (Andover Technology Partners) to Erich Eschmann, March 22, 2023. Hereafter ATP 2023.

[15] Hutson 2012.

[16] Parker 2023.

margin is always necessary, at least to account for unavoidable variability of performance in the real world. By ignoring the need for margin, EPA's evaluation under-predicts the number of units that would be retrofit with new or upgraded control technology to meet the target rate.

These and other critiques of EPA's approach are discussed subsequently.

Shortcomings in EPA inputs compromise the results of their analysis. These shortcomings, as well as other observations, are summarized as follows:

<u>ESP Upgrade</u>. Three categories of ESP upgrade are proposed by EPA. The most significant shortcoming relates to the "ESP Rebuild" category in which - as described by S&L – additional plate area is added to the ESP. The addition of collecting surface area will require major changes to – or demolition and complete rebuilding of – the gas flow confinement that houses the existing collecting plates. Also, these process changes require specialized labor for fabrication and installation that may be limited in availability. The costs suggested by S&L (without citation of references) - $75-100/kW –are low when compared to publicly disclosed costs from similar projects.

<u>Fabric Filter O&M</u>. Fabric-filter-equipped units that emit greater than 0.010 lbs/MBtu are assumed to adopt enhanced O&M practices. These enhanced practices consist of (a) upgrading filter material to higher quality fabrics, such PTFE, and (b) increasing the replacement frequency so that filters are replaced on a 3-year basis. The cost premium for this action, based on analysis by ATP, does not consider the additional manpower costs for the more frequent replacement.

<u>Fabric Filter Construction</u>. EPA's range of capital cost for retrofit of fabric filter technology is consistent with industry experience.

<u>Design/Compliance Margin</u>. A premise of environmental control system design is accounting for variability due to many factors, including, for example, variations in fuel composition, operating load, and process conditions. Such variability is generally addressed by a design/compliance margin – selecting a target emission rate less than mandated by a standard. The concept of design/compliance margin is broadly applied in the industry, and was acknowledged in a 2012 EPA memo summarizing the range of margin adopted by various process suppliers, with a minimum cited as 20-30%.[17] EPA did not adopt a design/compliance or operating margin in selecting fPM emission rates for a revised fPM standard in this evaluation, despite the fact that elsewhere in the record of this proposal EPA acknowledges a typical "operational target" of 50% of the limit.[18] Because of its assumption of no design/compliance margin whatsoever, EPA presumes that units that report an operating fPM of 0.010 lbs/MBtu – based on EPA's sparse database - require no investment to meet the proposed standard of 0.010 lb/MBtu.

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[17] Hutson, N., National Emission Standards for Hazardous Air Pollutants (NESHAP) Analysis of Control Technology Needs for Revised Proposed Emission Standards for New Source Coal-fired Electric Utility Steam Generating Units, Memo to Docket No. EPA-HQ-OAR—2009-0234, November 16, 2012.

[18] Parker 2023.

Separate from the preceding issues, EPA did not disclose the capacity factors assumed in the analysis. The capacity factor can be inferred from the tons of PM removed as reported in Appendix B of the RTR Tech Memo; this requires acquiring heat input and net plant heat rate from AMPD and EIA data.

5.1.2 EPA Results

Table 5-1 presents results of EPA's evaluation.

Table 5-1. Summary of EPA Results

EPA Study					
Unit Affected	Tons fPM Removed	Annual Cost ($M/y)	$/ton fPM (average)	Non-Hg metallic HAPS Removed (tons)	$/ton non-Hg metallic HAP ($000s)
Target: 0.010 lbs/MBtu					
20	2,074	77.3-93.2	37,300-44,900	6.34	12,200-14,700
Target: 0.006 lbs/MBtu					
65	6,163	633	103	24.7	25,600

<u>Proposed Limit: 0.010 lbs/MBtu</u>. EPA estimates 20 units in the entire inventory are required to retrofit some form of ESP upgrade. The number of units with existing fabric filters required to enhance O&M is not identified, nor is their cost. EPA estimates a range in annual cost to implement the ESP and fabric filter O&M enhancement of $77.3 to 93.2 M/yr, with the range determined by the range in cost and performance of each option as described by S&L.[19] This total annualized cost translates into an average fPM removal cost effectiveness of $37,300 - $44,900 per ton of fPM and $12.2M -$14.7 M per ton of total non-Hg metallic HAPs. These steps remove a total of 2,074 tons of fPM (6.34 tons of total non-Hg metallic HAPs) annually.

EPA did not consider in its analysis the potential impact of the capital cost of major controls construction or upgrades (i.e., ESP rebuilds for most of the 20 units; new Fabric Filters for the two Colstrip units) on the viability of the units at which such rebuilds would occur. Appendix Figure A-1 presents the capital required for each unit as designated by EPA for upgrade – requiring an investment likely prohibitive for continued operation.

<u>Potential Limit: 0.006 lbs/MBtu</u>. EPA estimates 65 units in the entire inventory are required to retrofit a fabric filter or deploy enhanced O&M to an existing fabric filter. EPA estimate an annual cost of $633 M/yr will be incurred, at an average cost effectiveness of $103,000 per ton

[19] S&L PM Improvement Memo.

of fPM and $25.6 M per ton of total non-Hg metallic HAPs. These steps remove a total of 6,163 tons of fPM (24.7 tons of total non-Hg metallic HAPs) annually.

5.2 Industry Study

The Industry Study alters several assumptions to reflect actual, documented cost data and the necessity of a design/compliance margin. Table 5-2 presents these results.

5.2.1 Revised Cost Inputs

The modified cost inputs necessary to reflect authentic conditions ESP upgrade and fabric filter operation are discussed as follows.

<u>ESP Upgrades.</u> The three categories of ESP upgrades are assessed as follows.

Minor Upgrades (Low Cost). Both the cost range and PM removal efficiency for this activity as estimated by S&L are adopted for this analysis. ESPs requiring Minor Upgrade are assigned a $17/kW cost to derive an average of 7.5% removal of fPM.

Typical Upgrades (Average Cost). Both the cost range and PM removal efficiency for this activity as estimated by S&L are adopted for this analysis. ESPs requiring Typical Upgrade are assigned a $55/kW cost to derive an average of 15% fPM removal.

ESP Rebuild (High Cost). The cost range for this activity as estimated by S&L does not reflect that reported publicly for four projects that represent the "ESP Rebuild" category. Two projects were completed at the AES Petersburg station – the complete renovation of the ESPs on Units 1 and 4[20] for which S&L provided engineering services. The cost for this work has been publicly reported in 2016-dollar basis. Two additional major ESP upgrades were implemented by Ameren at the Labadie station unit in 2014 – with costs publicly reported.[21]

Table 5-2 summarizes the cost incurred for the four major ESP retrofits, including costs in the year incurred and escalated (using the Chemical Engineering Process Cost Index)[22] to 2021. Table 5-1 shows a cost range of $57-209/kW, with 3 of the 4 units incurring a cost exceeding $100/kW. These costs significantly exceed EPA's maximum for this range.

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[20] State of Indiana – Indian Public Utility Commission, Cause No. 44242, August 14, 2013. See Appendix, electronic page 50 of 51.

[21] Ameren Missouri Installs Clean Air Equipment at its Labadie Energy Center; https://ameren.mediaroom.com/news-releases?item=1351

[22] https://www.chemengonline.com/pci-home#:~:text=Since%20its%20introduction%20in%201963,from%20one%20period%20to%20another.

Table 5-2. ESP Rebuild Costs: Four Documented Cases

Owner/Station	Unit	Basis Year	2021 ($/kW)
AES/Petersburg	1	2016	117
AES/Petersburg	4	2016	57
Ameren Labadie	1	2014	192
Ameren Labadie	2	2014	209

Consequently, the range of ESP rebuild costs is adjusted to $57-209/kW, and the mean value of $133/kW (2021 basis) selected to represent this category of upgrade.[23]

FF O&M. A fabric filter O&M cost was derived for existing units, based on the assumption by S&L that filter material will be upgraded, as well as the frequency of filter replacement. An increase in cost – reflected as fixed O&M – of $515,000 is estimated for a 500 MW unit. This cost premium is comprised of higher material cost of $425,000 to upgrade filter material to PTFE fabric and an additional $90,000 for installation labor. This cost premium as is assigned to existing units based on generating capacity, and using a conventional "6/10th" power law.

The revised Industry Study costs are based on (a) gas flow volume treated, (b) surface area of filter required based on the unit design, (c) unit cost of filter (e.g. $ per ft^2 of cleaning surface), and (d) replacement rate of filter material. Gas flow treated for each unit was determined using the quantitative relationships derived by S&L for fabric filter cost evaluation developed for the IPM model.[24] Filter surface area was not defined for each unit as dependent on the specific air/cloth ratio; rather a fleet air/cloth ratio of 5 – a mean value between conventional and pulse-jet design concepts – is selected. The unit cost for fabric was selected (at $4.00/ft^2) per ATP analysis. Per S&L's IPM fabric filter costing procedure[25] and the EPA-sponsored review of filter material cost,[26] the increase in cost for enhanced O&M is derived. The cost to upgrade material, accelerate filter replacement (from 5 to 3 years) and supporting cages (from 9 to 6 year) intervals is estimated as $425K per year for a reference 500 MW unit.

Fabric Filter Capital Cost. EPA proposed a capital cost to retrofit a fabric filter as $150-$360/kW. The cost range offered by EPA is consistent with industry experience and is used in this study.

EPA did not share the incremental operating cost incurred by the retrofit fabric filters. The Industry Study adopted fixed and variable operating costs from the previously cited S&L fabric filter cost estimating procedure. For the assigned inputs, the S&L evaluation projects a fixed

[23] Colstrip Units 3 and 4 are equipped with legacy FGD that combine removal of SO2 and PM in a wet venturi; there is not an ESP option to upgrade. Fabric filer retrofit is the only option; as Colstrip represents an atypical case the costs are reported in the category of Major ESP upgrade.

[24] IPM Model – Updates to Cost and Performance for APC Technologies: Particulate Control Cost Development Methodology, Project 13527-001, Sargent & Lundy, April 2017. Hereafter S&L Fabric Filter 2017.

[25] Ibid.

[26] ATP report.

O&M of $0.27/kW-yr and a variable operating cost of 0.48 $/MWh. The variable O&M cost is mostly comprised of filter replacement at the accelerated rate described, and auxiliary power.

<u>Design/Compliance Margin</u>. EPA in two public documents address – and apparently recognize – the need for design/compliance margin.[27] The use of design/compliance margin was acknowledged in a 2012 EPA memo summarizing the range adopted by various suppliers, citing a minimum of 20-30%.[28] For the proposed limit of 0.010 lbs/MBtu, the minimum of 20% is used as a design target for ESP upgrades. Thus, the Industry Study applied ESP upgrade and fabric filter O&M enhancements to attain 0.008 lbs/MBtu, in lieu of EPA's target of 0.010 lbs/MBtu. It should be noted this 20% margin is the least of those considered; if the highest operating margin of 50% suggested by EPA in the record of this rule was used the units requiring upgrade and the cost would have been even higher.

As noted by EPA, the sole reliable compliance means for a 0.006 lbs/MBtu PM rate is a fabric filter. Fabric filters historically exhibit low variability due to their inherent design; thus, the operating margin is slightly relaxed to 0.005 lbs/MBtu. Consequently, the Industry Study assumed ESP-equipped units emitting greater than 0.005 lbs/MBtu will retrofit a fabric filter to insure 0.006 lbs/MBtu is attained. Units with existing fabric filters operating at greater than 0.005 lbs/MBtu will adopt improved operation and maintenance, as previously described.

5.2.2 Cost Effectiveness Results

Revised costs from the Industry Study are projected for the proposed fPM limit of 0.010 lbs/MBtu, and the alternative rate of 0.006 lbs/MBtu. Table 5-4 presents these results.

<u>Proposed Limit: 0.010 lbs/MBtu</u>. Results derived in the Industry Study are reported for all three categories of ESP upgrade in Table 5-1. A total of 26 units are required to upgrade ESPs – 11 deploying *Minor*, 7 deploying *Typical*, and 8 deploying *Major* upgrades.[29] In addition, 11 units equipped with fabric filters are required to enhance O&M activities. The totality of these actions each year incur an operating cost of $169.7 M/yr, and remove 2,523 tons of PM.

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[27] Hutson, 2012 and Parker, 2023.

[28] Hutson, N., National Emission Standards for Hazardous Air Pollutants (NESHAP) Analysis of Control Technology Needs for Revised Proposed Emission Standards for New Source Coal-fired Electric Utility Steam Generating Units, Memo to Docket No. EPA-HQ-OAR—2009-0234, November 16, 2012. at 1 (discussing mercury); 2 (discussing PM).

[29] The two Colstrip units are equipped with an early generation FGD process which does not include an ESP, thus the concept of an ESP upgrade is irrelevant. Consistent with EPA's assumption, the Colstrip units are assumed to retrofit a fabric filter as the only option to meet a limit of 0.010 lbs/MBtu.

Table 5-3. Summary of Results: Industry Study

Technology (Units Affected)	**Annual Cost ($M/y)**	**Tons fPM Removed**	**$/ton fPM average**	**Non-Hg metallic HAPS Removed (tons)**	**$/ton non-Hg metallic HAP ($000s)**
Target: 0.010 lbs/MBtu					
ESP Minor (11)	20.9	100	209,340	0.31	67,470
ESP Typical (7)	34.7	282	122,926	0.86	40,216
ESP Major † (8)	113.6	1,665	68,228	5.1	21,662
FF O&M (11)	0.4	475	869	1.45	284
Total or Average	169.7	2,523	67.3	7.71	22,000
Target: 0.006 lbs/MBtu					
FF O&M (23)	1.23	652	1,887	2.61	617
FF Retrofit (52)	1,955.4	6,269	311,900	25.13	102,000
Total or Average	1,956.6	6,921	282,715	27.74	92,470

† Includes 2 fabric filters retrofit to Colstrip Units 3 and 4. See footnote #23.

The incurred cost per ton varies significantly by ESP upgrade category. For the ESP *Minor* upgrade, the average cost effectiveness is approximately $67,470,000 per ton of non-Hg metal HAP for 0.31 of tons removed ($209,340 per ton of fPM for 100 tons of fPM removed). The cost-effectiveness cost effectiveness for the ESP *Typical* upgrade average $40,216,000 per ton of non-Hg metal HAP for 0.86 tons removed ($122,956 tons of fPM for 282 tons of fPM removed). The *Major* upgrade removes the most non-Hg metal HAP – 5.1 tons – (1,665 tons of fPM) for an average cost effectiveness of $21,662,000 per ton of non-Hg metal HAP ($68,228 per ton of fPM). The most cost-effective control evaluated is enhanced fabric filter O&M, which removes 1.45 tons of non-Hg metal HAP at a cost-effectiveness of $284,230/ton (475 tons of fPM at a cost-effectiveness of $869/ton).

These actions cumulatively remove a total of 2,523 tons of PM for an average cost <u>effectiveness</u> of 22,000,000 per ton of non-Hg metal HAP ($67,262 per ton of fPM) removed, a 50% increase compared to the cost estimated by EPA.

Appendix Table A-1 reports the units to which the Industry Study assigned ESP upgrades, and defines the category of upgrade to meet the proposed fPM limit of 0.010 lbs/MBtu.

Possible Lower Limit: 0.006 lbs/MBtu. The Industry Study projects 52 ESP-equipped units would be required to retrofit a fabric filter, removing 25.13 tons of non-Hg metal HAP (6,269 tons of fPM) for an average cost effectiveness of $102,000,000 per ton of non-Hg metal HAP ($311,900 per ton of fPM). In addition, 23 existing units equipped with fabric filters would have to adopt enhanced O&M, removing an additional 2.61 tons of non-Hg metal HAP (652 tons of fPM) for an average of cost of $617,195/ton of non-Hg metal HAP ($1,887/ton of fPM). These actions cumulatively remove a total of 27.74 tons of non-Hg metal HAP (6,921 tons of fPM) for an average cost effectiveness of $92,470,000/ton non-Hg metal HAP ($282,715/ton of fPM) removed. These costs are a factor of almost three times that projected by EPA.

Appendix Table A-2 reports the units to which the Industry Study assigned fabric filter retrofits and enhancements of operating and maintenance procedures, to meet the alternative fPM limit of 0.006 lbs/MBtu.

5.3 Conclusions

- EPA's cost study is deficient in terms of the number of ESP-equipped units required to retrofit improvements, the capital cost assigned for the most significant *Major* ESP improvement, and estimates of $/ton cost-effectiveness incurred. EPA, by ignoring the need for a design and operating margin cited in at least two of their publications (Hutson, 2012 and Parker, 2023) under-predicts the number of units that would require retrofits.

- This study – using the minimum margin cited by EPA in previous publications – projects a much higher annual cost for capital equipment to meet the proposed 0.010 lbs/MBtu - $169.7 M versus EPA's maximum estimate of $93.3 M. To meet the alternative PM rate of 0.006 lbs/MBtu, this study projects 50% more units (87 versus 65) must be retrofit with fabric filters or implement enhanced O&M to an existing fabric filter, incurring an annual cost of $1.96 B versus EPA's estimate of 633 M/yr – a three-fold increase.

- As a consequence, this study predicts the cost effectiveness to meet 0.010 lbs/MBtu will average $22,000,000 per ton of non-Hg metal HAP removed ($67,262 per ton of fPM), a 50% premium to EPA's estimate of $12,200,000 - $14,700,000/ton of non-Hg metal HAP ($37,300 – $44,900/ton of fPM) removed. This study projects the cost to meet the alternative rate of 0.006 lbs/MBtu will average $92,470,000/ton non-Hg metal HAP ($282,715/ton fPM) removed, almost a factor of three higher than EPA's estimate of $103,000/ton.

6. Mercury Emissions: Lignite Coals

Section 6 addresses EPA's proposed action to reduce the limit for Hg for lignite-fired units to 1.2 lbs/TBtu. (the following Section 7 addresses EPA's proposal to retain the present emission limit of 1.2 lbs/TBtu for units firing bituminous and subbituminous coals (i.e., non-low rank fuels).) This section critiques EPA's basis for proposing the lignite Hg emission rate of 1.2 lbs/MBtu, while supporting the proposal to retain the existing rate for non-low rank coals.

EPA states the following in support of their proposal regarding lignite:

"…..ash from lignite and subbituminous coals tends to be more alkaline (relative to that from bituminous coal) due to the lower amounts of sulfur and halogen and the presence of a more alkaline and reactive (non-glassy) form of calcium in the ash. The natural alkalinity of the subbituminous and lignite fly ash can effectively neutralize the limited free halogen in the flue gas and prevent oxidation of the Hg^0.

Both lignite and subbituminous coal do contain less sulfur than bituminous coal, but other major differences in composition exist that EPA does not recognize. These are Hg content and its variability, the sulfur content, and the alkalinity of inorganic matter. EPA's failure to recognize these differences manifests itself as (a) assuming activated carbon sorbent effectiveness observed on subbituminous coal (specifically PRB) extends to lignite, and (b) ignoring variability in Hg content, as well as the role of sulfur trioxide (SO_3), which compromises achieving 90%+ Hg removal as required to attain 1.2 lbs/TBtu.

Fuel properties are described separately for the North Dakota and Gulf Coast (Texas and Mississippi) lignite mines.

6.1 North Dakota Mines and Generating Units

Figures 6-1 to 6-4 present data provided by lignite suppliers from North Dakota mines that describe the variability for Hg and other constituents key to Hg removal. These figures present data as a "box and whisker" plot, which portrays the mean value, the 25th and 75th percentile of the observed data, and the near-minimum (5%) and near-maximum (95%) extremities. Figure 6-1 shows the variability of Hg and Figure 6-2 the variability of sulfur content. Figure 6-3 shows variability of fuel alkalinity compared to sulfur content – specifically, the ratio of calcium (Ca) and sodium (Na) to sulfur – i.e., the (Ca + Na)/S metric.

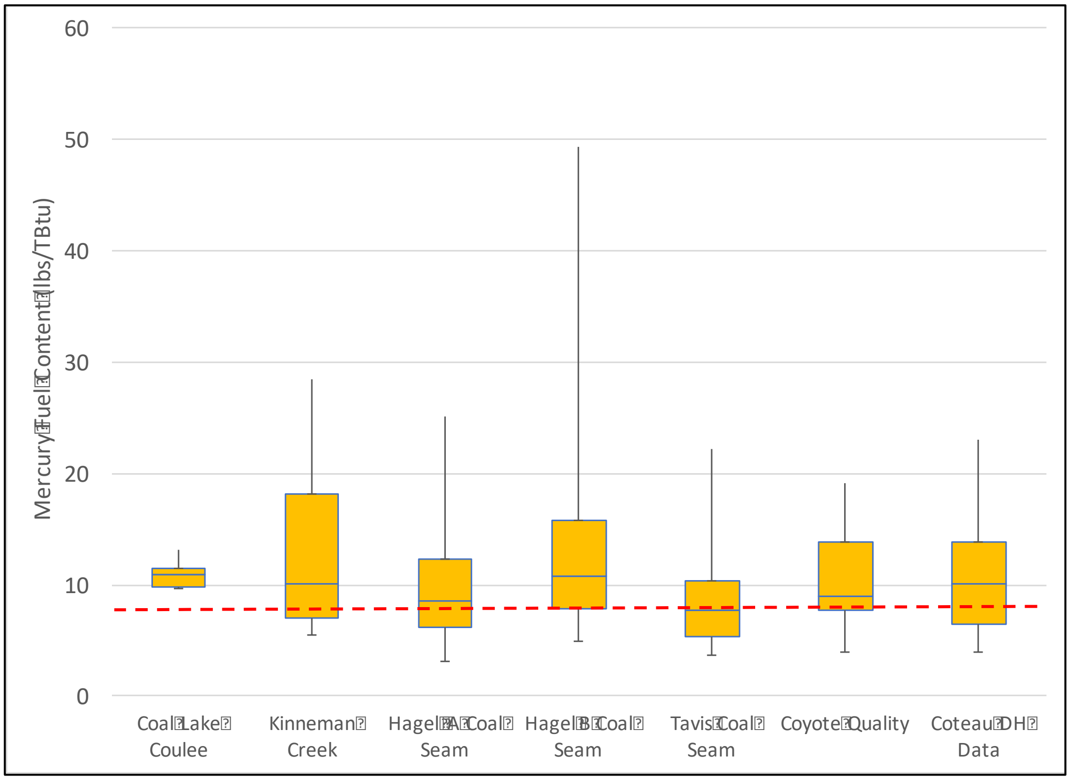

Figure 6-1. Mercury Content Variability for Eight North Dakota Lignite Mines

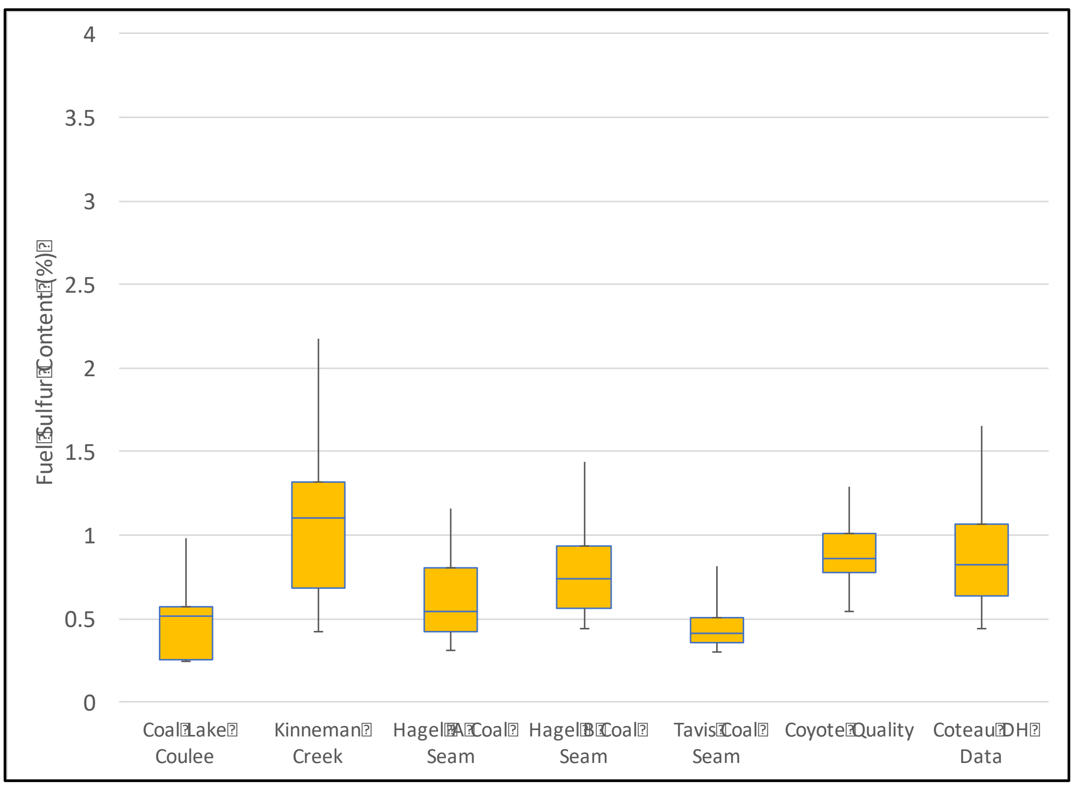

Figure 6-2. Fuel Sulfur Content Variability for Eight North Dakota Lignite Mines

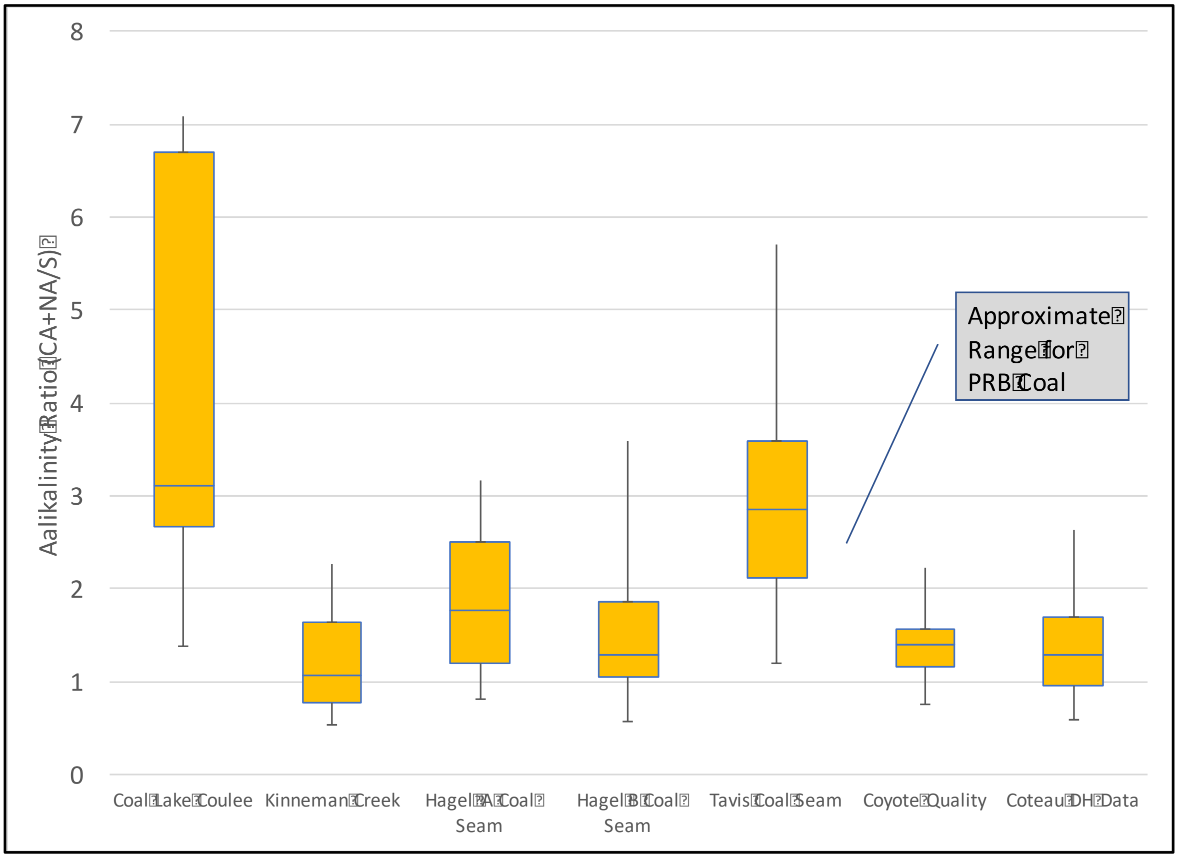

Figure 6-3. Fuel Alkalinity/Sulfur Ratio for Eight North Dakota Mines

Figure 6-1 compares the Hg content and variability to the fixed value of 7.7-7.8 lbs/TBu, assumed by EPA as representing North Dakota lignite, as summarized in Table 11 of the Tech Memo. Figure 6-1 shows – with the exception of the Tavis seam – all mean values of Hg content exceed EPA's assumed value that serves as the basis of EPA's evaluation. More notably, the 75th percentile value of Hg for each seam - slightly more than one standard deviation variance from the mean – in all cases significantly exceeds the value assumed by EPA.

Of note is that the variability of Hg depicted in Figure 6-1 is not necessarily observed only over extended periods of time – such as months or quarters – it can be witnessed over period of days or weeks. This is attributable to the sharp contrast in Hg content of seams that are geographically proximate and thus are mined within an abbreviated time period. Figure 6-4 presents a physical map showing the location of "boreholes" in a lignite field with imbedded text describing (in addition to the borehole code) the Hg content as ppm. The text boxes report this Hg content in terms of lbs/TBtu. These example boreholes – separated by typically 660 feet- and the factor of 3 to 6 variation of Hg content present a meaningful visualization of Hg variability in a lignite mine, and the consequences for the delivered fuel.

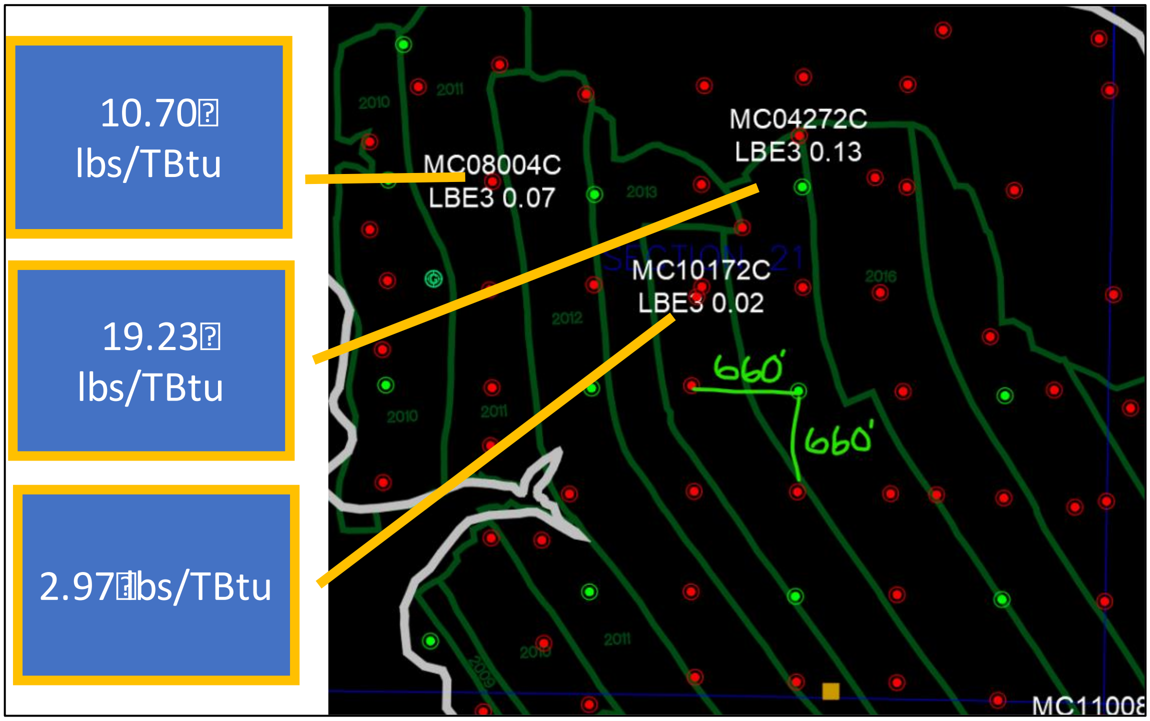

Figure 6-4. Spatial Variation of Hg in a Lignite Mine

Data from Figure 6-1 is summarized in Table 6-1 for units at four stations in North Dakota – Coal Creek, Antelope Valley, Coyote, and Leland Olds. Both Figures 6-1 and Table 6-1 show Hg variability exceed that assumed by EPA in their evaluation. Table 6-1 shows that achieving a 1.2 lbs/TBu requires an Hg removal rate of approximately 93-95% for unavoidable instances where coal Hg content is at the 95th percentile of observed value. The approximate 93-95% Hg removal requirements well exceed the 85% Hg removal based on the IPM-assigned Hg content.

Table 6-1. Hg Variability for Select North Dakota Reference Stations

Station	Mine	Seams	IPM Designated Hg Rate (lbs/TBtu)	Inferred EIA 2021 Hg Rate (lbs/TBtu)	Hg Fuel Content at 95^{th} Percentile (lbs/TBtu)	Hg Removal (%) for 1.2 lbs/TBtu at 95^{th} Percentile
Coal Creek	Falkirk	UTAV, HGB1 and HGA1/HGA2 (Mostly Haga A seam)	7.81	7.80	25.1	95.2
Antelope Valley	Freedom	Freedom Mine Belauh Seam	7.81	7.76	23.0	94.8
Coyote	Coyote Creek	Coyote Upper Belauh	7.81	7.79	19.2	93.8
Leland Olds	Freedom	Kinneman Creek, Hagel A, Hagel B	7.81	7.79	23.0	94.8

6.2 Texas Gulf Coast Mines and Generating Units

Figures 6-5 to 6-7 present data from Texas and Mississippi lignite mines describing the content and variability for Hg, sulfur, and the (Ca + Na)/S metric, as delivered to generating units in Texas. Analogous to the data cited for North Dakota, the "box and whisker" depiction represents the same metrics.

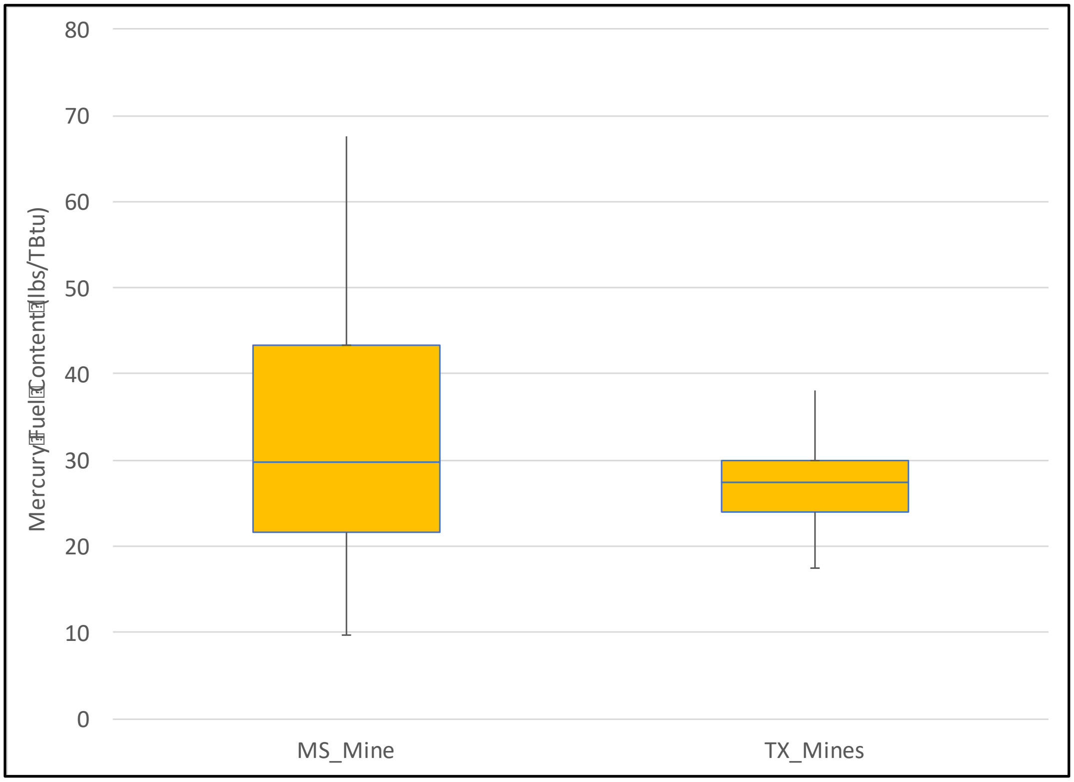

Figure 6-5. Mercury Variability for Two Gulf Coast Sources: Mississippi, Texas

Table 6-2 compares the Hg removal required to meet the proposed 1.2 lbs/TBtu rate considering the variability of Hg in Texas and Mississippi coals, instead of the IPM-assigned Hg coal content. For three Texas plants that fired 100% lignite – Major Oak Units 1 and 2, Oak Grove Units 1 and 2, and San Miguel – EPA assigned inlet Hg values from 12.44 to 14.88 lbs/TBtu, implying Hg removal of 90-92% to achieve 1.2 lbs/TBtu. However, based on the 95th percentile value of the Texas lignite Hg values from Figure 6-5, the required Hg removal would be 96-97%.

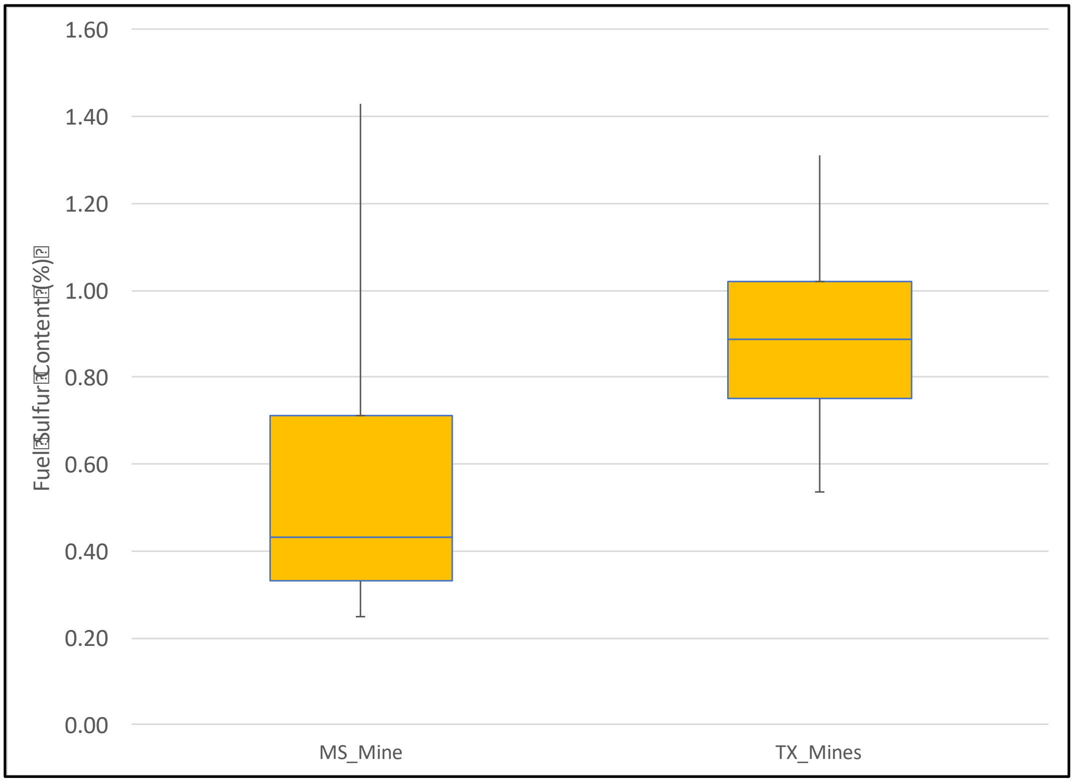

Figure 6-6. Sulfur Variability for Mississippi, Texas Lignite Mines19.1

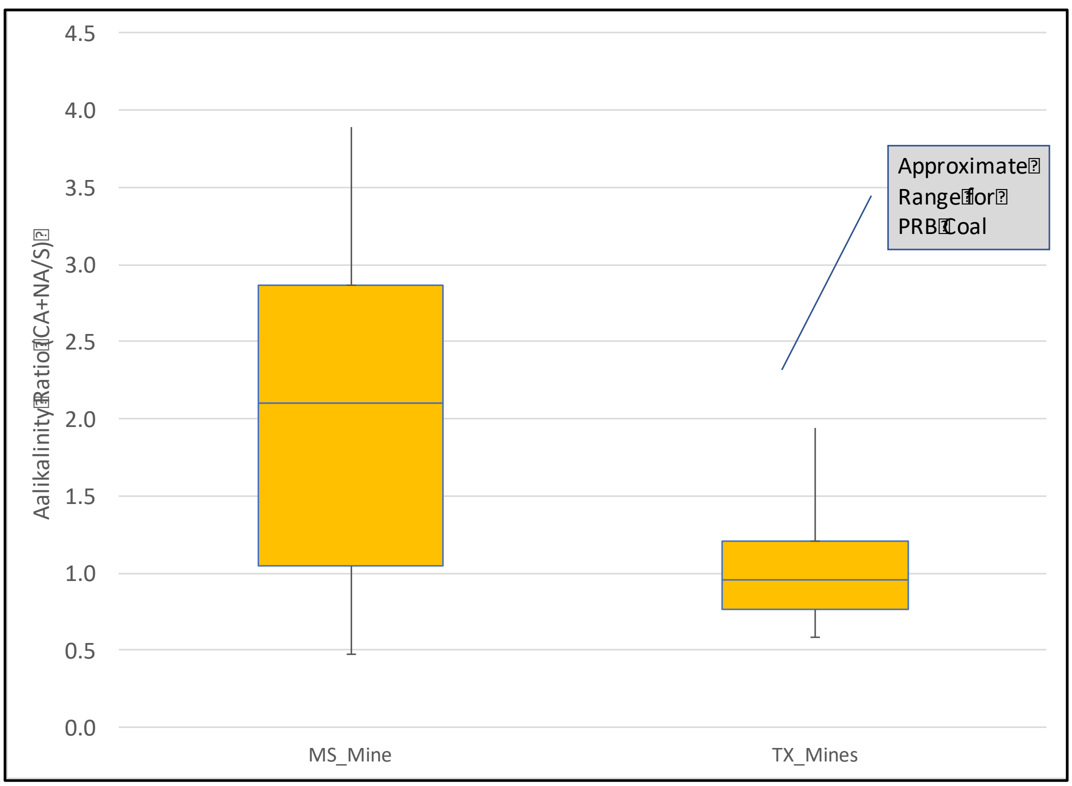

Figure 6-7. Fuel Alkalinity/Sulfur Ratio for Mississippi, Texas Lignite Mines

Table 6-2. Hg Variability for Select Texas Reference Stations

Station	Mines	IPM Designated Hg Rate (lbs/TBtu)	Inferred EIA 2021 Hg Rate (lbs/TBtu)	Hg Fuel Content at 95th Percentile (lbs/TBtu)	Hg Removal (%) for 1.2 lbs/TBtu at 95th Percentile
Major Oak 1,2	Calvert	14.65	14.62	38.12	96.9
Oak Grove 1, 2	Kosse Strip	14.88	14.6	38.12	96.9
Red Hills 1, 2	Red Hills	12.44	12.4	67.6	98.2
San Miguel	San Miguel Lignite	14.65	14.62	38.1	96.9

6.3 Role of Flue Gas SO3

EPA equates PRB and lignite coal in terms of constituents that affect Hg capture by carbon sorbent. Data from North Dakota and Gulf Coast mines, displayed in the previous Figures 6-1 to 6-7, show these fuels also contain higher sulfur content than PRB - by a factor or two or more. This relationship is verified by data acquired from EIA Form 960, as provided by power station owners. These fuel data, combined with inherent alkalinity, identifies the problematic role of flue gas SO_3 content.

6.3.1 EIA Hg-Sulfur Relationship

Figure 6-8 compares the seam-by-seam Hg and sulfur content from various power stations firing lignite coals, representing approximately 60 lignite mines and 40 PRB mines. Figure 6-8 shows, even excluding the outlier values of Hg (approximating 50 lbs/TBtu), lignite presents significantly greater variability in Hg and sulfur than PRB. Moreover, lignite coals have a much higher sulfur content than PRB and in many instances have twice the Hg content. The higher sulfur content of lignite equates to greater production rates of sulfur SO_3.

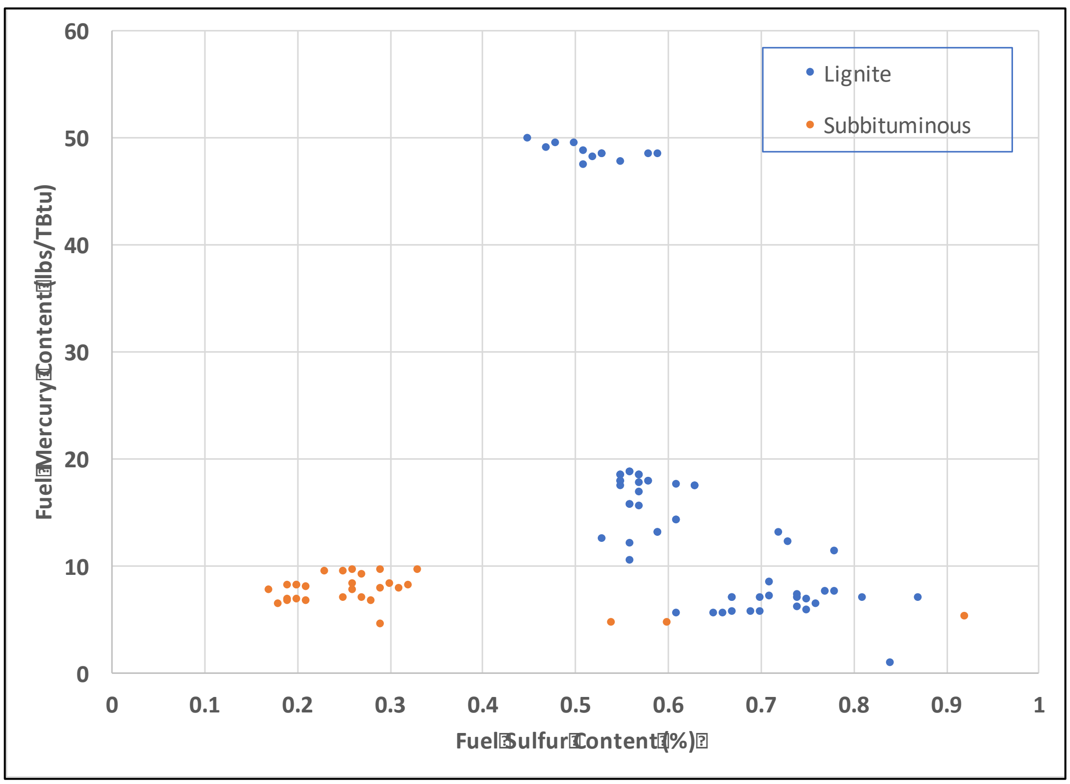

Figure 6-8. Lignite Hg and Sulfur Content Variability: 2021 EIA Submission

An additional factor is the amount of "inherent" alkalinity compared to sulfur – with higher value surpassing the SO_3 content in flue gas. As introduced previously, one metric of this feature is the ratio of Na and Ca to sulfur – on a mole basis.

Figures 6-3 and 6-7 show North Dakota and Gulf Coast lignite present a similar ratio of alkalinity to sulfur content as does PRB – approximating a value of 2. By this metric, lignite fuels in Figure 6-3 present similar means to "buffer" SO_3 as PRB. Notably, Texas lignite in Figure 6-7 is disadvantaged in this metric as the alkalinity to sulfur ratio is half that of PRB – reducing the buffering" effect of inherent ash.

Consequently, the higher sulfur content of lignite combined with equal or lower total alkali relative to sulfur allows measurable levels of SO_3 in lignite-generated flue gas, as evidenced by field measurements. EPA does not recognize this distinguishing difference, and states the following regarding lignite and subbituminous coal:[30]

As mentioned earlier, EGUs firing subbituminous coal in 2021 emitted Hg at an average annual rate of 0.6 lb Hg/TBtu with measured values as low as 0.1 lb/TBtu. Clearly EGUs firing subbituminous coal have found control options to demonstrate compliance with the 1.2 lb/TBtu emission standard despite the challenges presented by the low natural halogen content of the coal and production of difficult-to-control elemental Hg vapor in the flue gas stream.

This passage contains two major flaws – that the effectiveness of Hg removal techniques with PRB-generated flue gas can be replicated with lignite, and that average annual Hg emission rates are the metric for comparison. EPA fails to recognize that Hg removal in PRB is in the presence of very little (essentially unmeasurable) SO_3, and 30-day rolling averages exhibit variability not captured by the annual average.

6.3.2 SO_3: Inhibitor to Hg Removal

The ability of SO_3 to interfere with sorbent Hg removal is well-known.[31] Most notably, EPA's contractor for the technology assessments used in the IPM[32] – Sargent & Lundy –for EPA issued assessment on Hg control technology. This document states[33]

With flue gas SO3 concentrations greater than 5 - 7 ppmv, the sorbent feed rate may be increased significantly to meet a high Hg removal and 90% or greater mercury removal may not be feasible in some cases. Based on commercial testing, capacity of activated carbon can be cut by as much as one half with an SO3 increase from just 5 ppmv to 10 ppmv.

This passage from the S&L technology assessment – funded by EPA to support the IPM model - describes that Hg absorption capacity of carbon can be cut in half by an increase in SO_3 from 5 to 10 ppm. In addition, the presence of SO_3 asserts a secondary role in terms of gas temperature – units with measurable SO_3 are designed with higher gas temperature at the air heater exit – typically where sorbent is injected – to avoid corrosion. Special-purpose tests on a fabric filter

[30] Tech Memo page 21

[31] Sjostrom 2019. See graphics 21-25

[32] Documentation for EPA's Power Sector Modeling Platform v6: Using the Integrated Planning Model, May 2018.

[33] IPM Model – Updates to Cost and Performance for APC Technologies: Mercury Control Cost Development Methodology, Prepared by Sargent & Lundy, Project 12847-002, March 2013.

pilot plant showed an increase in gas temperature from 310ºF to 340ºF lowered sorbent Hg removal from 81% to 68%.[34] The role of SO_3 is not considered in assumed carbon injection rates for EPA's economic analysis in Tables 12 and 13 of the Tech Memo.

Publicly available field test data demonstrate the role of SO_3 on carbon sorbent effectiveness. Figure 6-9 presents results from a lignite-fired plant describing Hg removal across the ESP with sorbent injection.[35] This 900 MW unit is reported to fire a higher sulfur lignite in which more than 20 ppm of SO_3 in flue gas is observed preceding the air heater, subsequently decreasing to 10 ppm SO_3 existing the air heater.

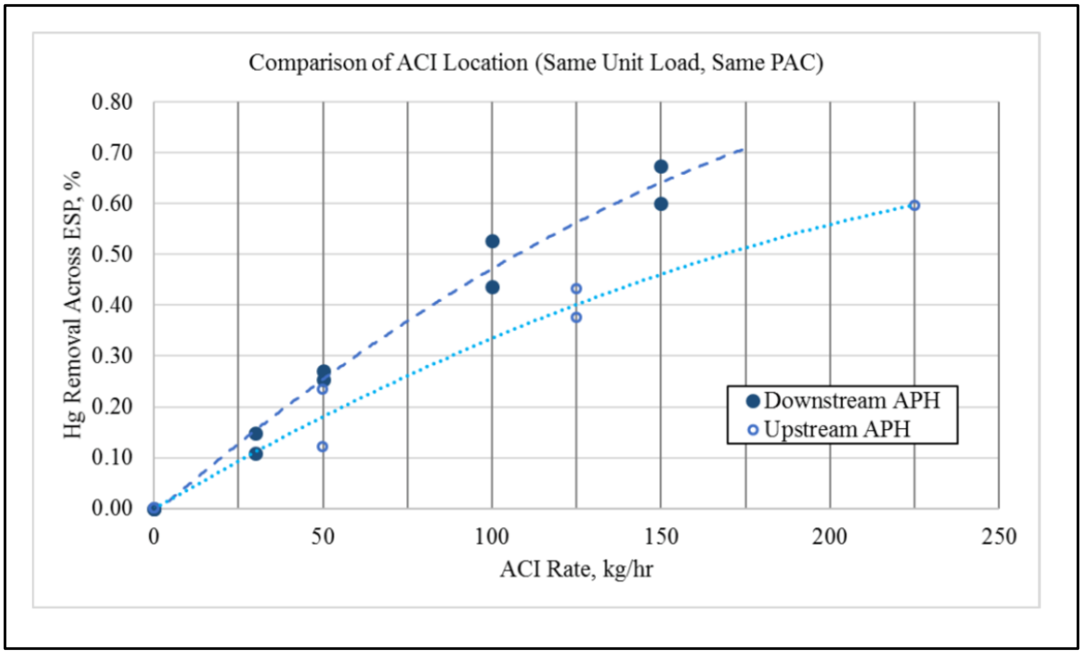

Figure 6-9. Sorbent Hg Removal in ESP in Lignite-Fired Unit: Effect of Injection Location

Data in Figure 6-9 show the role of SO_3 in compromising sorbent performance - highest Hg removal is attained with lower SO_3 (downstream APH) with 60-68% Hg removal achieved (at an injection rate corresponding to 0.6 lbs/MACF).

Attaining a total system 92% Hg removal – the target as described by EPA – is likely not achievable given the trajectory of the curves as shown in Figure 6-9.

6.4 EPA Cost Calculations Ignore FGD

EPA ignores the major role of wet or dry FGD in removing Hg – a fundamental flaw in their analysis. EPA's premise that sorbent addition is the sole compliance technology is incorrect – 18 of 22 units in the lignite fleet listed in Table 9 of the RTR Tech Memo are equipped with FGD.

[34] Sjostrom 2016. See graphic 16.

[35] Satterfield, J., Optimizing ACI Usage to Reduce Costs, Increase Fly Ash Quality, and Avoid Corrosion, presentation to the Powerplant Pollutant and Effluent Control Mega Symposium, August, 2018.

Of these 18 units, 4 are equipped with dry FGD and 14 with wet FGD. This process equipment asserts a major role in Hg removal as discussed in the next section.

The calculation of cost-effectiveness for the model plant as presented in Section (e)(i) of the RTR Tech memo addresses only sorbent addition, thus does not reflect the Hg compliance strategy of 18 units in the lignite fleet. EPA assumes (a) upgrade of sorbent from "conventional" activated carbon to the halogenated form, and (b) increasing sorbent injection from 2.5 to 5.0 lbs/MAFH elevates Hg reduction from 73% to 92%.[36] This assumption is not relevant – at least in this specific form – to 18 of 22 units in the lignite fleet, as wet or dry FGD will contribute to Hg removal. EPA's approach could underestimate the cost per ton incurred, as tons of Hg removed by the FGD could be credited to sorbent injection (the denominator of the $/ton calculation is larger than it should be).

The variable of FGD Hg removal cannot be ignored, and undermines the legitimacy of the cost estimates as Hg removed by FGD cannot be ascribed to sorbent injection. Thus, depending on how or if the sorbent injection rate changes, costs could increase beyond EPA's estimate (as the denominator in the $/ton calculation is reduced.

6.5 Conclusions

- EPA's proposal that Hg emissions of 1.2 lbs/TBtu can be attained for lignite-fired units by increasing sorbent injection rate and adding halogens (to compensate for loss of refined coal) is incorrect, as it assumes sorbent injection Hg removal observed with PRB is achievable on lignite.

- Flue gas generated from lignite exhibits measurable SO_3 in quantities that– as summarized by EPA's contractor for IPM model inputs - reduce the effectiveness of sorbent by 50% and in some cases presents a barrier to 90% Hg removal.

- Accounting for the variability of Hg content in lignite for most North Dakota and Texas lignite fuels, more than 90% Hg removal is required to meet 1.2 lbs/MBtu, exceeding the nominally 80% removal estimated by EPA, and over a 30-day rolling average basis is unlikely to be attained.

- EPA's calculation of cost–effectiveness for lignite fuels ignores the role of FGD, present in 18 of the 22 reference stations, in removing Hg. The result of this erroneous assumption could be an under-estimation of the cost for additional Hg removal.

[36] EPA uses the incorrect constant in the calculation of gas flow rate to translate sorbent injection from a mass per time basis (lb//hr) to mass per unit volume of gas (lbs/MACF). The calculation on page 24 uses the value of 9,860 scf/MBtu to quantify flue gas generated from lignite coal. Per EPA-454/R-95-015 (Procedure for Preparing Emission Factor Documents, OAQPS, November 1997) this value reflects the dry volume of gas produced from lignite coal, per MBtu. The flue gas rate that is processed by the environmental controls is the authentic "wet" basis and about 20% higher per MBtu (12,000 scf/MBtu). Use of the correct, latter constant lowers the value of sorbent per MACF by the same magnitude.

7. Mercury Emissions: Non-Low Rank Fuels

Section 7 addresses EPA's proposal to retain the present Hg limit of 1.2 lbs/TBtu for units firing bituminous and subbituminous coals.

EPA recognizes that Hg emission rates - as determined on an annual average basis - have decreased significantly since the initial MATS rule was issued, with bituminous–fired units averaging 0.4 lbs/TBtu (and ranging between 0.2 and 1.2 lbs/TBtu) and subbituminous-fired units averaging 0.6 lbs/TBtu (ranging between 0.1 to 1.2 lbs/TBtu).[37] EPA states these Hg emission rates represent between a 77 and 98% Hg removal from an assumed Hg inlet value of 5.5 lbs/TBtu. EPA notes they did not acquire detailed information on compliance steps such as the type of sorbent injected, the rate of sorbent injection, and the role of SCR NOx control and wet FGD and the myriad factors that determine Hg removal "co-benefits."

This section addresses the reported Hg removal and basis for EPA's position.

7.1 Hg Removal

EPA's discussion of the annual average of Hg removal does not consider the 30-day rolling average, the more challenging metric to attain – and the metric mandated for compliance. The 30-day rolling average reflects variability in Hg coal content and process conditions, both of which can experience daily or hourly changes, which obviously is not captured in annual averages.

Figures 7-1 and 7-2 report two metrics of Hg emission rate variability.[38] Figure 7-1 presents the mean and standard deviation of Hg annual average emissions for eleven categories of control technology and fuel rank. For six of these eleven categories, the sum of the mean and the standard deviation approach the Hg limit of 1.2 lbs/TBtu.

Figure 7-2 describes for six categories of control technology and 2 or 3 fuel ranks (depending on the technology) the number of units that for at least one operating day exceed 1.2 lbs/TBtu on a 30-day rolling average. Figure 7-2 shows for all categories of control technology and fuel rank experience 10% to 20% of units exceed this 30-day average.

In summary, EPA's report of annual Hg emission rate - significantly reduced compared from 2012 – does not provide a basis for further reductions as annual data does not account for variability.

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[37] Prepublication Version, page 85

[38] Cichanowicz, J. E. et. al., Mercury Emissions Rate: The Evolution of Control Technology Effectiveness, Presented at the Power Plant Pollutant and Effluent Control MEGA Symposium: Best Practices and Trends, August 20-23, 2018, Baltimore, MD.

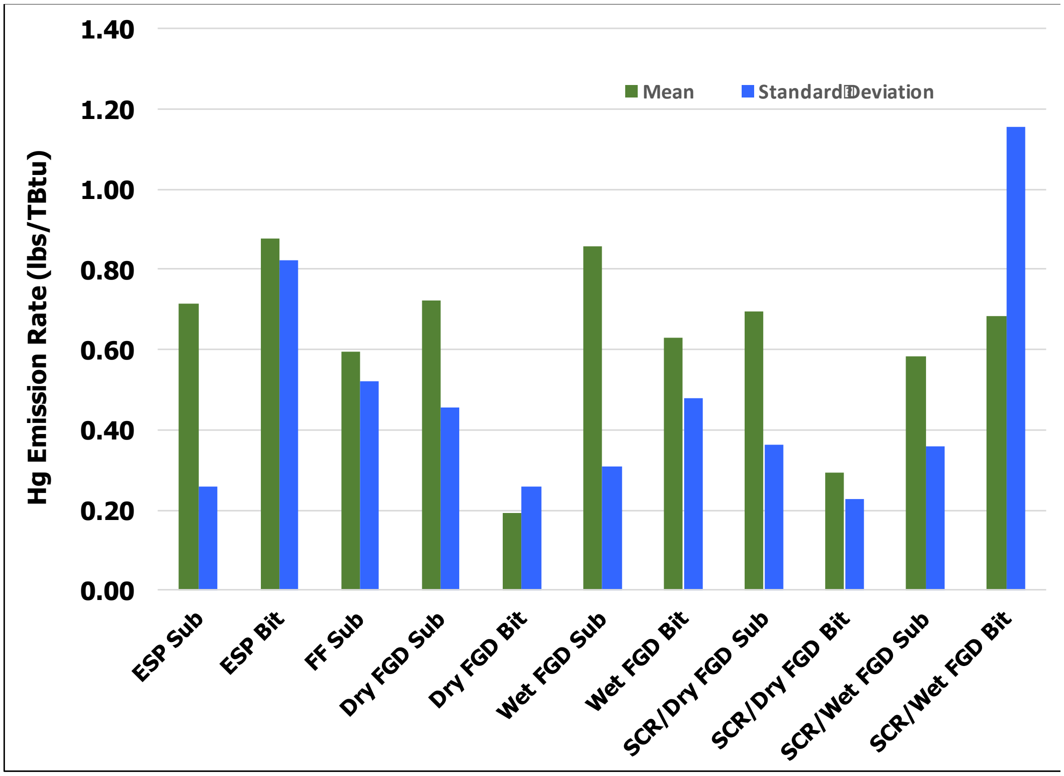


Figure 7-1. Mean, Standard Deviation of Annual Hg Emissions: 2018

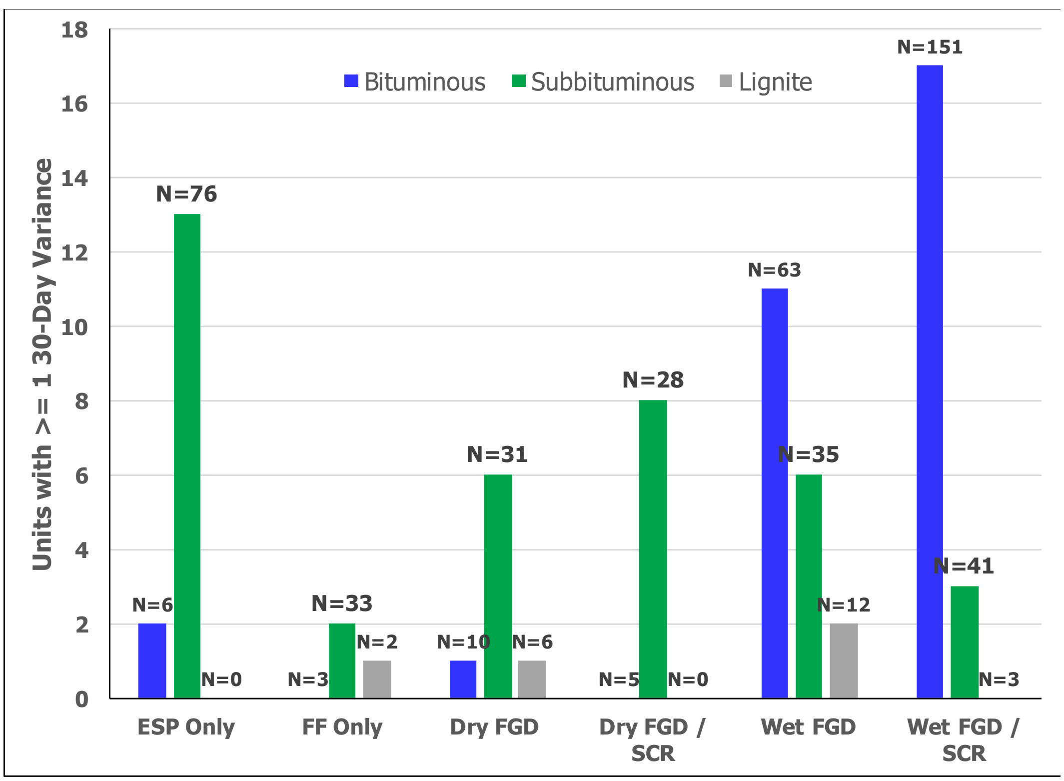


Figure 7-2. Mean, Standard Deviation of Annual Hg Emissions: 2018

7.2 Role of Fuel Composition and Process Conditions

Hg emissions are defined by variability in coal composition and process conditions, the latter including sorbent type, and injection rate, and the "co-benefit" Hg removal imparted by SCR NOx control and wet or dry FGD.

Although EPA did not elicit detailed process information from owners via Section 114, several key insights are presented in a 2018 survey conducted by ADA.[39]

7.2.1 Coal Variability

EPA cites observing for Hg emissions "a control range of 98 to 77 percent (assuming an average inlet concentration of 5.5 lb/TBtu)."[40] It is not clear if EPA assigns the average Hg content value of 5.5 lbs/TBtu to both bituminous and subbituminous coal, or solely the latter.

Figure 7-3 shows an average value of 5.5 lbs/TBtu does not represent either coal rank well. Figure 7-3 presents – on an annual average basis – data from more than 70 units reporting Hg content to the EIA. Numerous units report up to 10 lbs/TBtu - almost twice the average value EPA assigns, with 10 additional units reporting Hg content exceeding 10 lbs/TBtu. Northern Appalachian bituminous coals appear to contain higher Hg content than coals from other regions.

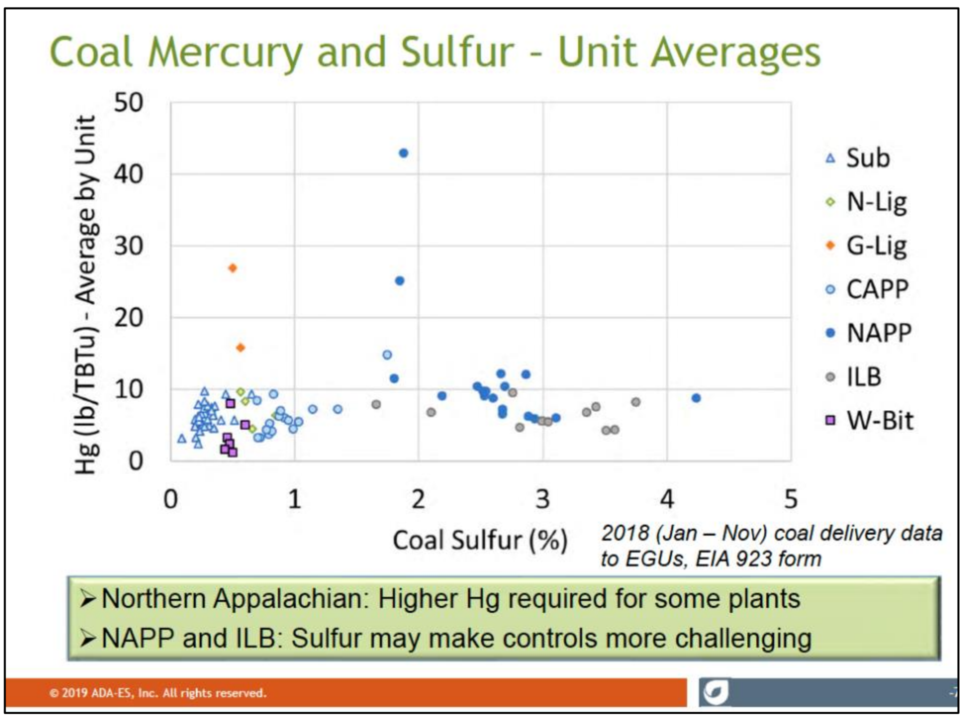


Figure 7-3. Annual Average of Fuel Hg, Sulfur Content in Coal

[39] Sjostrom, S. et. al., Mercury Control in the U.S.: 2018 Year in Review

[40] RTR Tech Memo, page 19.

Consequently, EPA's calculation of 98 to 77% Hg removal is likely inaccurate as the assumed coal Hg content is too low.

7.2.2 Process Conditions

The process conditions for Hg removal: sorbent composition, sorbent injection rate, and the "co-benefits" of SCR NOx control and wet FGD are highly variable, due to a combination of factors. The following provides several examples.

Refined Coal. The absence of Refined Coal – no longer a viable option - complicates projecting future Hg emissions. A survey of Hg compliance activities for 2018 reported Refined Coal as a compliance step;[41] EIA fuel records show this trend persisted through 2021. EPA's assumption that adding halogens to the fuel or flue gas compensates for the unavailability of Refined Coal is speculative and without basis. *Without assurances of the benefits from the halogen content of Refined Coal, it is not possible to assess the viability of lowering Hg emissions*.

Sorbent Injection. Sorbent injection is a key compliance step for 70% of subbituminous-fired units, for some augmented with coal additives and Refined Coal. For bituminous-fired units, 18% of coal use is treated by some combination of sorbent injection and coal additives.

As described by EPA, increasing the rate of sorbent injection increases Hg removal – but with diminishing returns as sorbent mass is added. An example of this relationship is provided by full-scale tests at Ameren's PRB-fired Labadie Unit 3. These tests explored the effectiveness of both conventional and brominated activated carbon. These tests, purposely conducted in PRB-generated flue gas to define sorbent performance in the absence of SO_3, show Hg removal of 90% or more is feasible and that halogen addition can lower sorbent rate.[42]

This relationship is complicated by the role of Refined Coal, coal additives, and (as described below) the contribution of "co-benefits". *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.*

SCR, FGD Co-Benefits. The capture of Hg by wet FGD – in many cases prompted by the role of SCR catalysts to oxidize elemental Hg – can be a primary mean for Hg capture. However, such co-benefits are highly variable, and depend on the ratio of elemental to oxidized Hg in the flue gas, and the consequential Hg "re-emission" by a wet FGD. There are means to remedy this variability in some instances, but broad success cannot be assured. *Without the specifics of FGD design and operation, Hg removal via wet FGD cannot be predicted.*

[41] Sjostrom, S. et. al., Mercury Control in the U.S.: 2018 Year in Review. Hereafter Sjostrom 2019.

[42] 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.

Hg Re-Emission. The fate of Hg entering a wet FGD is uncertain.[43] If in the oxidized state, Hg upon entering the FGD solution can (a) remain in solution and be discharged with the FGD-cleansing step of "blowdown" (b) precipitate as a solid and be removed with the byproduct (typically gypsum), or (c) be reduced from the oxidized to the elemental state, thus re-emitted in the flue gas. Several means to minimize Hg re-emission exist, including injection of sulfite and controlling the scrubber liquor oxidation/reduction potential (ORP). These means can limit Hg remission but are additional process steps that are superimposed upon the task of achieving high efficiency SO_2 removal. *The extent these means can be universally applied without compromising SO_2 removal is uncertain.*

Role of Variability Due to Load Changes. An in-plant study showed that increasing load for a wet FGD-equipped unit can elevate Hg re-emission, eventually exceeding 1.2 lbs/TBtu.[44] This observation can be due to loss of the control over the ORP, defined in the previous paragraph as a key factor in FGD Hg removal. Chemical additives can adjust ORP but complete and autonomous control may not be available. For example, in a systematic evaluation of FGD operating variables conducted at a commercial power station, factors such as limestone composition and the extent to which units must operate in zero-water discharge – as perhaps mandated by the pending Effluent Limitation Guideline – can affect ORP and thus Hg-re-emission.[45]

Upsets in wet FGD process conditions can prompt Hg re-emission. Specifically, one observer noted two units that "….experienced a scrubber reemission event causing the mercury stack emissions to increase dramatically above the MATS limit and significantly higher than the incoming mercury in the coal and the event lasting for several days."[46] This high Hg event was eventually remedied over the short-term operation, but long-term performance is not available.

7.3 Conclusions: Mercury Emissions - Non-Low Rank Coals

There is inadequate basis to further lower the Hg emissions rate below the present limit of 1.2 lbs/TBtu, as variability in fuel and process operations outside the control of the operator can elevate emissions to approach or in some cases exceed that rate.

[43] Gadgil, M., 20 Years of Mercury Re-emission – What do we Know?, Presentation to the Power Plant Pollutant Control and Carbon Management Mega Symposium, August 16-18, 2016.
[44] Blythe, G. et. al., Maximizing Co-Benefit Mercury Capture for MATS Compliance on Multiple Coal-Fired Units, Presentation to the Power Plant Pollutant Control and Carbon Management Conference Mega Symposium, August 16-18, 2016.
[45] Blyte, G. et. al., Investigation of Toxics Control by Wet FGD Systems, Presentation to the Power Plant Pollutant Control and Carbon Management Conference Mega Symposium, August 16-18, 2016.
[46] Pavlisch, J. et. al., Managing Mercury Reemission and Managing MATS compliance Using a sorbent Approach, Presentation to the Power Plant Pollutant Control and Carbon Management Conference Mega Symposium, August 16-18, 2016.

8. EPA IPM RESULTS: EVALUATION AND CRITIQUE

EPA used the Integrated Planning Model (IPM) to establish a Baseline Scenario from which to measure compliance impacts of the proposed rule. This Baseline Scenario is premised upon IPM's Post-IRA 2022 Reference Case. In this Post-IRA simulation, IPM evaluated a number of tax credit provisions of the Inflation Reduction Act of 2022 (IRA), which address application of Carbon Capture and Storage (CCS) and other means to mitigate carbon dioxide (CO_2). These are the (i) New Clean Electricity Production Tax Credit (45Y); (ii) New Clean Electricity Investment Credit (48E); Manufacturing Production Credit (45X); CCS Credit (45Q); Nuclear Production Credit (45U); and Production of Clean Hydrogen (45V). Also, the Post-IRA 2022 Reference Case includes compliance with the proposed Good Neighbor Policy (Transport Rule).[47]

A critique of EPA's methodology and findings is described subsequently.

8.1 IPM 2030 Post-IRA 2022 Reference Case: A Flawed Baseline

The IPM Post-IRA 2022 Reference Case for the years 2028 and 2030 comprises a flawed baseline to measure compliance impacts of the proposed rule. This flawed baseline centers around IPM projected coal retirements in both 2028 and 2030 as well as units projected to deploy CCS in 2030. Specifically, IPM has erroneously retired numerous coal units expected to operate beyond 2028 and 2030 based upon current announced retirement plans; consequently, these units are subject to the proposed rule beginning in 2028. There are numerous challenges and limitations to deploying CCS as EPA has projected on 27 coal units in 2030. These units would also be subject to the proposed. Consequently, IPM's compliance impacts of the proposed rule is likely understated.

8.1.1 Analytical Approach

This analysis identifies those units IPM modeled as coal retirements, CCS retrofits and coal to gas (C2G) conversions in both 2028 and 2030, and compares them to announced plans for unit retirements, technology retrofits and C2G conversions. To identify errors for 2028, the parsed file for the 2028 Post-IRA 2022 Reference Case was used. Since EPA did not provide a parsed

[47] In addition to the IRA and GNP, the Post-IRA 2022 Reference Case takes into account compliance with the following: (i) Revised Cross-State Air Pollution Rule (CSAPR) Update Rule; (ii) Standards of Performance for Greenhouse Gas Emissions from New, Modified and Reconstructed Stationary Sources: Electric Utility Generating Units; (iii) MATS Rule which was finalized in 2011; (iv) Various current and existing state regulations; (v) Current and existing RPS and Current Energy Standards; (vi) Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART); and, (vii) Platform reflects California AB 32 and RGGI. Three non-air federal rules affecting EGUs: (i) Cooling Water Intakes (316(b) Rule; (ii) Coal Combustion Residuals (CCR), which reflects EPA's July 29, 2020 position on retrofitting or closure of surface impoundments; and, (iii) Effluent Limitation Guidelines, which includes the 2020 Steam Electric Reconsideration Rule (cost adders were applied starting in 2025).

file of the 2030 Post-IRA 2022 Reference Case, an abbreviated parsed file was created using four different IPM files. These are: (i) 2028 parsed file of the Post-IRA 2022 Reference Case; (ii) Post-IRA 2022 Reference Case RPE File for the year 2030; (iii) Post-IRA 2022 Reference Case RPT Capacity Retrofits File for the year 2030; and, (iv) National Electrical Energy Data System (NEEDS) file for the Post-IRA 2022 Reference Case. These parsed files allow identifying IPM modeled retirements in 2028 and 2030, CCS retrofits in 2030 and C2G in both 2028 and 2030. These modeled retirements and conversions were compared to announced information in the James Marchetti Inc ZEEMS Data Base.

8.1.2 Coal Retirements

The 2028 IPM modeling run retired 112 coal units (53.6 GW) from 2023 to 2028. In the 2030 analysis, IPM retired an additional 52 coal units (25.5 GW). The total number of retirements for the two modeling run years is 164 coal units (79.1 GW).

Table 8-1 summarizes the IPM retirement errors in the 2028 and 2030 modeling runs. Specifically, IPM incorrectly retired 29 coal units (14.0 GW) by 2028 and an additional 23 coal units (14.1 GW) in 2030. In addition, there are 3 coal units (1.6 GW) that EPA listed in the NEEDS file as being retired before 2028 that will operate beyond 2030. In total, there are 55 coal units that IPM erroneously retired in the 2028 and 2030 modeling runs that will be operating and subject to some aspect of the proposed rule beginning in 2028.

Table 8-1. Coal Retirement Errors

Year	Description	Number
2028	Retiring after 2028	29
2030	Retiring after 2030	23
2030	NEEDS retirements that should be in the 2030 modeling platform	3
Total		55

Tables 8-2 to 8-6 lists each of the coal units IPM has incorrectly retired, incorrectly deployed CCS, or switched to natural gas.

Table 8-2. IPM Coal Retirement Errors: 2028 Post-IRA 2022 Reference Case Run

No.	RegionName	StateName	ORISCode	UnitID	PlantName	Capacity	Observation
1	WECC_Arizona	Arizona	6177	U1B	Coronado	380	To be retired by 2032 and continued seasonal curtailemts,
2	SPP West	Arkansas	6138	1	Flint Creek	528	Retire January 1, 2039 Entergy LL 2023 IRP (March 31, 2023).
3	MISO_Arkansas	Arkansas	6641	1	Independence	809	Agreement with Sierra Club and NPCA to cease coal by Dec 31, 2030.
4	MISO_Arkansas	Arkansas	6641	2	Independence	842	Agreement with Sierra Club and NPCA to cease coal by Dec 31, 2030.
5	SERC_Central_TVA	Kentucky	1379	2	Shawnee	134	TVA planning assumption retirement (5/21) December 31, 2033
6	SERC_Central_TVA	Kentucky	1379	3	Shawnee	134	TVA planning assumption retirement (5/21) December 31, 2033
7	SERC_Central_TVA	Kentucky	1379	5	Shawnee	134	TVA planning assumption retirement (5/21) December 31, 2033
8	SERC_Central_TVA	Kentucky	1379	6	Shawnee	134	TVA planning assumption retirement (5/21) December 31, 2033
9	SERC_Central_TVA	Kentucky	1379	7	Shawnee	134	TVA planning assumption retirement (5/21) December 31, 2033
10	SERC_Central_TVA	Kentucky	1379	8	Shawnee	134	TVA planning assumption retirement (5/21) December 31, 2033
11	SERC_Central_TVA	Kentucky	1379	9	Shawnee	134	TVA planning assumption retirement (5/21) December 31, 2033
12	MISO_Minn/Wisconsin	Minnesota	6090	3	Sherburne County	876	PSC approved closure (2/8/22). Upper Midwest Resource Plan (6/25/21) for 2030.
13	MISO_Missouri	Missouri	2103	1	Labadie	593	2022 IRP Update retire in 2042 (6/24/22).
14	MISO_Missouri	Missouri	2103	2	Labadie	593	2022 IRP Update retire in 2042 (6/24/22).
15	MISO_Missouri	Missouri	2103	3	Labadie	593	2022 IRP Update (6/24/22) retirement in 2036
16	MISO_Missouri	Missouri	2103	4	Labadie	593	2022 IRP Update (6/24/22) retirement in 2036
17	MISO_Missouri	Missouri	2107	1	Sioux	487	2022 IRP Update (6/24/22) To be retired in 2030
18	MISO_Missouri	Missouri	2107	2	Sioux	487	2022 IRP Update (6/24/22) To be retired in 2030
19	SERC_VACAR	North Carolina	2712	3A.3B	Roxboro	694	2022 Carbon Reduction Plan per PSC retirement Jan. 1, 2028-34 (12/30/22).
20	SERC_VACAR	North Carolina	2712	4A, 4B	Roxboro	698	2023 Carbon Reduction Plan per PSC retirement Jan. 1, 2028-34 (12/30/22).
21	ERCOT_Rest	Texas	298	LIM1	Limestone	831	EIA 860 has retirement December 2029
22	ERCOT_Rest	Texas	298	LIM2	Limestone	858	EIA 860 has retirement December 2029
23	WECC_Utah	Utah	7790	1-1	Bonanza	458	Unit is planned to retire in 2030,
24	WECC_Utah	Utah	8069	2	Huntington	450	Retire in 2032 2023 IRP (3/31/23)
25	PJM_Dominion	Virginia	7213	1	Clover	440	Dominion 2023 IRP Retirement Date 2040 (5/1/23)
26	PJM_Dominion	Virginia	7213	2	Clover	437	Dominion 2023 IRP Retirement Date 2040 (5/1/23)
27	PJM_AP	West Virginia	3943	1	Fort Martin	552	EPA Settlement on wastewater upgrades (8/9/22). 2020 IRP through 2035
28	PJM_AP	West Virginia	3943	2	Fort Martin	546	EPA Settlement on wastewater upgrades (8/9/22). 2020 IRP through 2036
29	WECC_Wyoming	Wyoming	6101	BW91	Wyodak	332	Retire in 2039 IRP (3/31/23)

Table 8-3. IPM Coal Retirement Errors: 2030 Post IRA 2022 Reference Case Modeling Run

No.	RegionName	StateName	ORISCode	UnitID	PlantName	Capacity	Observations
1	WECC_Arizona	Arizona	6177	U2B	Coronado	382	To be retired by 2032 and contined seasonal curtailments
2	FRCC	Florida	628	4	Crystal River	712	To be retired in 2034 (2020 Sustainability Report)
3	FRCC	Florida	628	5	Crystal River	710	To be retired in 2034 (2020 Sustainability Report)
4	SERC_Southeastern	Georgia	6257	1	Scherer	860	ELG Compliance - Wastewater Treatment - No Announced Retirement
5	SERC_Southeastern	Georgia	6257	2	Scherer	860	ELG Compliance - Wastewater Treatment - No Announced Retirement
6	PJM West	Indiana	1040	1	Whitewater Valley	35	Biased to peak load duty. 2020 IRP Base Case has retirement May 31, 2034
7	MISO_Iowa	Iowa	1167	9	Muscatine Plant #1	163	ELG compliance options for FGDW and BATW, possible 2028 retirement
8	SPP North	Kansas	6068	1	Jeffrey Energy Center	728	To be retired at the end of 2039 (2021 IRP)
9	SPP North	Kansas	1241	2	La Cygne	662	To be retired at the end of 2039 (2021 IRP)
10	SERC_Central_Kentucky	Kentucky	1356	1	Ghent	474	To be retired 2034
11	SERC_Central_Kentucky	Kentucky	1356	3	Ghent	485	To be retired 2037.
12	SERC_Central_Kentucky	Kentucky	1356	4	Ghent	465	To be retired 2037.
13	SPP North	Missouri	6065	1	Iatan	700	To be retired at the end of 2039 (2021 IRP)
14	SPP North	Missouri	6195	1	John Twitty	184	Beyond 2030 retirement date - new 2022 IRP
15	SERC_VACAR	North Carolina	8042	1	Belews Creek	1110	1/1/2036 retirement per 2022 Carbon Reduction Plan
16	SERC_VACAR	North Carolina	8042	2	Belews Creek	1110	1/1/2036 retirement per 2022 Carbon Reduction Plan
17	SERC_VACAR	North Carolina	2727	3	Marshall (NC)	658	2022 Carbon Reduction Plan accepted by PSC retirement Jan. 1, 2033 (12/30/22)
18	SERC_VACAR	North Carolina	2727	4	Marshall (NC)	660	2022 Carbon Reduction Plan accepted by PSC retirement Jan. 1, 2033 (12/30/22)
19	MISO_MT, SD, ND	North Dakota	8222	B1	Coyote	429	Active per reliablity concerns in MISO. End of depreciable life - 2041
20	SERC_VACAR	South Carolina	6249	1	Winyah	275	2023 IRP: operate unit through 2030 for reliability (4/19/23)
21	SERC_VACAR	South Carolina	6249	2	Winyah	285	2024 IRP: operate unit through 2030 for reliability (4/19/23)
22	SERC_VACAR	South Carolina	6249	3	Winyah	285	2025 IRP: operate unit through 2030 for reliability (4/19/23)
23	SERC_VACAR	South Carolina	6249	4	Winyah	285	2026 IRP: operate unit through 2030 for reliability (4/19/23)
24	PJM West	West Virginia	3935	1	John E Amos	800	Approved ELG upgrades to keep plant open until 2040.
25	PJM West	West Virginia	3935	2	John E Amos	800	Approved ELG upgrades to keep plant open until 2040.
26	PJM_AP	West Virginia	3954	1	Mt Storm	554	Dominion 2023 IRP - Retirement Date 2044 (5/1/23)
27	PJM_AP	West Virginia	3954	2	Mt Storm	555	Dominion 2023 IRP - Retirement Date 2044 (5/1/23)

Table 8-4 Units in the NEEDS to Be Operating in 2028

No.	Region Name	State Name	ORIS Plant	Unit ID	Plant Name	Capacity (MW)	NEEDS Retirement Year	Observations
1	SPP_N	Kansas	1241	1	La Cygne	736	2025	2022 IRP Update to be retired in 2032
2	MIS_LA	Louisiana	6190	3-1, 3-2	Brame Energy Center	626	2027	No plans to retire. Evaluating CCS
3	WECC_WY	Wyoming	4158	BW44	Dave Johnston	330	2027	Retire in 2039 - 2023 IRP (3/31/23).

Table 8-5 Units IPM Predicts CCS By 2030

No.	Region Name	StateName	ORISCode	UnitID	PlantName	Capacity	Observations
1	ERCOT_Rest	Texas	6179	3	Fayette Power Project	286.05	
2	ERCOT_Rest	Texas	7097	BLR2	J K Spruce	537.93	Board voted to convert to natural gas by 2027 (1/23/23)
3	ERCOT_Rest	Texas	6180	1	Oak Grove (TX)	572.77	
4	ERCOT_Rest	Texas	6180	2	Oak Grove (TX)	570.97	
5	ERCOT_Rest	Texas	6183	SM-1	San Miguel	237.74	
6	FRCC	Florida	645	BB04	Big Bend	292.27	
7	MISO_Indiana	Indiana	6113	1	Gibson	594.24	
8	PJM West	Kentucky	6018	2	East Bend	399.00	
9	PJM West	West Virginia	3948	1	Mitchell (WV)	537.77	
10	PJM West	West Virginia	3948	2	Mitchell (WV)	537.77	
11	SERC_Southeastern	Alabama	6002	4	James H Miller Jr	477.05	
12	SPP_WAUE	North Dakota	6469	B1	Antelope Valley	289.22	
13	SPP_WAUE	North Dakota	6469	B2	Antelope Valley	288.38	
14	SPP_WAUE	North Dakota	2817	2	Leland Olds	279.16	
15	WECC_Arizona	Arizona	8223	3	Springerville	281.05	
16	WECC_Arizona	Arizona	8223	4	Springerville	281.05	
17	WECC_Colorado	Colorado	470	3	Comanche (CO)	501.15	To be retired Dec 31 2030 (10/31/22)
18	WECC_Colorado	Colorado	6021	C3	Craig (CO)	305.66	To be retired Dec 2029 - Electric Resource Plan (12/1/20)
19	WECC_Utah	Utah	6165	1	Hunter	319.80	Retire in 2031 - 2023 IRP (3/31/23)
20	WECC_Utah	Utah	6165	2	Hunter	292.44	Retire in 2032 - 2023 IRP (3/31/23).
21	WECC_Utah	Utah	6165	3	Hunter	314.06	Retire in 2032 - 2023 IRP (3/31/23).
22	WECC_Utah	Utah	8069	1	Huntington	311.54	Retire in 2032 - 2023 IRP (3/31/23).
23	WECC_Wyoming	Wyoming	8066	BW73	Jim Bridger	354.02	Convert to natural gas in 2030 - 2023 IRP (3/31/23)
24	WECC_Wyoming	Wyoming	8066	BW74	Jim Bridger	349.78	Convert to natural gas in 2030 - 2023 IRP (3/31/23)
25	WECC_Wyoming	Wyoming	6204	1	Laramie River Station	385.22	
26	WECC_Wyoming	Wyoming	6204	2	Laramie River Station	382.92	
27	WECC_Wyoming	Wyoming	6204	3	Laramie River Station	383.45	

Table 8-6 Units IPM Erroneously Predicts Switch to Natural Gas

No.	RegionName	StateName	ORISCode	UnitID	PlantName	Year	Capacity	Observations
1	SPP West (Oklahoma,	Arkansas	56564	1	John W Turk Jr Power Plant	2030	609	Retire Jan 1, 2068 - SWEPCO 2023 IRP (March 29, 2023)
2	PJM West	Kentucky	6041	2	H L Spurlock	2028	510	No announced C2G or co-firing
3	ERCOT_Rest	Texas	56611	S01	Sandy Creek Energy Station	2030	933	No announced conversion

8.1.3 Coal CCS

Table 8-5 identifies the 27 units IPM projected to retrofit CCS by 2030; none of these have been involved in any Front-End Engineering and Design (FEED) Studies. However, 9 of the units identified by IPM will be either be retired or converted to natural gas in and around 2030. There are major questions addressing infrastructure and project implementation that present challenges to IPM's CCS projection for 2030. Indeed, it is next to impossible for these units to be in position to retrofit CCS by 2030.

8.1.4 Coal to Gas Conversions (C2G)

The 2028 IPM modeling run converted 36 coal units to gas (14.3 GW). In the 2030 IPM modeling run an additional 2 coal units (1.5 GW) were converted to gas (Turk and Sandy Creek). As shown in Table 8.6, three of these units have no announced plans to convert to gas by 2028 or 2030 and will be subject to the proposed rule.

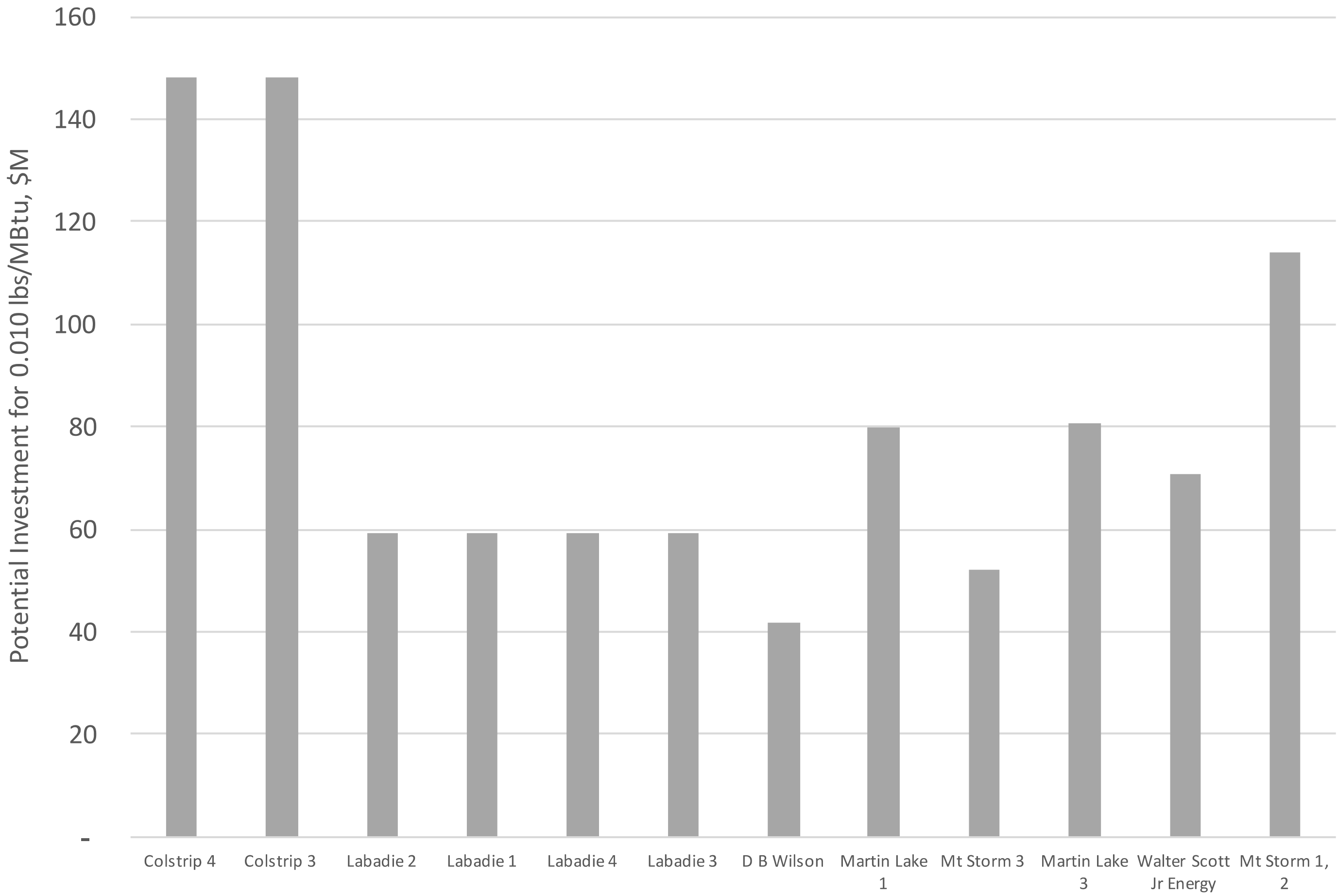
8.2 Summary

The major issues associated with EPA's IPM modeling of the 2028 and 2030 Post-IRA 2022 Reference Case are summarized as follows:

- The 2028 and 2030 Baseline (Post-IRA 2022 Reference Case) used to measure the compliance impacts of proposed rule is flawed and needs to be revised
- Most notably, IPM erred in retiring 55 coal units that will be subject to the proposed rule beginning in 2028.
- IPM retrofitted 27 units with CCS in 2030, 19 of which will be subject to the proposed rule. It is next to impossible for these units to retrofit CCS by 2030.
- The IPM modeled compliance impacts for the proposed rule in 2028 and 2030 is very likely understated.

Appendix A: Additional Cost Study Data

Figure A-1. Unit ESP Investment (per EPA's Cost Assumptions): PM of 0.010 lbs/MBtu



Note: Colstrip costs reflect EPA's approch of retrofitting a fabric filter, as an ESP is not installed at that site.

Table A-1. Technology Assignment for 0.010 lbs/MBtu PM Rate: Industry Study

ESP Minor	ESP Typical	ESP Major Upgrade	FF Cleaning	FF Retrofit
Alcoa/Warrick	East Bend	D B Wilson	Boswell Energy Center	Colstrip 3, 4
Big Bend	General James M Gavin	Labadie	Clover Power Project	
Coronado	Gibson	Labadie	Ghent	
Coronado	Martin Lake 2	Labadie	Gilberton Power/John B Rich	
Crystal River	Milton R Young	Labadie	H L Spurlock	
Crystal River	Mt Storm	Martin Lake 1	Iatan	
Jeffrey Energy Center	Mt Storm		Marion	
Laramie River Station			Mt Carmel Cogen	
Martin Lake			St Nicholas Cogen Project	
San Miguel			Walter Scott Jr Energy Center	
Seminole			WPS Westwood Generation LLC	

Table A-2 Technology Assignment for 0.006 lbs/MBtu PM Rate: Industry Study

FF O&M Enhancement	FF Retrofit	FF Retrofit
Antelope Valley	Alcoa/Warrick	Laramie River Station
Bonanza	Belews Creek	Leland Olds 1, 2
Boswell Energy Center Clay Boswell	Big Bend	Martin Lake 1-3
Clover Power Project	Cardinal	Merrimack
Comanche	Colstrip 3, 4	Milton R Young
Ghent	Coronado 1, 2	Monroe 1, 2
Gilberton Power/John B Rich	Crystal River 4, 5	Mt Storm 1, 2
H L Spurlock	D B Wilson	Naughton
Huntington	East Bend	Nebraska City
Iatan	General James M Gavin	R D Green
Louisa	Gibson 1, 3	R S Nelson
Marion	Gibson	Sam Seymour Fayette 1, 2
Mt Carmel Cogen	Independence	San Miguel
Oak Grove 1	IPL - AES Petersburg	Schiller
Sandy Creek Energy Station	James H Miller Jr	Seminole
Scrubgrass Generating 1, 2	Jeffrey Energy Center 1, 2, 3	Trimble County
St Nicholas Cogen Project	Jim Bridger 3, 4	Whelan Energy Center
Twin Oaks Power 1, 2	Labadie 1 -4	White Bluff 1, 2
Walter Scott Jr Energy Center		
Weston		
WPS Westwood Generation LLC		

Appendix B: Example Data Chart

Appendix A presents additional examples of units for which EPA's PM sampling and evaluation approach distorted results. These charts contain both mean and 99th percentile data. Data is presented for the following units, for which observations are offered as follows:

- TVA Gallatin Unit 1. EPA selected 0.0030 lbs/MBtu as the reference PM rate, using Q4 of 2019. Few of the 16 quarters that report lower PM emissions.

- TVA Gallatin Unit 2. EPA selected 0.0031 lbs/MBtu as the reference PM rate, also using Q4 of 2019. Few of the 16 quarters that report lower PM, similar to Unit 1.

- TVA Gallatin Unit 3. EPA selected 0.0016 lbs/MBtu as the reference PM rate, again using Q4 of 2019. Only one quarter (Q3 of 2019) reports lower PM rate.

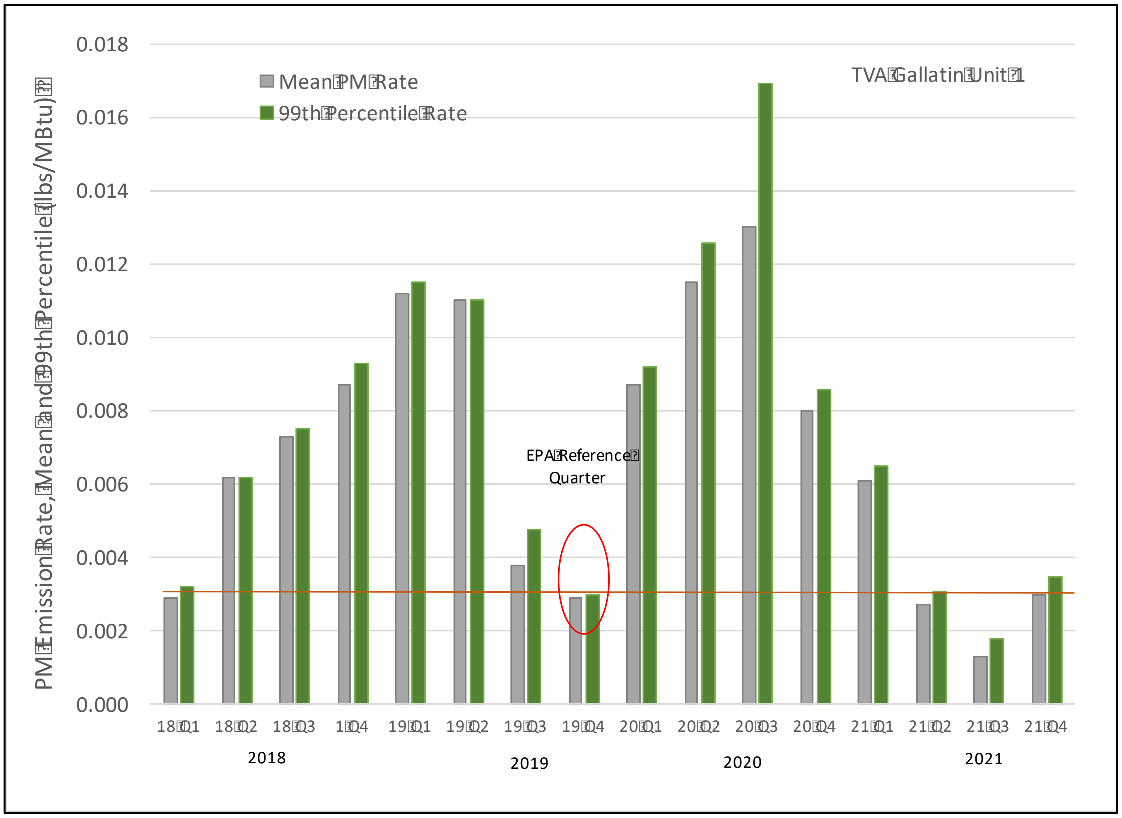
- TVA Gallatin Unit 4. EPA selected 0.0022 lbs/MBtu as the reference PM rate, using Q1 of 2021. Of the 14 quarters reporting data, two quarters report PM rates equal to this rate, while two are below this rate.

- LG&E/KU Ghent 1. EPA selected 0.005 lbs/MBtu as the reference PM rate, using Q2 of 2019. This PM rate represents that reported in previous quarters, but with one exception all subsequent quarters through 2021 report higher PM.

- LG&E/KU Mill Creek Unit 4. EPA selected 0.0035 lbs/MBtu as the reference PM rate, using Q4 of 2021. With the exception of the previous quarter, this value is the lowest of any reported since 2017 by a significant margin.

- Alabama Power Gaston Unit 5. EPA selected 0.005 lbs/MBtu as the reference PM rate, using Q1 of 2021. Data for this unit is displayed from Q1 2017 through Q4 2022. Of the 24 reporting quarters (1Q 2017 through 4QW 2022) only 6 quarters have lower PM rates.

- Alabama Power Miller Unit 1. EPA selected 0.004 lbs/MBtu as the reference PM rate, using Q3 of 2017. Data for this unit is displayed from Q1 2017 through Q4 2022. The designated rate represents a significant reduction from approximately half of the reporting quarters since Q1 2020.


0.018
0.016
0.014
0.012
0.010
0.008
0.006
0.004
0.002
0.000
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
Mean PM Rate
99th Percentile Rate
TVA Gallatin Unit 1
EPA Reference Quarter
18 Q1
18 Q2
18 Q3
1 Q4
19 Q1
19 Q2
19 Q3
19 Q4
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20 Q2
20 Q3
20 Q4
21 Q1
21 Q2
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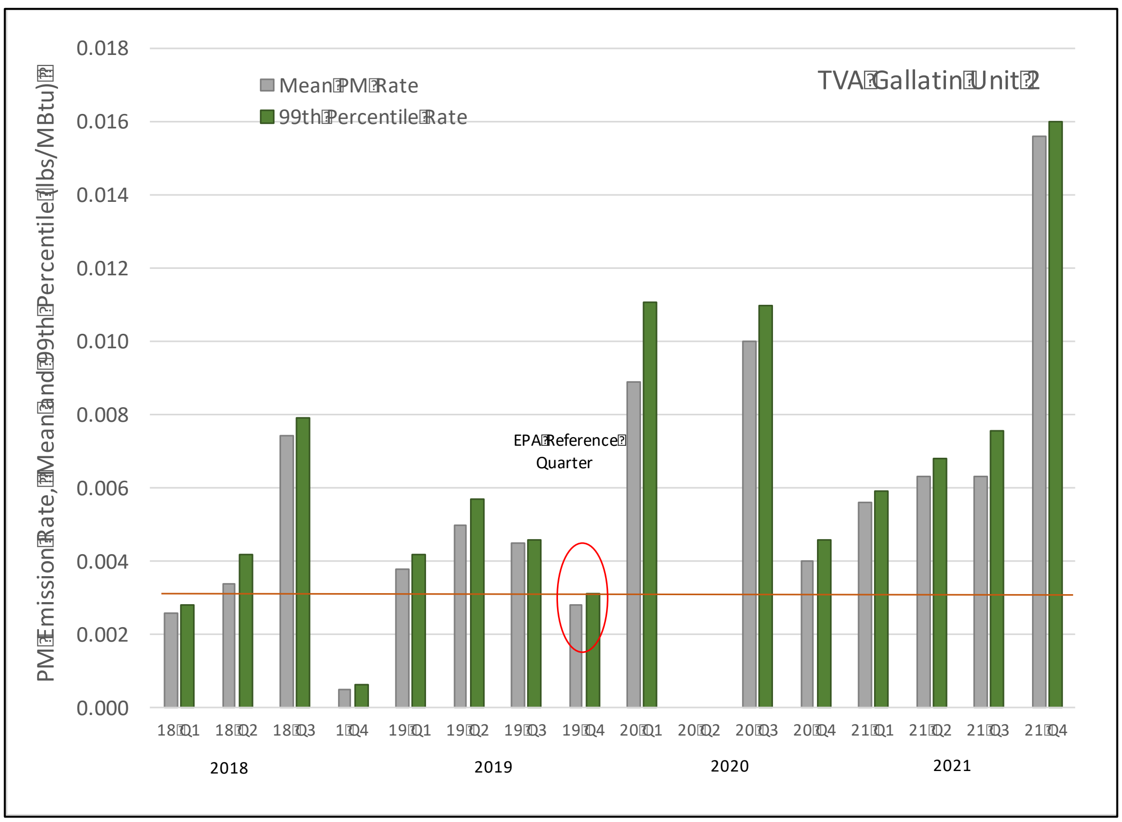
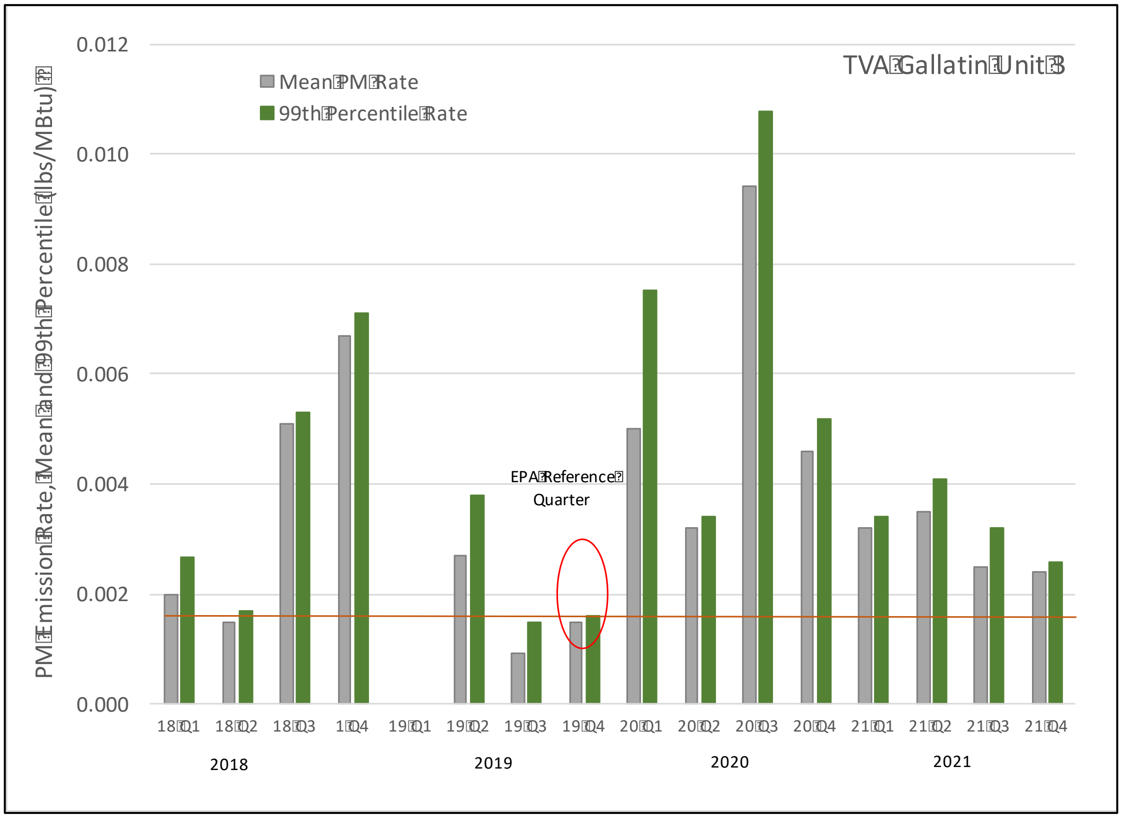
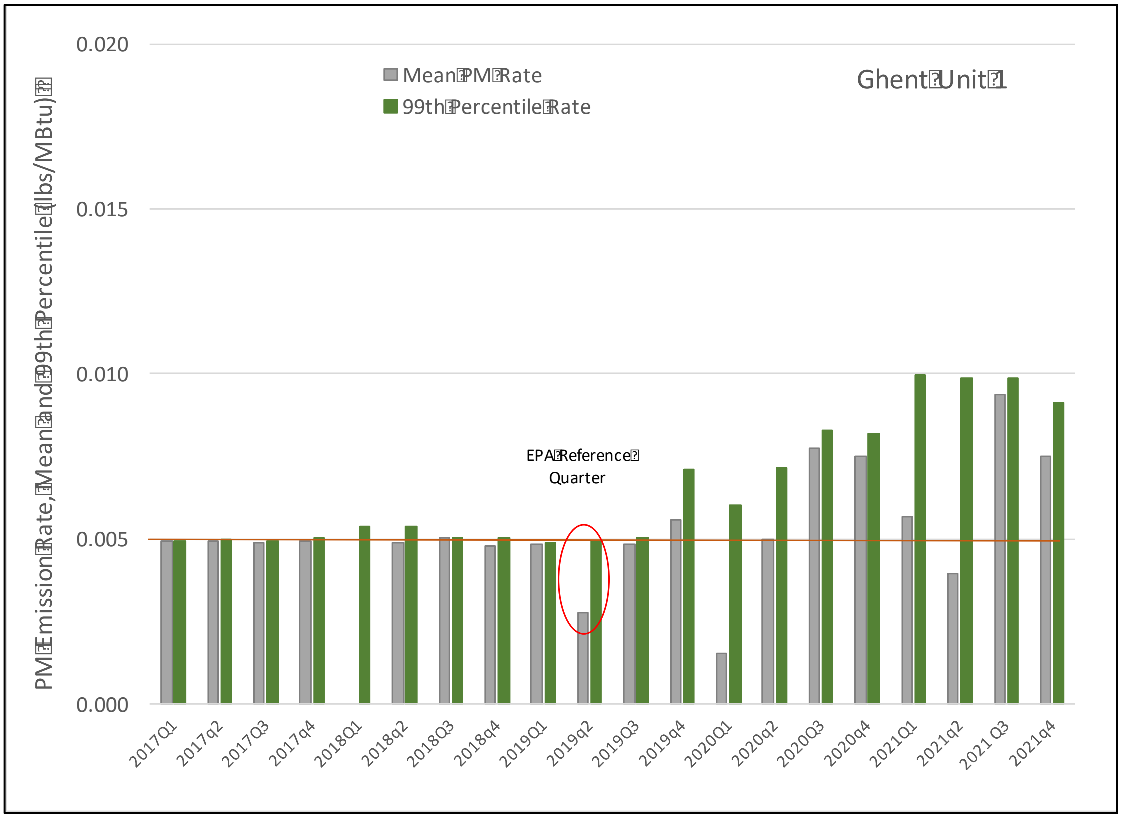
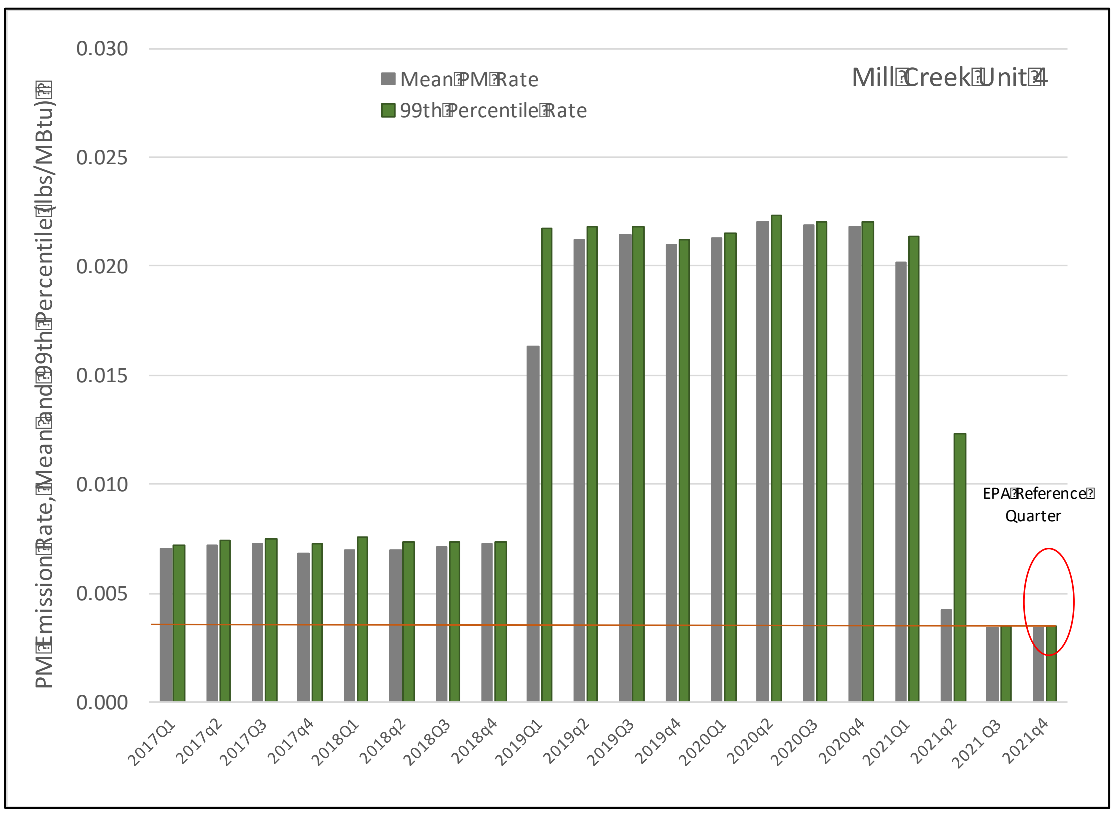
21 Q4
2018
2019
2020
2021

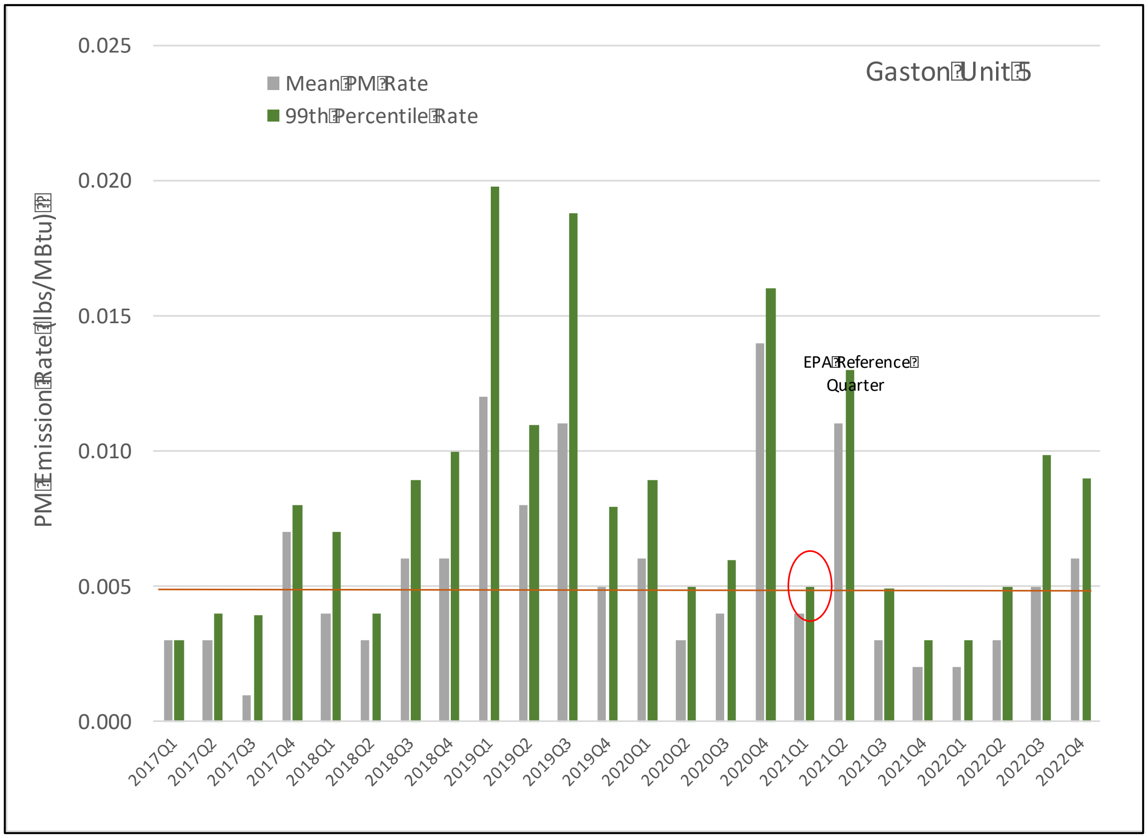

0.018
0.016
0.014
0.012
0.010
0.008
0.006
0.004
0.002
0.000
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
Mean PM Rate
99th Percentile Rate
TVA Gallatin Unit 2
EPA Reference Quarter
18 Q1
18 Q2
18 Q3
1 Q4
19 Q1
19 Q2
19 Q3
19 Q4
20 Q1
20 Q2
20 Q3
20 Q4
21 Q1
21 Q2
21 Q3
21 Q4
2018
2019
2020
2021

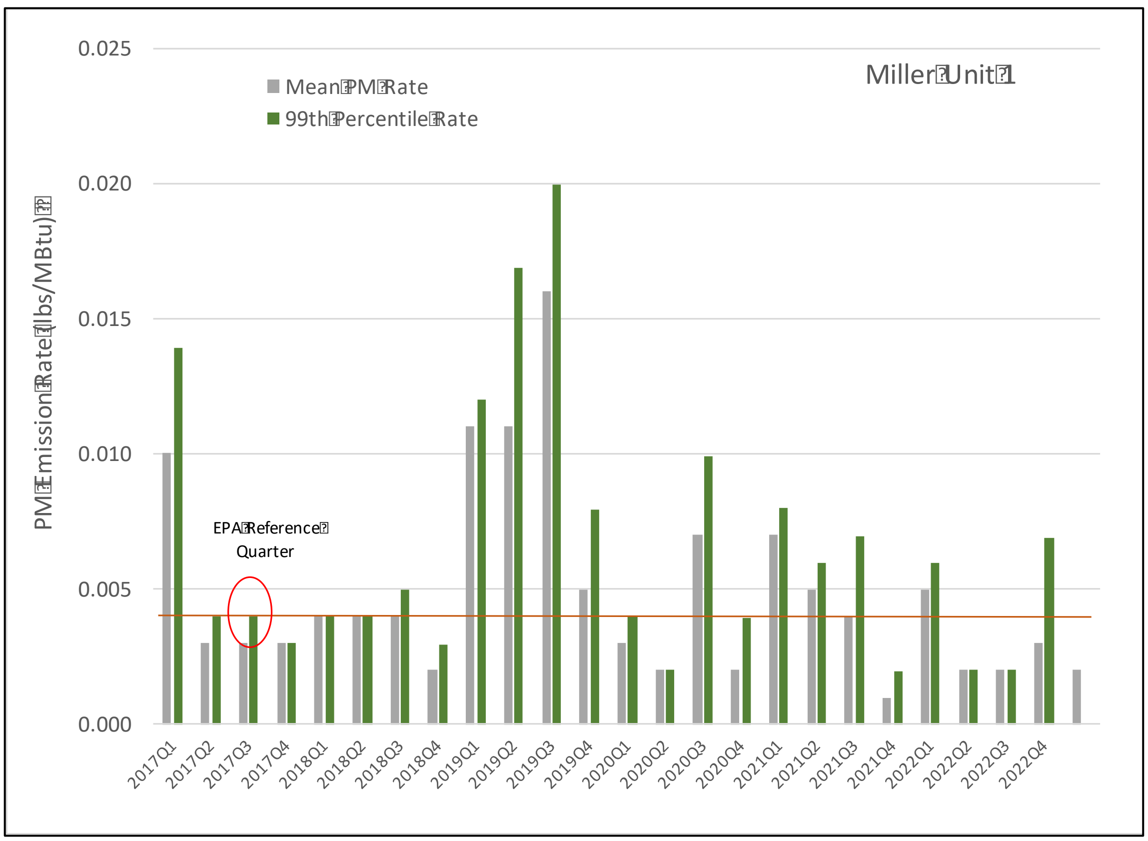

TVA Gallatin Unit 3
Mean PM Rate
99th Percentile Rate
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.012
0.010
0.008
0.006
0.004
0.002
0.000
EPA Reference Quarter
18 Q1
18 Q2
18 Q3
1 Q4
19 Q1
19 Q2
19 Q3
19 Q4
20 Q1
20 Q2
20 Q3
20 Q4
21 Q1
21 Q2
21 Q3
21 Q4
2018
2019
2020
2021

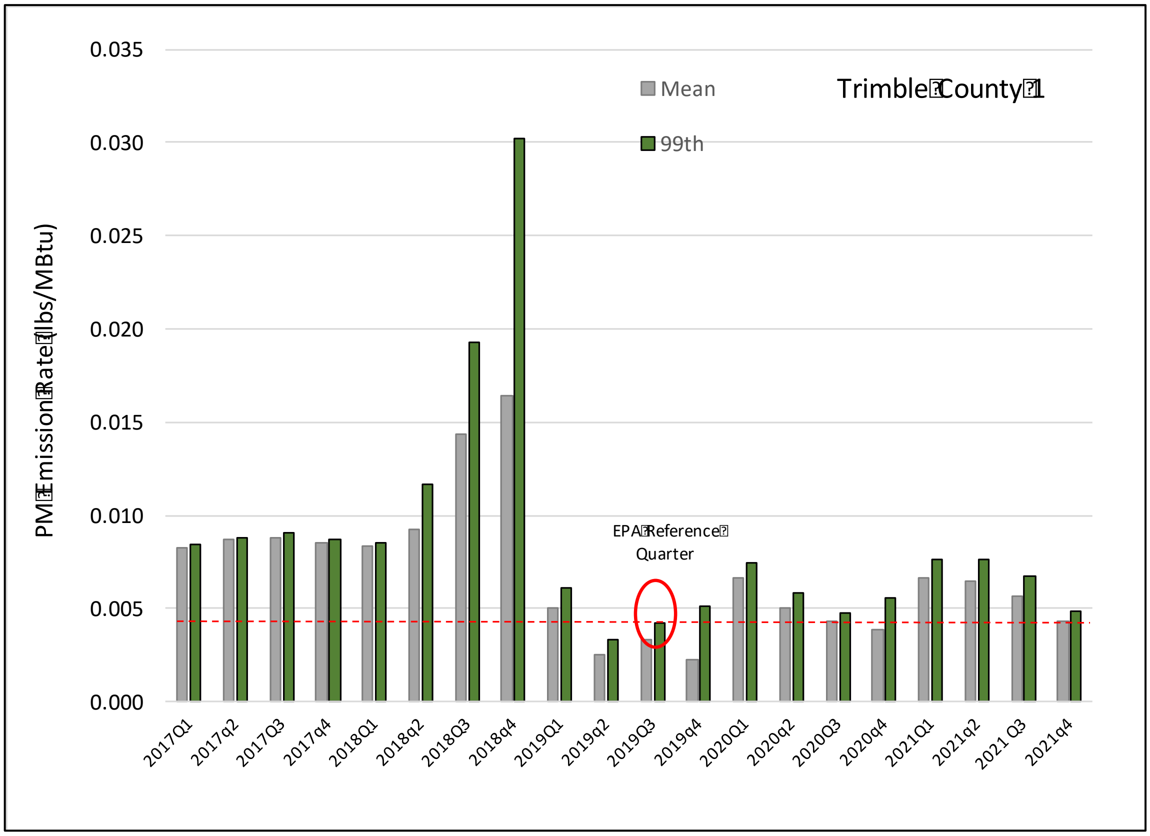

TVA Gallatin Unit 3
Mean PM Rate
99th Percentile Rate
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.012
0.010
0.008
0.006
0.004
0.002
0.000
EPA Reference Quarter
18 Q1
18 Q2
18 Q3
1 Q4
19 Q1
19 Q2
19 Q3
19 Q4
20 Q1
20 Q2
20 Q3
20 Q4
21 Q1
21 Q2
21 Q3
21 Q4
2018
2019
2020
2021


Ghent Unit 1
Mean PM Rate
99th Percentile Rate
EPA Reference Quarter
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.020
0.015
0.010
0.005
0.000
2017Q1
2017q2
2017Q3
2017q4
2018Q1
2018q2
2018Q3
2018q4
2019Q1
2019q2
2019Q3
2019q4
2020Q1
2020q2
2020Q3
2020q4
2021Q1
2021q2
2021 Q3
2021q4


Mill Creek Unit 4
Mean PM Rate
99th Percentile Rate
EPA Reference Quarter
PM Emission Rate, Mean and 99th Percentile (lbs/MBtu)
0.030
0.025
0.020
0.015
0.010
0.005
0.000
2017Q1
2017q2
2017Q3
2017q4
2018Q1
2018q2
2018Q3
2018q4
2019Q1
2019q2
2019Q3
2019q4
2020Q1
2020q2
2020Q3
2020q4
2021Q1
2021q2
2021 Q3
2021q4


Gaston Unit 5
Mean PM Rate
99th Percentile Rate
PM Emission Rate (lbs/MBtu)
0.025
0.020
0.015
0.010
0.005
0.000
EPA Reference Quarter
2017Q1
2017Q2
2017Q3
2017Q4
2018Q1
2018Q2
2018Q3
2018Q4
2019Q1
2019Q2
2019Q3
2019Q4
2020Q1
2020Q2
2020Q3
2020Q4
2021Q1
2021Q2
2021Q3
2021Q4
2022Q1
2022Q2
2022Q3
2022Q4


Miller Unit 1
Mean PM Rate
99th Percentile Rate
PM Emission Rate (lbs/MBtu)
0.025
0.020
0.015
0.010
0.005
0.000
EPA Reference Quarter
2017Q1
2017Q2
2017Q3
2017Q4
2018Q1
2018Q2
2018Q3
2018Q4
2019Q1
2019Q2
2019Q3
2019Q4
2020Q1
2020Q2
2020Q3
2020Q4
2021Q1
2021Q2
2021Q3
2021Q4
2022Q1
2022Q2
2022Q3
2022Q4


0.035
0.030
0.025
0.020
0.015
0.010
0.005
0.000
PM Emission Rate (lbs/MBtu)
Mean
99th
Trimble County 1
EPA Reference
Quarter
2017Q1
2017q2
2017Q3
2017q4
2018Q1
2018q2
2018Q3
2018q4
2019Q1
2019q2
2019Q3
2019q4
2020Q1
2020q2
2020Q3
2020q4
2021Q1
2021q2
2021 Q3
2021q4