MEMORANDUM

FROM:	Sarah Benish, Nick Hutson, Erich Eschmann U.S. EPA/OAR
TO:	Docket ID. No: EPA-HQ-OAR-2018-0794
DATE:	January 2023
SUBJECT:	2023 Technology Review for the Coal- and Oil-Fired EGU Source Category

This memorandum documents detailed data and analysis, including costs and filterable PM and mercury emissions impacts, as part of the technology review the U.S. Environmental Protection Agency (EPA) conducted in accordance with section 112(d)(6) of the Clean Air Act (CAA) to identify developments in practices, processes, and control technologies applicable to sources subject to the National Emissions Standards for Hazardous Air Pollutants (NESHAP) for coal- and oil-fired electric utility steam generating units (EGUs) (40 CFR 63, subpart UUUUU). The analysis focused on developments that have occurred since the 2020 technology review (see EPA-HQ-OAR-2018-0794-0015). This memorandum is organized as follows:

1. Background
2. Filterable Particulate Matter (fPM) Emission Limit
3. Mercury Limit for Lignite-Fired EGUs
4. Review of Acid Gas Emission Limits

1. Background

Sections 112(d)(2) and (3) of the CAA direct the EPA to develop maximum available control technology (MACT) standards to control hazardous air pollutants (HAP) emissions from major sources. For coal- and oil-fired EGUs, the MACT standards for major sources were promulgated on February 16, 2012, and are codified at 40 CFR part 63, subpart UUUUU (commonly referred to as Mercury and Air Toxics Standards (MATS)).

Section 112 of the CAA establishes a two-stage regulatory process to develop standards for emissions of HAP. Under CAA section 112(f)(2), the EPA assesses the residual risk for a source category to protect public health with “an ample margin of safety” or to prevent adverse environmental effects considering energy, costs, and other relevant factors within 8 years of promulgation of standards. CAA section 112(d)(6) requires EPA to review technology-based standards and to revise them “as necessary (taking into account developments in practices, processes, and control technologies)” no less frequently than every 8 years. These two reviews are commonly combined into a single rulemaking and referred to as the “risk and technology review” or RTR.

The EPA did not promulgate any revisions to the MATS rule based on its findings in the 2020 RTR, concluding that the residual risk of HAP remains low and no developments in practices, processes, or control technologies support altering the standards. The 2020 Technology Review concluded that existing air pollution control technologies that were in use were well-established and provided the capture efficiencies necessary for compliance with the MATS emission limits. However, in the 2020 Technology Review, the EPA did not consider developments in the cost and effectiveness of these proven technologies and did not evaluate the current performance of emission reduction control equipment and strategies at existing MATS-affected EGUs, to determine whether revising the standards were warranted.

Pursuant to Executive Order 13990 “Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis” (86 FR 7037; January 25, 2021), the EPA initiated review of the 2020 RTR. In the same action as the proposed rulemaking reaffirming it remains appropriate and necessary to regulate HAP, EPA solicited information on the cost and performance of new or improved technologies that control HAP emissions, improved methods of operation, and risk-related information to further inform the Agency’s assessment of the MATS RTR. Generally, the commenters were unaware of new technology, but indicated the current technology is more widely used, more effective, and cheaper than at the time of adoption of MATS (EPA-HQ-OAR-2018-0794-4962, EPA-HQ-OAR-2018-0794-5121, EPA-HQ-OAR-2018-0794-4942). Specific data or information regarding the technology review used to support this proposed action are discussed within.

2. Filterable Particulate Matter (fPM) Emission Limit

a) Baseline fPM Rates

The EPA evaluated quarterly fPM compliance data for coal-fired EGUs from 2017 to 2021 for units in the contiguous United States based on data availability. EGUs not evaluated in this analysis, due to missing WebFIRE data reports, use of PM CPMS, report in lb/MWh, or coding errors, are listed in Appendix A. The EPA plans to incorporate data for the EGUs listed in Appendix A, if possible, when issuing the final MATS Review of the RTR rule.

Rate estimates of fPM were based on recent data submitted via the EPA’s Compliance and Emissions Data Reporting Interface (CEDRI) by facilities with affected EGUs. 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). 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. We removed units from this analysis that have shut down or will shut down or no longer burn coal/oil by December 31, 2028. The EPA evaluated fPM rates for a total of 275 individual EGUs. The analysis includes EGUs planning to convert to natural gas by the proposed compliance date and thus would not be subject to the proposed rule (all of these EGUs already meet a 6.0E-03 lb/MMBtu potential standard and therefore have no associated upgrade costs or emission reductions assumed in this analysis). Only one facility outside the continental United States is expected to be subject to MATS by the proposed compliance period (up to three years after the effective date of the rule amendments).

Since operation of an EGU can vary year to year in response to weather, fuel prices, and energy demand, all available quarterly fPM data were evaluated independently for each EGU. Summary statistics (median, max, 99th, 95th, 90th, 85th, 80th, and 75th percentiles) for each quarter were compiled to characterize emissions variability within the quarter and are discussed below. Linear interpolation was used when the desired percentile fell between two points. Because in some cases multiple EGUs are routed to a single stack or a single EGU is routed to two stacks, the number of stacks is not the same as the number of EGUs. For units that demonstrate compliance by conducting quarterly stack testing, we calculated the percentiles for each quarter using the available (typically three) stack test runs. Similarly, for units with PM CEMS, the percentiles are calculated using quarterly (typically 90 days) 30-day running average PM rates.

We assessed summary statistics of the lowest quarter's fPM rate to evaluate the most representative metric to describe baseline fPM emissions. We evaluated the lowest quarter's maximum, 99th, 90th, 85th, 80th, 75th, and 50th percentiles fPM rates for each facility, presented in Appendix B. Two EGUs (7213_B_1 and 4271_B_B1) report valid quarterly 30-day rolling average fPM rates of 0.000 lb/MMBtu, which we assume is greater than 0.0 but less than 5.0E-03 lb/MMBtu due to rounding in the report. The average difference between the 99th and 50th percentiles for all EGUs is 9.85E-04 lb/MMBtu (median=6.22E-04 lb/MMBtu), which demonstrates that individual stack tests or the 30-day average CEMS data is relatively consistent within each quarter. The largest difference between the 99th and 50th percentiles of 1.42E-02 lb/MMBtu is for Harrington unit 62B (6193_B_062B). Harrington unit 62B uses quarterly stack testing and emissions averaging with a co-located EGU to demonstrate compliance with the 3.0E-02 lb/MMBtu standard.

The distribution of fPM rates for all facilities is displayed in

FIGURE 1—DISTRIBUTION OF FPM RATES (LB/MMBTU) FOR ALL AFFECTED EGUS BASED ON THE LOWEST QUARTER'S 99TH, 90TH, 85TH, 80TH, 75TH, AND 50TH PERCENTILES

NOTE: THE WHISKERS OF EACH BOX EXTEND FROM THE 5TH TO 95TH PERCENTILES AND THE BOX DENOTES THE 25TH AND 75TH PERCENTILES. THE CENTRAL HORIZONTAL LINE INDICATES THE MEDIAN, THE RED DIAMOND SHOWS THE MEAN, AND THE GREEN X DISPLAYS THE MAXIMUM FPM RATE1, illustrating the choice of percentile (*i.e.*, 99th vs. 50th percentile) changes the baseline fPM rates very little. Since the variability of the lowest quarter's 99th, 90th, 85th, 80th, 75th, and 50th percentiles is very similar, there is little impact on the amount of emission reductions and total annualized costs when looking at the fleet on whole.

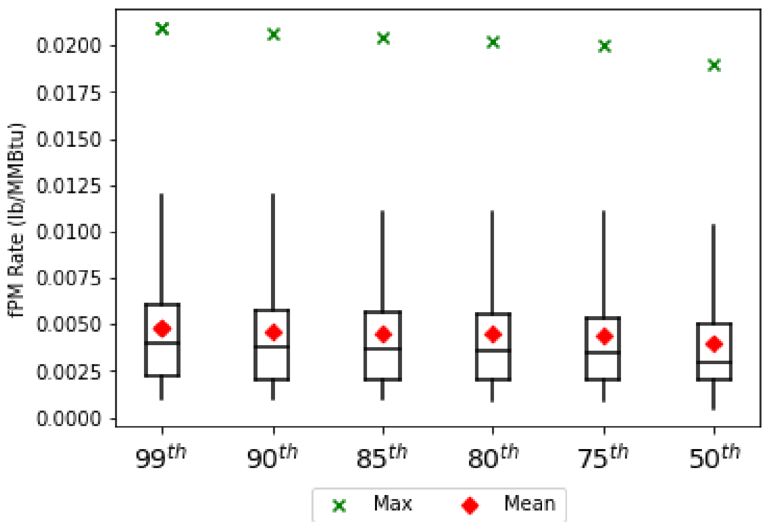

FIGURE 1—DISTRIBUTION OF FPM RATES (LB/MMBTU) FOR ALL AFFECTED EGUS BASED ON THE LOWEST QUARTER'S 99TH, 90TH, 85TH, 80TH, 75TH, AND 50TH PERCENTILES

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The 99th percentile of the lowest quarter was chosen to describe the baseline fPM rate for each EGU. Appendix C summarizes the baseline fPM rates and facility assumptions used in this analysis. We chose this baseline since units demonstrated they could meet this value 99 percent of the time during that quarter with their current control configuration. This approach may conservatively overestimate emissions. 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. Accordingly, the results identify the facilities requiring upgrades in PM controls to meet a lower limit. FIGURE 2—FPM RATE DISTRIBUTION USING THE 99TH PERCENTILE OF THE LOWEST QUARTER AS THE BASELINE FOR AFFECTED COAL-FIRED EGUS IN THE CONINENTAL UNITED STATES2 illustrates the baseline fPM rates for all affected units compared to the three assessed standards of 1.5E-02, 1.0E-02, 6.0E-03 lb/MMBtu. All affected units meet the current standard of 3.0E-2 lb/MMBtu, 96 percent of the capacity attains 1.5E-02 lb/MMBtu, 91 percent of the capacity achieves 1.0E-02 lb/MMBtu, and 72 percent of the capacity is below 6.0E-03 lb/MMBtu. A recent report[1] and a study received in

[1] "Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants" Andover Technology Partners, available at Docket No. EPA-HQ-OAR-2018-0794-4583 and *https://www.andovertechnology.com/wp-content/uploads/2021/08/PM-and-Hg-Controls_CAELP_20210819.pdf.*

Docket ID No. EPA-HQ-OAR-2018-0794-5121 have similarly concluded that lowering the PM emission rate would be possible without a large impact on the coal- and oil-fired fleet.

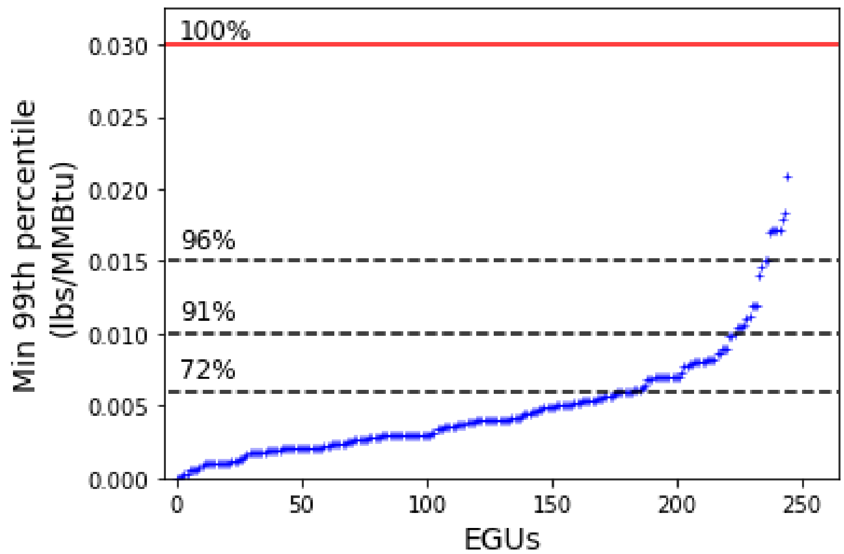

FIGURE 2—FPM RATE DISTRIBUTION USING THE 99TH PERCENTILE OF THE LOWEST QUARTER AS THE BASELINE FOR AFFECTED COAL-FIRED EGUS IN THE CONINENTAL UNITED STATES

b) Assessment of Facility Characteristics on fPM Rates

In this section, we evaluate the baseline fPM rate (*i.e.*, the lowest quarter's 99th percentile for each unit) summary statistics (mean, 5th percentile, median, and 95th percentile) based on facility characteristics reported in NEEDS.

i. Fuel type

Table 1 summarizes baseline fPM rate summary statistics (mean, 5th percentile, median, and 95th percentile) of EGUs based on their fuel type. For the majority of units burning either bituminous or subbituminous coal only we find the mean, 5th percentile, and median baseline fPM rates fall well below the most stringent standard considered of 6.0E-03 lb/MMBtu. Subbituminous coal has a larger 95th percentile of baseline fPM rates, 1.6E-02 lb/MMBtu, compared to bituminous coal of 1.1E-02 lb/MMBtu. However, waste coal is associated with the largest 95th percentile of the baseline fPM rates, 1.7E-02 lb/MMBtu, but has comparable mean, 5th percentile, and median baseline fPM rates as the other fuel types.

TABLE 1—BASELINE FPM RATES (LB/MMBTU) BASED ON DIFFERENT FUEL TYPES

Fuel Type	**Number**	**Baseline fPM Rate (lb/MMBtu)**			
		Mean	**5th percentile**	**Median**	**95th percentile**
Bituminous	73	4.70E-03	1.00E-03	4.00E-03	1.06E-02

Fuel Type	Number	Baseline fPM Rate (lb/MMBtu)			
		Mean	5th percentile	Median	95th percentile
Bituminous, Natural Gas	5	4.60E-03	1.80E-03	3.80E-03	8.50E-03
Bituminous, Petroleum Coke	2	1.60E-03	1.20E-03	1.60E-03	2.00E-03
Bituminous, Subbituminous	42	3.80E-03	1.60E-03	3.30E-03	6.90E-03
Bituminous, Subbituminous, Petroleum Coke	3	2.70E-03	1.20E-03	3.00E-03	3.90E-03
Bituminous, Waste Coal	6	7.40E-03	3.00E-03	7.00E-03	1.50E-03
Lignite	13	4.90E-03	1.50E-03	3.80E-03	9.00E-03
Lignite, Subbituminous	9	7.30E-03	2.50E-03	7.00E-03	1.32E-02
Subbituminous	106	4.60E-03	6.00E-03	3.70E-03	1.55E-02
Subbituminous, Petroleum Coke	1	7.90E-03			
Waste Coal	15	8.40E-03	3.20E-03	6.00E-03	1.65E-02

ii. Capacity

Baseline fPM rate summary statistics (mean, 5th percentile, median, and 95th percentile) for affected facilities grouped by capacity bins (MW) are shown in Table 2. The median and mean baseline fPM rates across the different capacity bins are similar, on the order of 3.0E-03 to 5.0E-03 lb/MMBtu. Additionally, the capacity bins have similar 5th percentile and 95th percentile baseline fPM rates.

TABLE 2—SUMMARY STATISTICS OF BASELINE FPM RATES (LB/MMBTU) ACROSS DIFFERENT CAPACITY BINS (MW) FOR AFFECTED UNITS

Capacity Bin (MW)	Number of EGUs	Baseline fPM Rate (lb/MMBtu)			
		Mean	5th percentile	Median	95th percentile
0-200	45	5.20E-03	9.00E-04	3.60E-03	1.51E-02
200-400	44	3.90E-03	1.10E-03	3.00E-03	8.60E-03
400-600	92	4.90E-03	6.00E-04	3.90E-03	1.51E-02
600-800	62	5.00E-03	1.00E-03	4.00E-03	1.16E-02
800-1000	21	5.20E-03	2.00E-03	5.20E-03	9.20E-03
1000+	11	5.20E-03	1.90E-03	3.90E-03	1.06E-02

iii. Pollution Control Equipment

Table 3 summarizes the distribution (mean, 5th percentile, median, and 95th percentile) of baseline fPM rates based on the primary PM control device and use of dry sorbent injection

(DSI). Units with wet scrubbers (WS) only are associated with the largest baseline fPM rate distributions, but we find all primary PM control devices are associated with baseline fPM rates below the current standard of 3.0E-02 lb/MMBtu. Excluding the WS, all primary PM control devices indicate a median baseline fPM rate below the most stringent standard considered, 6.0E-03 lb/MMBtu. While the majority of units utilize a fabric filter (FF) or electrostatic precipitator (ESP) only to control fPM, we find units with multiple control devices have smaller 95th percentile baseline fPM rates. For instance, the 95th percentile of FF or ESP only is 1.2E-02 and 1.4E-02 lb/MMBtu, respectively, whereas some combinations of control devices (*i.e.*, FF+ additional non-ESP control, ESP+ FF, and ESP+cyclone) indicate a 95th percentile between 6.0E-03 to 7.8E-03 lb/MMBtu. We find no major differences in the baseline fPM rate distribution between units that use DSI and that do not utilize DSI.

TABLE 3—BASELINE FPM RATES (LB/MMBTU) BASED ON THE PRIMARY PM CONTROL DEVICE AND USE OF DRY SORBENT INJECTION (DSI)

	Technology	**Number of EGUs**	**Baseline fPM Rate (lb/MMBtu)**			
			Mean	**5th percentile**	**Median**	**95th percentile**
Primary PM Control Device	FF only	97	4.20E-03	6.00E-04	3.00E-03	1.17E-02
	FF + Additional non-ESP Control	21	3.60E-03	7.00E-04	3.00E-03	7.00E-03
	ESP only	109	5.60E-03	1.80E-03	4.70E-03	1.40E-02
	ESP + FF	32	3.90E-03	8.00E-04	4.00E-03	7.80E-03
	ESP + Other Control Device (not FF)	12	4.80E-03	2.00E-03	4.00E-03	1.15E-02
	ESP + Cyclone	2	5.50E-03	5.00E-03	5.50E-03	6.00E-03
	Wet scrubber	2	1.95E-02	1.82E-02	1.95E-02	2.08E-02
Use of DSI?	Yes	44	5.80E-03	1.20E-03	4.90E-03	1.15E-02
	No	231	4.60E-03	1.00E-03	3.80E-03	1.12E-02

c) Existing PM Control Technologies

40 CFR part 63, subpart UUUUU regulates the fPM emissions as a surrogate for non-Hg HAP metals. To comply with the CAA section 112(d)(6) requirement, the EPA conducted a technology review in 2020, “National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units–Reconsideration of Supplemental Finding and Residual Risk and Technology Review” (85 FR 31286; May 22, 2020) (2020 Final Action). The results of the 2020 technology review are in a memorandum entitled “Technology Review for the Coal- and Oil-Fired EGU Source Category, July 2018” (Docket ID No. EPA-HQ-OAR-2018-0794-0015).

At the time of promulgation of MATS, the primary control devices installed at EGUs for control of PM included ESPs and FFs. The EPA found that ESPs are the most common PM control devices at coal- and oil-fired EGUs. An ESP removes particles from a gas stream using electrical energy to charge the particles and is capable of greater than 99 percent collection efficiencies. FFs, also referred to as a baghouses, remove particles from the gas stream by depositing the particles on fabric material and generally are capable of collection efficiencies of more than 99.9 percent.

The 2020 technology review did not identify developments in practices, processes, or control technologies for non-Hg HAP metals. However, in the EPA's review of the appropriate and necessary finding that was proposed on February 9, 2022 (87 FR 7624) (2022 Proposal), the EPA also solicited information to further inform the Agency's review of the MATS RTR. The EPA received comments during the 2022 Proposal that the industry has identified low-cost methods to achieve lower PM emissions than the current standard of 3.0E-02 pounds per million British thermal units (lb/MMBtu) since promulgation of MATS in 2012, including improvements to monitoring and control technologies. In addition, the Andover Technology Partners report[2] attributes significant improvements in PM emission rates since 2011 to wider deployment today of technologies that may have existed but not widely used in 2011, improved practices due to more regular and robust monitoring, and improvements to monitoring and ESP/FF technology.

d) New Cost Assumptions for Additional fPM Reductions

This section summarizes the cost and emissions reductions assumptions used by EPA in this memo. These assumptions are based on technical reports developed by Sargent and Lundy (S&L) for EPA, as cited below in each section. The S&L cost assumptions used in this analysis will be discussed in further detail below for each PM control device.

i. Electrostatic precipitators (ESP)

EPA's assumptions for upgrades to existing ESPs are based on a report prepared by S&L for EPA titled: "PM Incremental Improvement Memo" (available in the docket). This study summarizes potential upgrades or modifications to existing particulate control devices that could be made to incrementally improve the reduction of fPM. The study discusses three ranges of upgrades to existing ESP devices, the potential costs and performance of which are summarized in in Table 4.

TABLE 4—COST ASSUMPTIONS FOR IMPROVING FILTERABLE PM CONTROL AT EXISTING ESP DEVICES

Option	**Minor Upgrades (Low Cost)**	**Typical Upgrades (Average Cost)**	**ESP Rebuild (High Cost)**
Estimated Cost	\$6-\$27 / kilowatt (kW)	\$45-\$65 / kW	\$75-\$100 / kW
Potential Performance Improvement (Not Guaranteed Performance)	5%-10% reduction in fPM emissions; not applicable to units with current emission rates ≤ 0.010 lb/MMBtu	10-20% reduction in fPM emissions; not applicable to units with current emission rates ≤ 0.010 lb/MMBtu	Performance limited to 99.9% fPM removal (clean conditions)

[2] *Ibid.*

ii. Baghouse/Fabric Filter

EPA's assumptions for upgrades to existing FF are based on a report prepared by S&L for EPA titled: "PM Incremental Improvement Memo" (available in the docket). This study summarizes potential FF improvement options including upgrading the bag type, which can result in lower fPM emissions. In this cost analysis, EPA calculates the incremental cost of replacing standard bags with fiberglass bags with polytetrafluoroethylene (PTFE) membrane coating based on the assumptions detailed in the memo. The cost is estimated at the unit level, and ranges from about $15,000 per year to $528,000 per year. This cost analysis assumes that these upgrades reduce filterable PM by up to 50 percent.

EPA's assumptions for the cost of new fabric filters are based on the report prepared by S&L for EPA titled: "Particulate Control Cost Development Methodology."[3] This report provides a methodology used for estimating the unit-level costs of constructing and operating new FF. The cost analysis in this memo assumes unit-level cost estimates representing the capital and operation costs associated with a new 6.0 air-to-cloth (A/C) pulse-jet FF (PJFF). This cost analysis assumes that a new FF reduces fPM by up to 90%.

iii. Other control technologies

While ESPs and FF are the primary control technologies used to control PM, some facilities can achieve fPM reductions using alternative equipment. For instance, two units at Colstrip utilize a venturi WS for fPM control. Since WS are less effective at reducing fPM, particularly smaller particles, we assume a minimal cost ($10/kW) for WS maintenance or minor upgrades for these EGUs to meet a potential 0.015 lb/MMBtu standard. To achieve a 1.0E-02 and 6.0E-03 lb/MMBtu standards, we assume a FF would be installed. Unit-specific FF cost estimates for each unit at this facility were estimated based on the report prepared by S&L for EPA titled: "Particulate Control Cost Development Methodology."[4]

e) Particulate matter and non-Hg HAP metal Reductions

In this memo, the EPA assumes that the amount of fPM and therefore non-Hg HAP metal reductions depend on the current PM control configuration as well as the potential fPM limit analyzed, as summarized in Table 5. Existing control assumptions are based on EPA's NEEDS database.[5]

For units with an existing ESP and no FF, we assume that the ESP upgrades summarized in Table 4 would be necessary to reduce fPM to either 1.5E-02 or 1.0E-02 lb/MMBtu. We assumed the maximum potential performance improvement associated with the upgrade options (*i.e.*, 10% reduction for minor upgrades and 20% reduction for typical upgrades). In order to reduce fPM to 6.0E-03 lb/MMBtu or below, the EPA assumes that a FF is required. For EGUs with an existing

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[3] "Particulate Control Cost Development Methodology" available in the docket and at *https://www.epa.gov/system/files/documents/2021-09/attachment_5-7_pm_control_cost_development_methodology.pdf.*

[4] *Ibid.*

[5] NEEDS v621 rev: 10-14-22, available at: *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6*

ESP and without an existing FF, we assume the baseline fPM rate will decrease by 90 percent, with a maximum reduction to 2.0E-03 lb/MMBtu.

For EGUs with an existing FF, the EPA assumes that FF bag upgrades will reduce fPM rates to 6.0E-03 lb/MMBtu for all three potential fPM standards.

For the one facility with existing venturi-type WS (and without an existing ESP or FF), EPA assumes that ESP upgrades will reduce fPM emission to 1.5E-02 lb/MMBtu. To achieve the lower potential fPM standards, EPA assumes that these EGUs would require FF installation, reducing baseline fPM rates by 90% subject to a floor of 2.0E-03 lb/MMBtu.

TABLE 5—SUMMARY OF TECHNOLOGY AND FPM RATE ASSUMPTIONS FOR DIFFERENT PM CONTROL DEVICES

	Potential fPM Standards (lb/MMBtu)					
PM Control Device	**1.5E-02**		**1.0E-02**		**6.0E-03**	
	Technology Assumption	**Assumed fPM Rate (lb/MMBtu)**	**Technology Assumption**	**Assumed fPM Rate (lb/MMBtu)**	**Technology Assumption**	**Assumed fPM Rate (lb/MMBtu)**
ESP only	ESP upgrade	1.5E-02	ESP upgrade	1.0E-02	New FF installation	90% reduction from baseline, up to 2.0E-03 lb/MMBtu
FF only or FF in combination with other PM controls	FF bag upgrade	6.0E-03	FF bag upgrade	6.0E-03	FF bag upgrade	6.0E-03
Wet Scrubber	WS maintenance/ ESP upgrade	1.5E-02	New FF installation	90% reduction from baseline, up to 2.0E-03	New FF installation	90% reduction from baseline, up to 2.0E-03

Filterable PM reductions (fPM_{red}) for each potential limit (L; 1.5E-02, 1.0E-02, 6.0E-03 lb/MMBtu) were estimated using the annual heat input following Equation 1:

$$fPM_{red}\left(\frac{tons}{yr}\right) = \left(L - PM\ rate\ \left(\frac{lb}{MMBtu}\right)\right) \times Heat\ Input\left(\frac{MMBtu}{yr}\right) \times \frac{2000\ tons}{lb} \qquad (1)$$

Emissions ratios were used to transform the fPM reductions at each EGU into $PM_{2.5}$ and individual non-Hg HAP metal reductions. The non-Hg HAP metals that affect human health assessed in this analysis included arsenic (As), beryllium (Be), cadmium (Cd), cobalt (Co), chromium (Cr), manganese (Mn), nickel (Ni), Lead (Pb), antimony (Sb), and selenium (Se). The emissions ratios, available in the docket, specific for each fuel type and PM control type for

EGUs still in operation, were derived from 2010 Information Collection Request (ICR) data, which is described in the 2018 memo, "Emission Factor Development for RTR Risk Modeling Dataset for Coal- and Oil-fired EGUs".[6]

Table 6 summarizes the total emission reductions obtained at affected units for fPM, $fPM_{2.5}$, and speciated non-Hg HAP metals for the three potential fPM limits. Since non-Hg HAP metals comprise ~0.8 percent of the fPM, there are comparatively more reductions of fPM and $fPM_{2.5}$. Unit-specific fPM emission reductions are provided in Appendix D.

TABLE 6—FPM, $FPM_{2.5}$, AND SPECIATED NON-HG HAP METAL REDUCTIONS (TONS/YEAR) ESTIMATED AS A RESULT OF THREE POTENTIAL FPM LIMITS OF 1.5E-02, 1.0E-02, AND 6.0E-03 LB/MMBTU

Emission Reductions (tons/year)	**Potential PM Standard (lb/MMBtu)**		
	1.5E-02	**1.0E-02**	**6.0E-03**
fPM	463	2074	6163
$fPM_{2.5}$	246	1083	3022
Total non-Hg metallic HAP	1.41	6.34	24.7
As	0.07	0.29	0.91
Be	0.01	0.02	0.06
Cd	0.01	0.04	0.11
Co	0.02	0.08	0.27
Cr	0.31	1.43	6.14
Mn	0.45	1.54	5.55
Ni	0.17	0.79	2.82
Pb	0.13	0.51	1.04
Sb	0.02	0.10	0.27
Se	0.22	1.54	7.56

f) Annual fPM Costs and Cost Effectiveness

Annual control cost and emissions reduction assumptions are assigned to each unit based on the information presented above in sections 2.1, 2.2, 2.3, and 2.4. Capital costs are annualized over a lesser of a 15-year time horizon or the planned retirement date of each EGU. For the 1.5E-02 and 1.0E-02 lb/MMBtu standards, costs are presented as a range to reflect the range of ESP upgrade costs developed by S&L (Table 4). Table 7 summarizes the annual costs for the affected units as well as the fPM and non-Hg HAP metal cost effectiveness. Unit-specific costs to achieve these three potential limits are provided in Appendix D.

[6] "Emission Factor Development for RTR Risk Modeling Dataset for Coal- and Oil-fired EGUs" available at https://www.regulations.gov/document/EPA-HQ-OAR-2018-0794-0010.

TABLE 7—TOTAL ANNUALIZED COSTS ($M) AND COST EFFECTIVENESS OF FPM ($K/TON) AND NON-HG HAP METALS ($K/LB) FOR THREE POTENTIAL FPM LIMITS OF 1.5E-02, 1.0E-02, AND 6.0E-03 LB/MMBTU

		Potential fPM Standard (lb/MMBtu)		
		1.5E-02	**1.0E-02**	**6.0E-03**
Annualized Costs ($M)		13.9-19.3	77.3-93.2	633
Cost Effectiveness based on Actual Emissions	fPM ($k/ton)	30.0-41.6	37.3-44.9	103
	fPM2.5 ($k/ton)	56.5-78.4	71.3-86.0	209
	Total non-Hg metallic HAP ($k/ton)	9,860-13,700	12,200-14,700	25,600
	As ($k/ton)	195,000-271,000	269.000-324.000	698,000
	Be ($k/ton)	2,490,000-3,460,000	4,180,000	11,400,000
	Cd ($k/ton)	1,140,000-1,580,000	1,720,000-2,080,000	5,990,000
	Co ($k/ton)	623,000-864,000	985,000-1,150,000	2,340,000
	Cr ($k/ton)	44,400-61,600	54,200-65,400	103,000
	Mn ($k/ton)	30,900-43,000	50,100-60,400	114,000
	Ni ($k/ton)	83,900-116,000	97,300-117,000	224,000
	Pb ($k/ton)	107,000-149,000	151,000-182,000	607,000
	Sb ($k/ton)	689,000-956,000	785,000-947,000	2,311,000
	Se ($k/ton)	62,900-87,200	50,200-60,400	83,600
Cost Effectiveness based on Allowable Emissions	Total non-Hg metallic HAP ($/ton)	35.4-49.1	197-238	1,610

Since the three potential standards impact only a small portion of the fleet, we also assess the cost-effectiveness of allowable emissions from the entire fleet. Allowable fPM emissions at the current standard of 3.0E-02 lb/MMBtu were calculated for the entire fleet using unit-specific annual heat input. From the fPM emissions, we estimate the total non-Hg HAP emissions using emissions ratios of non-Hg metal HAP/fPM discussed above. We use an average emission ratio (non-Hg HAP/fPM) of 4.10E-03 lb/lb for units with baseline fPM rates below 6.0E-03 lb/MMBtu. We estimate a total of 7.8E05 lb/year (392 tons/year) total non-Hg HAP emissions from EGUs included in this analysis. This cost-effectiveness approach using allowable emissions is not comparable to the standard methodology used in section 112 rulemakings, but does consider if the fleet were operating at levels allowed by the 2012 MACT rule.

3. Mercury Limit for Lignite-Fired EGUs

a) *Hg Emissions from Coal-fired EGUs*

The EPA estimated Hg emissions from coal-fired power plants in 2010 (pre-MATS) to be 29 tons.[7] In 2017, after full implementation of the MATS rule, the EPA estimated Hg emissions had been reduced to 4 tons, an 86 percent decrease.[8] This decline was not entirely due to an increased use of Hg controls as there were also significant changes in the power sector (*e.g.*, coal plant retirements, increase use of natural gas and renewable energy, *etc*.) in the same time period.

Hg emission reductions have continued to decline as more coal-fired EGUs have retired or reduced utilization. The EPA estimated that 2021 Hg emissions from coal-fired EGUs were 3 tons (a 90 percent decrease compared to pre-MATS levels).[9] However, units burning lignite coal (or permitted to burning lignite) accounted for a disproportionate amount of the total Hg emissions in 2021. As shown in Table 8 below, lignite-fired EGUs, located exclusively in North Dakota and Texas, were the top 18 highest Hg emitting EGUs. Overall, lignite-fired EGUs were responsible for almost 30 percent of all Hg emitted from coal-fired EGUs in 2021, while generating about 7 percent of total 2021 megawatt-hours. Lignite accounted for 8 percent of total U.S. coal production in 2021.

TABLE 8— TOP HG-EMITTING EGUS IN 2021

Rank	**EGU**	**2021 Hg Emissions (lb)**	**State**
1	Coal Creek 2	181.8	ND
2	Coal Creek 1	175.6	ND
3	Oak Grove 2	149.8	TX
4	Martin Lake 3	134.4	TX
5	Oak Grove 1	112.7	TX
6	Martin Lake 2	111.0	TX
7	Milton R Young B2	103.1	ND
8	Martin Lake 1	100.7	TX
9	Antelope Valley B2	89.8	ND
10	Coyote B1	79.9	ND
11	H W Pirkey Power Plant 1	71.1	TX
12	Antelope Valley B1	69.6	ND
13	San Miguel SM-1	64.6	TX
14	Sandy Creek Energy Station S01	53.5	TX
15	Limestone LIM2	52.5	TX

[7] Memorandum: Emissions Overview: Hazardous Air Pollutants in Support of the Final Mercury and Air Toxics Standard. EPA–454/R–11–014. November 2011; Docket ID No. EPA–HQ–OAR– 2009–0234–19914.

[8] 2017 Power Sector Programs Progress Report; available at *https://www.epa.gov/sites/default/files/2019-12/documents/2017_full_report.pdf* and in the rulemaking docket.

[9] 2021 Power Sector Programs Progress Report; available at *https://www3.epa.gov/airmarkets/progress/reports/pdfs/2021_report.pdf* and in the rulemaking docket.

16	Milton R Young B1	52.4	ND
17	Comanche 3	50.3	ND
18	Leland Olds 2	50.1	ND
19	James H Miller Jr 3	42.9	AL
20	Labadie 2	42.5	MO

In May 2021, pursuant to authority in section 114 of the CAA, 42 U.S.C. §7414(a), the EPA solicited information related to Hg emissions and Hg control technologies from certain lignite-fired EGUs to inform this CAA section 112(d)(6) technology review. The selected lignite-fired EGUs were asked to provide information on their control configuration for Hg and for other air pollutants (*e.g.*, criteria pollutants such as PM, NO_X, SO_2). Selected information on lignite-fired EGU control configurations that was obtained from the CAA section 114 information request is shown below in Table 9. Additional information on the location, size (capacity), firing configuration, and control configuration of lignite-fired EGUs (including those few that were not included in the CAA section 114 information request) is also included. The additional information was obtained from the EPA's NEEDS database.[10]

Most, but not all, of the EGUs utilized a combination of the use of a chemical additive and injection of a sorbent as their Hg control strategy. One facility in North Dakota (Antelope Valley) uses a liquid sorbent that is injected to the SO_2 scrubber (spray dryer absorber, SDA). Many of the EGUs used "refined coal." Refined coal is typically produced by mixing proprietary additives to feedstock coal to help capture emissions when the coal is burned. For example, these additives may promote the oxidation of Hg to Hg^{2+} compounds for capture in downstream control equipment (*e.g.*, FGD scrubbers, PM control devices). Several of the facilities noted that use of refined coal as a part of their Hg control strategy was discontinued at the end of 2021 when the refined coal production tax credit (created by the American Jobs Creation Act of 2004) expired. According to a U.S. Government Accountability Office audit report, refined coal producers claimed approximately $8.9 billion in tax credits between 2010 and 2020.

[10] National Electric Energy Data System (NEEDS) v621 rev: 10-14-22, available at: *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6*.

TABLE 9—CONTROL CONFIGURATIONS FOR LIGNITE-FIRED EGUS

Plant Name	**State**	**Capacity (MW)**	**Firing**	**Control Configuration**	**Hg Control Description**	**Hg Control**
Antelope Valley #1	ND	450	tangent	ACI + SDA + FF	Does not use activated carbon as its sorbent, instead **injects a liquid sorbent** to the scrubber. The facility stopped using refined coal in December 2021.	Nalco non-carbon, **non-halogenated liquid sorbent** added to dry scrubber; M-Sorb additive (bromide)
Antelope Valley #2	ND	450	tangent	ACI + SDA + FF		
Coal Creek #1	ND	574	tangent	ACI + ESPC + WFGD	Information not collected in the CAA 114 request	
Coal Creek #2	ND	573	tangent	ACI + ESPC + WFGD		
Coyote	ND	429	cyclone	ACI + SDA + FF	Information not collected in the CAA 114 request	
Leland Olds #1	ND	222	wall	SNCR + ACI + ESPC + WFGD	Activated carbon and oxidizer injections for Hg control	ME2C SEA SF10 Oxidizer and SB24 Activated Carbon
Leland Olds #2	ND	445	cyclone	SNCR + ACI + ESPC + WFGD		
Milton R Young #1	ND	237	cyclone	SNCR + ACI + ESPC + WFGD	Hg controlled by Powdered Activated Carbon Injection plus Oxidizing Agent/Halogen Injection System	DARCO Hg-H **non-halogenated** Powdered Activated Carbon + ADA M-Prove additive
Milton R Young #2	ND	447	cyclone	SNCR + ACI + ESPC + WFGD		
Spiritwood Station	ND	92	FBC	SNCR + ACI + SDA + FF	Hg emissions are controlled by **activated carbon injection system** and a continuous emissions monitoring system (CEMS). The activated carbon injection feed rate is adjusted to maintain emissions below the 4.0 lb/TBtu standard.	Activated Carbon sorbent (not specified)
Limestone #1	TX	831	tangent	SNCR + ACI + ESPC + WFGD	Information not collected in the CAA 114 request	
Limestone #2	TX	858	tangent	SNCR + ACI + ESPC + WFGD		

Major Oak #1	TX	152	FBC	Reagent Injection + SNCR + ACI + FF	Hg is controlled by the **introduction of activated carbon** into each boiler duct directly in front of the baghouse. A **halogen fuel additive is also applied** to the lignite before it enters the day silos.	Cabot DARCO Hg-H **non-Brominated AC** + ADA-ES M-Prove additive
Major Oak #2	TX	153	FBC	Reagent Injection + SNCR + ACI + FF		
Martin Lake #1	TX	800	tangent	ACI + ESPC + WFGD	**Brominated additive injected** into the furnace and **activated carbon injected** upstream of the air heater. In 2020 and 2021 **Refined Coal System** applied an aqueous bromine salt solution to the coal.	ME2C SEA process (**non-Brominated AC** + chemical additive)
Martin Lake #2	TX	805	tangent	ACI + ESPC + WFGD		
Martin Lake #3	TX	805	tangent	ACI + ESPC + WFGD		
Oak Grove #1	TX	855	tangent	SCR + ACI + FF + WFGD	**Brominated activated carbon injected** downstream of the air heater. From 2018 to 2021, the unit was equipped with a **Refined Coal System** for Hg control. This system applied an aqueous bromine salt solution to the coal downstream of the crusher. The refined coal system is no longer in service.	ADA-CS Br-AC
Oak Grove #2	TX	855	wall	SCR + ACI + FF + WFGD		

Red Hills #1	MS	220	FBC	Reagent Injection + ACI + FF	Hg is controlled by **injection of activated carbon** into each boiler duct directly in front of the baghouse. A **fuel additive is also applied to the lignite** before it enters the day silos. The application of fuel additives ended in December 2021.	ADA-CS non-Br AC + ADA-ES M45 liquid additive
Red Hills #2	MS	220	FBC	Reagent Injection + ACI + FF		
San Miguel	TX	391	wall	SNCR + ACI + ESPC + WFGD	Hg is captured using a sorbent enhanced additive (SEA) injected onto the lignite at the pulverizer feeders or directly into the furnace to promote the oxidation and capture of Hg. This is followed by an ACI system located in the boiler exit duct work upstream of the air heaters. The scrubber system also reduces Hg emissions.	ME2C SEA process (non-Br AC + powder-based chemical additive)

Note: ACI = activated carbon injection; SDA = spray dryer absorber (dry scrubber); FF = fabric filter; ESPC = cold side electrostatic precipitator; WFGD = wet flue gas desulfurization scrubber; SNCR = selective non-catalytic reduction (NOx control); reagent injection = sorbent injection into fluidized bed combustor

According to fuel use information supplied to EIA (on form 923), 13 of 22 EGUs that were designed to burn lignite utilized refined coal to some extent in 2021, as summarized in Table 10. EIA form 923 does not specify the type of coal that is "refined." For this technology review, the EPA has assumed that the facilities have utilized "refined lignite." However, several "lignite-fired EGUs" located in Texas reported very high use of subbituminous coal in 2021 (ranging from 76 percent up to > 99 percent).

TABLE 10—2021 FUEL USE AT LIGNITE-FIRED EGUS

Plant Name	Distillate Fuel Oil (%)	Natural Gas (%)	Lignite Coal (%)	Refined Coal (%)	Subbituminous Coal (%)
Antelope Valley 1	0.0%	0.6%	5.8%	93.5%	0.0%
Antelope Valley 2	0.0%	0.6%	5.8%	93.5%	0.0%
Coal Creek 1	0.1%	0.0%	0.0%	99.9%	0.0%
Coal Creek 2	0.1%	0.0%	0.0%	99.9%	0.0%
Coyote 1	0.3%	0.0%	99.7%	0.0%	0.0%
Leland Olds 1	0.3%	0.0%	37.6%	62.1%	0.0%
Leland Olds 2	0.3%	0.0%	6.2%	93.6%	0.0%
Milton R Young 1	0.4%	0.0%	17.0%	82.6%	0.0%
Milton R Young 2	0.2%	0.0%	12.1%	87.6%	0.0%
Spiritwood Station 1	0.0%	35.6%	0.0%	64.4%	0.0%
Limestone 1	0.0%	0.2%	0.0%	0.0%	99.8%
Limestone 2	0.0%	0.8%	0.0%	0.0%	99.2%
Major Oak Power 1	0.0%	0.2%	99.8%	0.0%	0.0%
Major Oak Power 2	0.0%	0.0%	100.0%	0.0%	0.0%
Martin Lake 1	0.1%	0.0%	23.5%	0.0%	76.4%
Martin Lake 2	0.1%	0.0%	22.4%	0.0%	77.5%
Martin Lake 3	0.1%	0.0%	19.2%	0.0%	80.6%
Oak Grove 1	0.0%	1.9%	3.4%	94.7%	0.0%
Oak Grove 2	0.0%	0.0%	3.7%	96.3%	0.0%
Red Hills Generating Facility 1	0.0%	0.3%	0.0%	99.7%	0.0%
Red Hills Generating Facility 2	0.0%	0.3%	0.0%	99.7%	0.0%
San Miguel 1	0.2%	0.0%	99.8%	0.0%	0.0%

b) Review of the Hg Emission Standard for Non-Lignite-Fired EGUs

The final MATS Hg emission limit for EGUs firing non-lignite coals (*i.e.*, bituminous and subbituminous coals) is 1.2 lb Hg/TBtu. To review that emission standard, the EPA evaluated the 2021 performance of EGUs firing non-lignite coals and found that EGUs firing primarily bituminous coal emitted Hg at an average annual rate of 0.4 lb Hg/TBtu (with a range of roughly 0.2 to 1.2 lb Hg/TBtu). EGUs firing primarily subbituminous coal in 2021 (not including those

EGUs that are permitted to burn lignite but burned a significant amount of subbituminous coal) emitted Hg at an average annual rate of 0.6 lb Hg/TBtu (with a range of 0.1 to 1.2 lb/TBtu). This represents a control range of 98 to 77 percent (assuming an average inlet concentration of 5.5 lb/TBtu). The EPA has information on the control configurations of these non-lignite EGUs but does not have detailed information on the type of sorbent injected (*e.g.*, activated carbon or non-carbonaceous; pre-halogenated, *etc.*). The EPA also does not have detailed information on the injection rate of sorbents used for Hg control (if any). Similarly, the EPA does not have information on the type of quantity of chemical additives used (if any). However, the bituminous coal-fired EGUs are already achieving an average annual rate of 0.4 lb/TBtu and the subbituminous coal-fired EGUs are already achieving an average annual rate of 0.6 lb/TBtu and a level of control of ranging 77 to 98 percent. The typical Hg control performance curves for sorbent injection show a leveling off such that increasing the amount of sorbent results in diminishing improvement in Hg control. Based on full-scale demonstration testing of Hg sorbents, this leveling off takes place somewhere greater than 90 percent capture. Without knowing the type of sorbent being injected or the rate of the sorbent injection, it is difficult to determine whether additional emissions can be achieved in a cost-effective manner. For bituminous coal-fired EGUs that do not utilize sorbent injection but rely on co-benefit control from equipment installed for criteria pollutants, it is difficult to determine whether additional Hg emission reduction could be obtained in a cost-effective manner with knowledge of the levels of Hg control achieved in each of the installed controls and, if chemical additives are injected, the type and rate of chemical additive injection. For those reasons, the EPA is not proposing to adjust the Hg emission standard for non-lignite-fired EGUs.

c) Review of the Hg Emission Standard for Lignite-Fired EGUs

The final MATS Hg emission limit for EGUs firing lignite coal is 4.0 lb Hg/TBtu. To review that emission standard, the EPA evaluated the 2021 performance of lignite-fired EGUs (including those permitted to burn lignite but that utilized significant amounts of subbituminous coal in 2021), shown in Table 11 below. The table shows a “Hg Inlet” level which reflects the maximum Hg content of the range of feedstock coals that the EPA assumes is available to each of the plants in the Integrated Planning Model, IPM,[11] the estimated control (percentage) needed to meet an emission standard of 4.0 lb Hg/TBtu (the current standard for lignite-fired EGUs) and the estimated control (percentage) to meet an emission standard of 1.2 lb Hg/TBtu (the current standard for non-lignite-fired EGUs). The table also shows the estimated 2021 Hg inlet concentration from actual 2021 fuel usage (as mentioned earlier, some units utilized significant quantities of non-lignite fuel, *e.g.*, subbituminous coal, natural gas, *etc.*) and the 2021 Hg emissions reported to the EPA. The EPA then estimated the apparent level of Hg control for 2021 and the level of control that would been needed to achieve the emission standard applicable to the non-lignite-firing EGUs (1.2 lb Hg/TBtu).

[11] Discussion of how these assumptions were developed for use in the EPA’s IPM modeling is available in Chapter 7 of the IPM Documentation.

TABLE 11—HG EMISSIONS AND CONTROL PERFORMANCE OF LIGNITE-FIRED EGUS IN 2021

Plant Name	**Hg Inlet (lb/TBtu)**	**Est Hg Control at 4.0 lb/TBtu (%)**	**Est Hg Control at 1.2 lb/TBtu (%)**	**Est 2021 Hg Inlet (lb/TBtu)**	**2021 Hg Outlet (lb/TBtu)**	**Est 2021 Hg Control (%)**	**Est 2021 Hg Control at 1.2 lb/TBtu (%)**
Antelope Valley #1	7.81	48.8	84.6	7.76	2.87	63.0	84.5
Antelope Valley #2	7.81	48.8	84.6	7.76	2.74	64.6	84.5
Coal Creek #1	7.81	48.8	84.6	7.80	3.62	53.6	84.6
Coal Creek #2	7.81	48.8	84.6	7.80	3.89	50.2	84.6
Coyote	7.81	48.8	84.6	7.79	3.17	59.2	84.6
Leland Olds #1	7.81	48.8	84.6	7.79	2.51	67.8	84.6
Leland Olds #2	7.81	48.8	84.6	7.79	3.02	61.3	84.6
Milton R Young #1	7.81	48.8	84.6	7.78	3.23	58.4	84.6
Milton R Young #2	7.81	48.8	84.6	7.79	3.20	58.9	84.6
Spiritwood Station	7.81	48.8	84.6	5.03	1.86	63.1	76.1
Limestone #1	14.88	73.1	91.9	6.24	0.94	84.9	80.8
Limestone #2	14.88	73.1	91.9	6.20	1.59	74.4	80.7
Major Oak #1	14.65	72.7	91.8	14.62	1.24	91.5	91.8
Major Oak #2	14.65	72.7	91.8	14.65	1.31	91.1	91.8
Martin Lake #1	14.65	72.7	91.8	8.22	2.32	71.8	85.4
Martin Lake #2	14.65	72.7	91.8	8.13	2.99	63.2	85.2
Martin Lake #3	14.65	72.7	91.8	7.85	3.04	61.3	84.7
Oak Grove #1	14.88	73.1	91.9	14.60	2.01	86.2	91.8
Oak Grove #2	14.88	73.1	91.9	14.88	2.59	82.6	91.9
Red Hills #1	12.44	67.8	90.4	12.40	1.33	89.3	90.3
Red Hills #2	12.44	67.8	90.4	12.40	1.35	89.1	90.3
San Miguel	14.65	72.7	91.8	14.62	2.81	80.8	91.8

As can be seen in the table, all lignite-fired EGUs are estimated to meet the current standard by achieving a level of control of less than 75 percent. The average reported 2021 Hg emission rate for lignite-fired EGUs located in North Dakota was 3.0 lb Hg/TBtu with an average control of 83.7 percent. The average reported 2021 Hg emission rate for lignite-fired EGUs located in Texas and Mississippi was 2.0 lb Hg/TBtu (with an average control of 88.2 percent).

d) Determination of an Achievable Hg Emission Standard for Lignite-Fired EGUs

After reviewing the available literature and other studies and available information, the assumptions made regarding Hg control in the final MATS rule, and the information obtained from compliance reports and the 2022 CAA section 114 information collection, the EPA has determined that there are available controls and methods of operation that will allow lignite-fired EGUs to meet an Hg emission standard of 1.2E-06 lb/MMBtu, which is the same emission standard that is being met by EGUs firing on non-lignite coals

i. Both Lignite and Subbituminous Coal are Low Rank Coals with Low Halogen Content

Coal is classified into four main types, or ranks:[12] anthracite, bituminous, subbituminous, and lignite. The ranking depends on heating value of the coal. Anthracite has the highest heating value of all ranks of coal and is mostly used by the metals industry (it is rarely using for power production). Anthracite accounted for less than 1 percent of the coal mined in the U.S. in 2021. Bituminous coal is also considered a "high rank coal" because of its higher heating value. It is the most abundant rank of domestic coal and accounted for about 45 percent of total U.S. coal production in 2021. Bituminous coal is used to generate electricity and in other industries.

Subbituminous coal and lignite are referred to as "low rank coals". They both have lower heating values than bituminous coal. Subbituminous coal accounted for about 46 percent of total U.S. coal production in 2021, with the vast majority produced in the Powder River Basin (PRB) of Wyoming and Montana. Lignite has the lowest energy content of all coal ranks. Lignite accounted for about 8 percent of total U.S. coal production in 2021. About 56 percent was mined in North Dakota (Fort Union lignite) and about 36 percent was mined in Texas (Gulf Coast lignite).

Chlorine is the most abundant halogen in coal. Bromine may also be present in coal but is typically in much lower concentrations than chlorine.[13] Low-rank coals such as lignite and subbituminous generally have lower chlorine contents than higher rank coals such as bituminous coal.[14]

As mentioned earlier, the halogen content of the coal — especially chlorine — largely influences the oxidation state of Hg in the flue gas stream. As a result, the halogen content of the coal directly influences the ability to capture and contain the Hg before it is emitted into the atmosphere. As explained earlier, 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. This makes control of Hg from both subbituminous coal-fired EGUs and lignite-fired EGUs more challenging than the control of Hg from bituminous coal-fired EGUs. However, because control strategies and technologies were developed to introduce halogens to the flue gas stream, EGUs firing subbituminous coals have been able to meet the 1.2 lb/TBtu emission standard in the final MATS rule. 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

[12] "Coal Explained, Types of Coal" Energy Information Administration, available at *www.eia.gov/energyexplained/coal* and in the rulemaking docket.
[13] See Figure 5 in the U.S. Geological Survey publication "Mercury and Halogens in Coal—Their Role in Determining Mercury Emissions From Coal Combustion" available at *https://pubs.usgs.gov/fs/2012/3122/pdf/FS2012-3122_Web.pdf*.
[14] *Ibid*.

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.

ii. The Hg Content of North Dakota Lignite and PRB Subbituminous Coal are Similar

As can be seen in Table 11 above, for the final MATS rule, the EPA estimated the North Dakota lignite-fired EGUs inlet Hg concentration at up to 7.8 lb/TBtu and estimated the inlet Hg concentration of subbituminous coal-fired EGUs at up to 8.65 lb/TBtu. These values are very similar to results from a published study that found the average Hg concentration of North Dakota lignite and PRB subbituminous coals to be very similar. The study found that the North Dakota lignite samples contained an average of 8.5 lb/TBtu and the PRB subbituminous coal samples contained an average of 7.5 lb/TBtu.[15] Despite the similarities in Hg content, halogen content, and alkalinity between North Dakota lignite and PRB subbituminous coal, EGUs firing subbituminous coal in 2021 emitted Hg at an average annual rate of 0.6 lb Hg/TBtu while those firing on North Dakota lignite emitted Hg at an average annual rate of 3.0 lb Hg/TBtu. While the EGUs firing North Dakota lignite at an average emission rate of 3.0 lb Hg/TBtu are complying with the final MATS emission standard of 4.0 lb Hg/TBtu, it is difficult to explain why those units could not meet a similar level of Hg control as that of the EGUs firing PRB subbituminous coal given the similarities between the two fuels – especially the similarities in Hg content, halogen content, and alkalinity.

The Hg content of Gulf Coast lignite tends to be higher than that of the North Dakota lignite. As can be seen in Table 11 above, for the final MATS rule, the EPA estimated the inlet Hg concentration for Gulf Coast lignite-fired EGUs at an average inlet Hg concentration of up to 14.9 lb/TBtu (as compared to average inlet Hg concentrations of up to 7.8 lb/TBtu for North Dakota lignite). Despite the higher Hg content, EGUs permitted as lignite-fired had, in 2021, an average Hg emission rate of 2.0 lb/TBtu – below the 2021 average emission rate of EGUs firing North Dakota lignite (at 3.0 lb/TBtu). This is due, in part, because some EGUs in Texas that are permitted as lignite-fired units (and thus subject to the Hg emission standard of 4.0 lb/TBtu) were, in 2021, firing significant amounts of subbituminous coal. Firing high levels of non-lignite coal (in some cases greater than 99 percent non-lignite coal), while remaining subject to the less stringent Hg emission standard for the subcategory of lignite-fired EGUs seems to fit the scenario that the EPA expressed concern about in the final MATS rule preamble – that "sources to potentially meet the definition by combusting very small amounts of low rank virgin coal [lignite]". *See* 77 FR 9379.

e) Cost of Meeting the Revised Emission Standard

For the final MATS rule, the EPA calculated beyond-the-floor costs for Hg controls by assuming injection of brominated activated carbon at a rate of 3.0 lb/MMacf for units with ESPs and injection rates of 2.0 lb/MMacf for units with baghouses (also known as FF). Yet, in responses to the CAA section 114 information survey, only one facility (Oak Grove) explicitly indicated use of brominated activated carbon. Oak Grove units #1 and #2 (both using FF for PM control) reported use of brominated activated carbon at an average injection rate of less than 0.5

[15] "Mercury in North Dakota lignite", Katrinak, K. A.; Benson, S.A.; Henke, K. R.; Hassett, D. J.; *Fuel Processing Technology*, 39, 35, 1994.

lb/MMacf for operation at capacity factor greater than 70 percent. The Oak Grove units fired, in 2021, using mostly refined coal.[16] That injection rate is considerably less than the 2.0 lb/MMacf assumed.

From the CAA 114 information survey, the average injection rate reported for non-halogenated sorbents was 2.5 lb/MMacf. The average sorbent injection rate ranged from 10 – 65 percent of the maximum design sorbent injection rate (the average was 36 percent of the maximum design rate). As mentioned earlier, most sources utilized a control strategy of sorbent injection coupled with chemical (usually halogenated) additives. In the beyond-the-floor analysis in the final MATS rule, we noted that the results from various demonstration projects suggest that greater than 90 percent Hg control can be achieved at lignite-fired units using brominated activated carbon sorbent at an injection rate of 2.0 lb/MMacf for units with installed FFs for PM control and at an injection rate of 3.0 lb/MMacf for units with installed ESPs for PM control. As shown in Table 11 above, all units (in 2021) would have needed to control their Hg emissions to less than 92 percent to meet an emission standard of 1.2 lb/TBtu. Based on this, we expect that the units could meet the proposed, more stringent, emission standard of 1.2 lb/TBtu by utilizing brominated activated carbon at the injection rates suggested in the beyond-the-floor memo from the final MATS rule.

i. Cost-effectiveness for a Model Plant

To determine the cost-effectiveness of that strategy, we calculated the incremental cost-effectiveness (cost per lb of Hg controlled) for a model 800 MW lignite-fired EGU. We calculated the incremental cost of injecting non-brominated activated carbon sorbent at a conservative injection rate of 5.0 lb/MMacf to achieve an emission rate of 1.2 lb/TBtu versus the cost to meet an emission rate of 4.0 lb/TBtu using non-brominated activated carbon sorbent at an emission rate of 2.5 lb/MMacf.

This calculation assumes a model 800 MW EGU with a heat rate of 11,000 Btu/kWh operating at an 80 percent capacity factor fires Gulf Coast lignite with a Hg concentration of 14.9 lb/TBtu. It also assumes that the unit meets a Hg emission standard of 4.0 lb/TBtu using an injection rate of 2.5 lb/MMacf of non-brominated activated carbon at a sorbent cost of $0.80/lb and that the unit can meet a Hg emission standard of 1.2 lb/TBtu using an injection rate of 5.0 lb/MMacf of brominated activated carbon at a sorbent cost of $1.15/lb.

$$800\ MW\ x\ \left(\frac{8760\ hr}{year}\right) x (80\%\ CF) = 5{,}606{,}400\ \frac{MWh}{year}$$

$$5{,}606{,}400\ \frac{MWh}{year}\ x\ 11\ \frac{mmBtu}{MWh} = 61{,}670{,}400\ \frac{mmBtu}{year} = 8{,}880\ \frac{mmBtu}{hr}$$

$$61{,}670{,}400\ \frac{mmBtu}{year}\ x\ \left(14.9\ x\ 10^{6}\ \frac{lb\ Hg}{mmBtu}\right) = 919\ \frac{lb\ Hg\ in}{year}$$

[16] EIA form 923 does not specify the rank of coal that is “refined.” For this technology review, the EPA has assumed that facilities reporting the use of refined coal have utilized “refined lignite.”

$$At\ an\ emission\ standard\ of\ 4.0\ \frac{lb\ Hg}{TBtu} = 247\ \frac{lb\ Hg}{year}\ emitted\ (73\%\ control)$$

$$2.5\ \frac{lb\ sorbent}{MMacf} x\ 9860 \frac{scf}{mmBtu} x\ \left(\frac{520\ R}{785\ R}\right) x\ 8{,}880\ \frac{mmBtu}{hr}\ x\ \frac{1\ MMacf}{1{,}000{,}000\ acf} = \ 144\ \frac{lb\ sorbent}{hr}$$

$$Sorbent\ cost = \frac{144\ lb}{hr}\ x\ \frac{8760\ hr}{year}\ x\ 80\%\ CF\ x\ \frac{\$0.80}{lb} = \$807{,}322\ per\ year$$

$$At\ an\ emission\ standard\ of\ 1.2\ \frac{lb\ Hg}{TBtu} = 74\ \frac{lb\ Hg}{year}\ emitted\ (92\%\ control)$$

$$5.0\ \frac{lb\ sorbent}{MMacf} x\ 9860 \frac{scf}{mmBtu} x\ \left(\frac{520\ R}{785\ R}\right) x\ 8{,}880\ \frac{mmBtu}{hr}\ x\ \frac{1\ MMacf}{1{,}000{,}000\ acf} = \ 287\ \frac{lb\ sorbent}{hr}$$

$$Sorbent\ cost = \frac{287\ lb}{hr}\ x\ \frac{8760\ hr}{year}\ x\ 80\%\ CF\ x\ \frac{\$1.15}{lb} = \$2{,}312{,}990\ per\ year$$

$$Incremental\ cost\ effectiveness = \frac{(\$2{,}312{,}990 - \$807{,}322)}{(845 - \ 672)\ lb\ Hg\ controlled} = \$8{,}703\ per\ lb\ Hg\ removed$$

This is a conservative value as it is unlikely that sources will need to inject brominated activated carbon sorbent at rates as high as 5.0 lb/MMacf (the Oak Grove units were injecting less than 0.5 lb/MMacf) and is well below the cost that the EPA has found to be acceptable in previous rulemakings. The EPA also calculated unit-level cost-effectiveness to meet the unit's 2021 emission level (shown in Table 12) and to meet the revised, more stringent, emission standard using brominated activated carbon at an injection rate of 5.0 lb/MMacf for units with an ESP for PM control or at an injection rate of 2.5 lb/MMacf for units with FF for PM control (shown in Table 13). In estimating the unit's 2021 cost-effectiveness, the EPA assumed the annual cost of chemical additives to be equivalent to that of annual sorbent costs and the estimated cost-effectiveness ranged from <$1,000 per pound of Hg removed to $13,776 per pound of mercury. The unit level cost-effectiveness to meet the more stringent ranged from $1,675 per pound of Hg controlled to $11,589 per pound of Hg controlled. Each of these calculations is conservative as many EGUs indicated that they have stopped using chemically treated coal (i.e., "refined coal") after the tax credit expired in December 2021. In any case, all calculated cost-effectiveness values are lower than the value ($27,016 per pound of Hg controlled) that was projected in the beyond-the-floor analysis for the final 2012 MATS final rule.[17]

[17] See Docket ID No. EPA-HQ-OAR-2009-0234 at *regulations.gov* or online at *https://www3.epa.gov/airtoxics/utility/2012/BTFMemo_111612.pdf.*

TABLE 12. ESTIMATED COST-EFFECTIVENESS FOR CONTROL OF MERCURY IN 2021 AT LIGNITE-FIRED EGUS

Plant Name	PM Control	Est Hg Inlet (lb/TBtu)	Est Hg In (lb)	2021 Hg (lb/TBtu)	Est Hg Out (lb)	Avg Sorbent injection (lb/MMacf)	Avg Sorbent (lb/hr)	Sorbent Cost ($/lb) **	Est 2021 Sorbent Used (lb)	Est 2021 Sorbent Cost ($)	Est 2021 Additive Cost ($) *	2021 C/E ($/lb)
Spiritwood Station 1	FF	5.03	21.3	1.9	7.9	4.0	13.2	$0.83	111,662	$92,680	$92,680	$13,776
Leland Olds 1	ESPC	7.79	91.8	2.5	29.6	3.9	45.0	**$0.97**	299,689	$290,699	$290,699	$9,343
Leland Olds 2	ESPC	7.79	142.2	3.0	55.1	2.5	55.0	**$0.97**	294,762	$285,919	$285,919	$6,563
Milton R Young 2	ESPC	7.79	130.1	3.2	53.5	1.6	43.0	$0.83	177,431	$147,267	$147,267	$3,844
Milton R Young 1	ESPC	7.78	255.5	3.2	106.2	1.3	19.0	$0.83	273,988	$227,410	$227,410	$3,046
Major Oak Power 1	FF	14.62	193.6	1.2	16.4	1.9	-	**$0.83**	161,759	$134,260	$134,260	$1,515
Major Oak Power 2	FF	14.65	207.0	1.3	18.5	1.9	-	**$0.83**	172,603	$143,261	$143,261	$1,519
Red Hills Generating Facility 1	FF	12.40	192.7	1.3	20.7	2.6	36.0	**$0.76**	259,600	$197,296	$197,296	$2,293
Red Hills Generating Facility 2	FF	12.40	209.4	1.4	22.9	2.4	36.0	**$0.76**	262,834	$199,754	$199,754	$2,141
Oak Grove 1	FF	14.60	980.0	2.0	134.9	0.1	8.0	$1.15	65,331	$75,131	$75,131	$178
Martin Lake 1	ESPC	8.22	392.7	2.3	111.0	1.0	39.0	$0.97	313,150	$303,755	$303,755	$2,156
Oak Grove 2	FF	14.88	887.2	2.6	154.2	0.3	17.0	$1.15	126,484	$145,456	$145,456	$397
San Miguel 1	ESPC	14.62	346.6	2.8	66.7	2.7	59.5	$0.97	418,050	$405,509	$405,509	$2,897
Martin Lake 2	ESPC	8.13	331.1	3.0	121.7	3.0	117.0	$0.97	809,959	$785,660	$785,660	$7,504
Martin Lake 3	ESPC	7.85	372.8	3.0	144.1	3.4	126.0	$0.97	1,046,260	$1,014,872	$1,014,872	$8,877

* Additive costs are unknown. For this analysis, the EPA assumed the additive costs are the same, annually, as the sorbent costs.
** Bolded costs are those that were provided to the EPA in the 2022 CAA section 114 information survey

TABLE 13. ESTIMATED COST-EFFECTIVENESS TO MEET A REVISED MERCURY OF 1.2 LB/TBTU AT LIGNITE-FIRED EGUS (ASSUMING 2021 OPERATIONAL CHARACTERISICS)

Plant Name	PM Control	Est Hg Inlet (lb/TBtu)	Est Hg In (lb)	Hg Out (lb)	Br-ACI rates (lb/MMacf)	Est Br-AC Sorbent Used (lb)	Br-AC cost ($)	C/E ($/lb) assuming no chemical additives	C/E ($/lb) assuming previous chemical additives
Spiritwood Station 1	FF	5.03	21.3	5.09	3.0	83,123	$95,592	$5,884	$11,589
Leland Olds 1	ESPC	7.79	91.8	14.15	5.0	385,175	$442,951	$5,702	$9,444
Leland Olds 2	ESPC	7.79	142.2	21.90	5.0	595,945	$685,337	$5,695	$8,071
Milton R Young 2	ESPC	7.79	130.1	20.05	5.0	545,753	$627,616	$5,702	$7,040
Milton R Young 1	ESPC	7.78	255.5	39.42	5.0	1,072,786	$1,233,703	$5,709	$6,761
Major Oak Power 1	FF	14.62	193.6	15.89	3.0	259,507	$298,433	$1,679	$2,434
Major Oak Power 2	FF	14.65	207.0	16.96	3.0	276,903	$318,439	$1,675	$2,429
Red Hills Generating Facility 1	FF	12.40	192.7	18.65	3.0	304,496	$350,170	$2,011	$3,145
Red Hills Generating Facility 2	FF	12.40	209.4	20.26	3.0	330,893	$380,526	$2,011	$3,067
Oak Grove 1	FF	14.60	980.0	80.56	3.0	1,315,485	$1,512,808	$1,682	$1,765
Martin Lake 1	ESPC	8.22	392.7	57.35	5.0	1,560,741	$1,794,852	$5,352	$6,257
Oak Grove 2	FF	14.88	887.2	71.55	3.0	1,168,333	$1,343,583	$1,647	$1,826
San Miguel 1	ESPC	14.62	346.6	28.45	5.0	774,167	$890,292	$2,798	$4,073
Martin Lake 2	ESPC	8.13	331.1	48.90	5.0	1,330,919	$1,530,557	$5,423	$8,207
Martin Lake 3	ESPC	7.85	372.8	56.99	5.0	1,550,850	$1,783,478	$5,647	$8,861

4. Review of Acid Gas Emission Limits

As described in section III of the preamble, EGUs in six subcategories are subject to numeric emission limits for acid gas HAP (*e.g.*, HCl, HF). Emission standards for HCl serve as a surrogate for the acid gas HAP, with an alternate standard for SO_2 that may be used as a surrogate for acid gas HAP at coal-fired EGUs with operational FGD systems and SO_2 CEMS. For coal-fired EGUs, the acid gas HAP emission standard is 2.0E-03 lb HCl/MMBtu and the alternative SO_2 emission standard is 2.0E-01 lb SO_2/MMBtu.

When the EPA finalized the 2012 MATS rule, the primary air pollution control devices installed at EGUs for the control of acid gases were WS (wet FGD), dry scrubbers (dry FGD or spray dryer absorber, SDA), and reagent injection (at fluidized bed combustors). These technologies are still in wide use currently for acid gas HAP control. An additional acid gas control technology –DSI – was in limited use in the power sector at the time the MATS rule was finalized but has seen increased use since (approximately 20 percent of EGUs operating in 2021 utilized DSI for acid gas control for one reason or another).

A wet FGD scrubber uses an alkaline liquid slurry (usually a limestone or lime slurry) to remove acidic gases from an exhaust stream. The acid gases react with the alkaline compounds in the slurry is removed as scrubber solids (*e.g.*, $CaSO_3$ or $CaSO_4$) or may be captured due to their solubility in the scrubber slurry. Most wet FGD scrubbers have SO_2 removal efficiencies exceeding 90 percent and perform even better for HCl.

Dry FGD scrubbers (SDA) are an acid gas pollution control system where an alkaline sorbent slurry is injected into the flue gas stream to react with and neutralize acid gases in the exhaust stream forming a dry powder material which is then captured in a downstream PM control device (usually a FF).

Alkaline sorbent injection systems (reagent injection) are also used in fluidized bed combustors (FBC) and circulating fluidized bed (CFB) boilers for control of acid gases. In that use, the alkaline sorbent (usually powered limestone) is injected into the combustion chamber with the primary fuel.

DSI is an add-on air pollution control system in which a dry alkaline powdered sorbent (typically sodium- or calcium-based) is injected into the flue gas steam upstream of a PM control device to react with and neutralize acid gases in the exhaust stream forming a dry powder material that may be removed in a primary or secondary PM control device.

The EPA evaluated the use of these control technologies (wet FGD scrubbers, SDA, reagent injection, and DSI), and the strategic use of low sulfur or low halogen fuels.

The EPA reviewed compliance data for SO_2 and/or HCl as shown in Figure 3 below – showing EGUs with highest SO_2 emissions in 2021 to those with the lowest SO_2 emissions in 2021.

Approximately two-thirds of coal-fired EGUs have demonstrated compliance with the alternative SO_2 emission standard rather than the HCl emission limit. Those units are shown on the plot in Figure 3 as the blue data points below the red line indicating the MATS SO_2 emission limit of 0.20 lb/MMBtu. About one-third of EGUs have demonstrated compliance with the primary acid gas emission limit for HCl. And some sources have reported emissions data that demonstrates compliance with either of the standards. Emission rates for HCl are shown in Figure 3 as green data points for EGUs that utilize some sort of acid gas control system – which would be a wet FGD scrubber, a dry scrubber (an SDA), reagent injection or DSI. The purple datapoints on the plot in Figure 3 represent HCl emission rates for units that do not have a wet FGD scrubber or an SDA and do not utilize either reagent injection or DSI. All of those EGUs with no acid gas controls are units that were firing subbituminous coal and were able to demonstrate compliance with the HCl emission standard due to the low natural chlorine content and high alkalinity of most subbituminous coals.

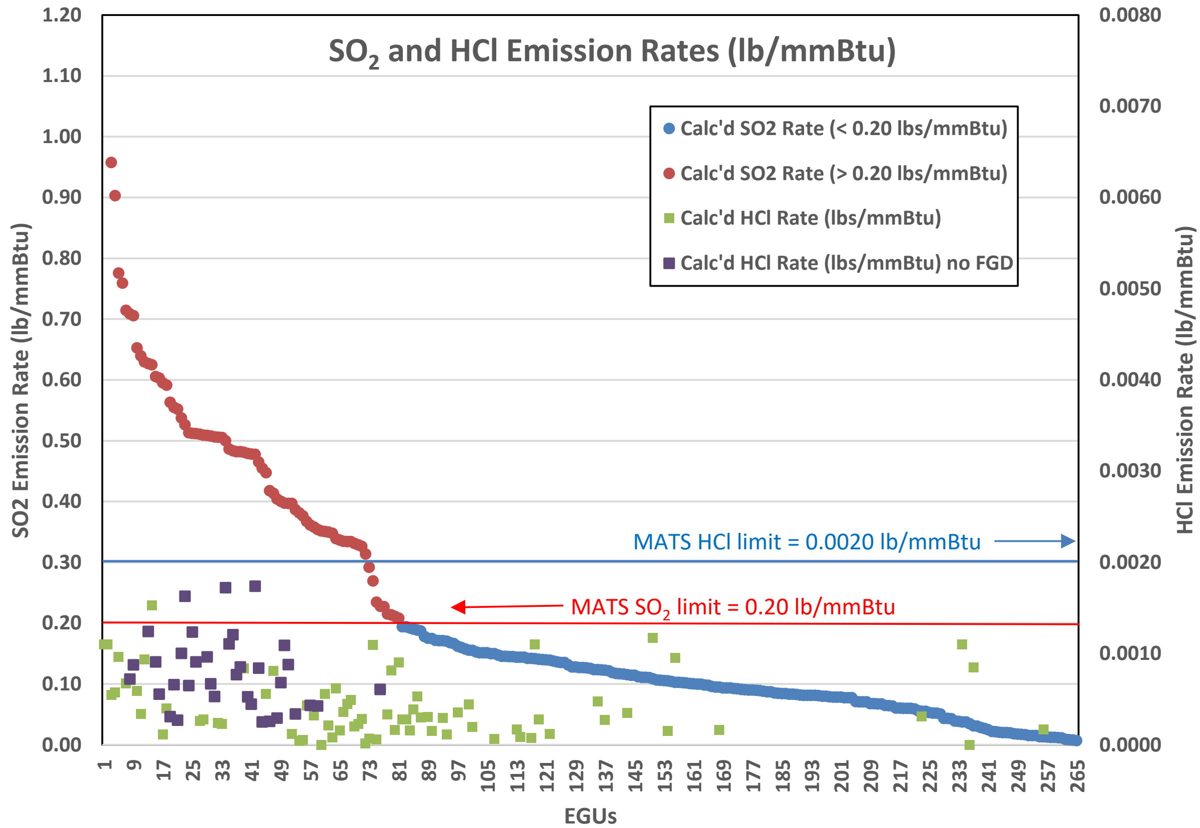

FIGURE 3— SO_2 AND HCL EMISSION RATES FOR COAL-FIRED EGUS OPERATING IN 2021

All sources submit SO_2 emissions data to comply with other CAA requirements (e.g., the Acid Rain Program). As mentioned earlier, some sources submitted emissions data that demonstrates compliance with either the HCl standard or the alternative SO_2 standard. The average SO_2 emission rate for units at or below the alternative SO_2 emission limit was 0.09 lb SO_2/MMBtu, which is approximately 55 percent below the SO_2 emission limit of 0.20 lb SO_2/MMBtu. The average HCl emission rate for units demonstrating compliance with the SO_2 standard but also reporting HCl emissions was 0.0004 lb HCl/MMBtu, which is approximately 80 percent of the HCl emission limit of 0.002 lb HCl/MMBtu. This is consistent with the EPA's rationale for establishing the alternative SO_2 emission limit – because HCl emissions are more easily controlled than SO_2 (it is more reactive and more soluble), controlling emissions of SO_2 using FGD controls effectively controls emissions of HCl. Note that an EGU may demonstrate compliance with the acid gas surrogate SO_2 standard if the unit has some type of installed acid gas control and an operational SO_2 CEMS.

The EPA looked further at the HCl emissions of the EGUs operating in 2021 with and without acid gas controls, as shown in Figure 4 below. The average HCl emission rate of EGUs with some sort of add-on acid gas control (a wet FGD scrubber, a dry scrubber (SDA), reagent injection, or DSI) was 0.0004 lb HCl/MMBtu, which is 80 percent below the HCl emission limit and is the same average HCl emission rate as that of EGUs demonstrating compliance with the alternative SO_2 emission rate (which emphasizes even further that HCl is easier to control than SO_2). Interestingly, the average emission rate of EGUs with no add-on acid gas control was 0.0008 lb HCl/MMBtu, which is 60 percent below the SO_2 emission limit.

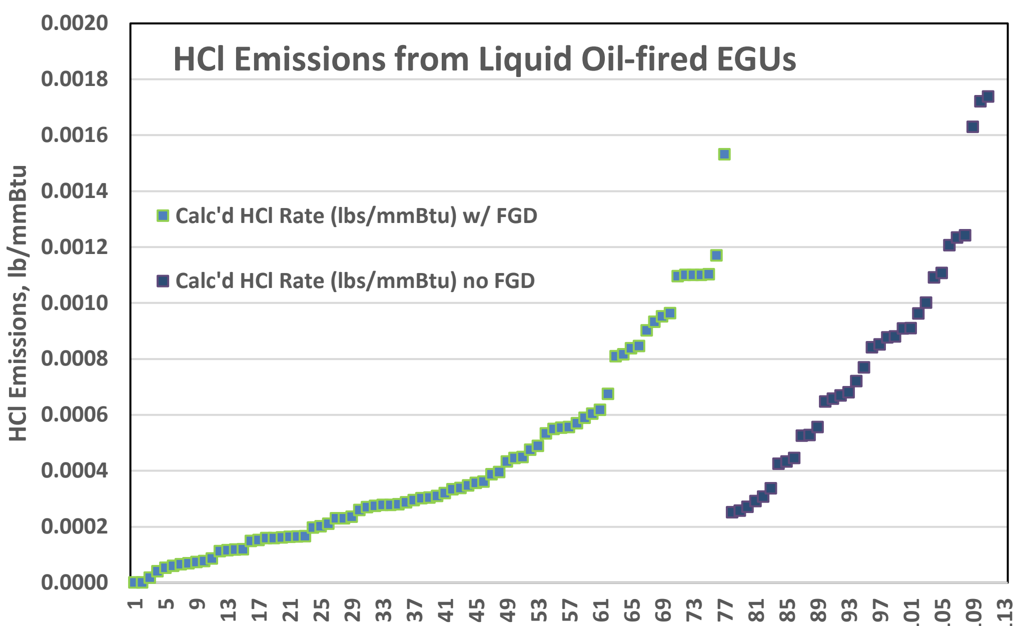

FIGURE 4—HCL EMISSION RATES FOR COAL-FIRED EGUS WITH AND WITHOUT ACID GAS CONTROLS THAT WERE OPERATING IN 2021

The EPA looked closer at the relative performance of acid gas controls for HCl emissions as shown in Figure 5 – showing the HCl emission rates for EGUs operating in 2021 with some sort of acid gas controls installed and demonstrating compliance with the HCl emission standard. Figure 5 shows the performance curve of those EGUs with the units distinguished by the type of acid gas controls – blue data points for units with installed dry scrubbers (SDA), red data points for units with installed wet FGD scrubbers, and green data points for units that used some sort of sorbent injection (either injected into a fluidized boiler or as a downstream DSI system). The best performing EGUs tend to be those that utilize either wet or dry FGD scrubbers, with units utilizing sorbent injection emitting at slightly higher rates. The units that utilize DSI with an FF tend to have lower HCl emissions than those that utilized DSI with an ESP. This is an expected outcome as the filter cake on the FF provides great opportunity for contact with the gas phase acid gases.

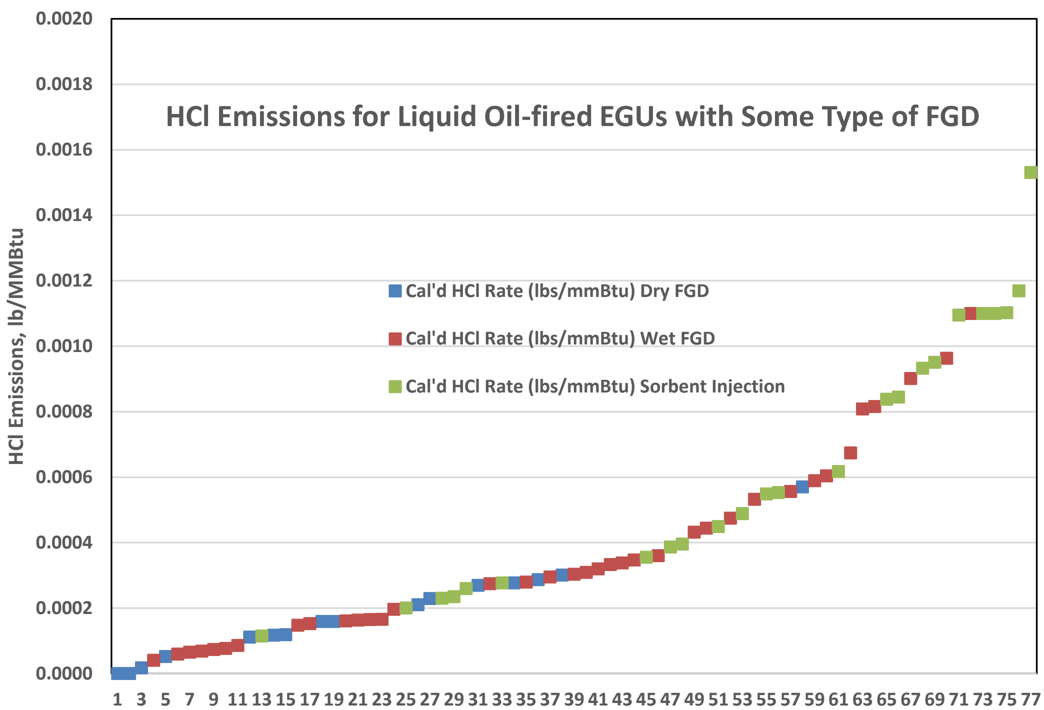

FIGURE 5— HCL EMISSION RATES FOR COAL-FIRED EGUS WITH ACID GAS CONTROLS THAT WERE OPERATING IN 2021 AND DEMONSTRATING COMPLIANCE WITH THE HCL EMISSION STANDARD

Overall, the EPA has evaluated acid gas emissions data from MATS-affected EGUs and has determined that some units have demonstrated compliance with the primary HCl emission standard using acid gas control technologies (wet FGD scrubbers, SDA, reagent injection, and DSI) and through the strategic use of low-halogen, high-alkalinity fuels. Other units have demonstrated compliance with acid gas emission limits using the alternative SO_2 emission standard. The EPA has not identified any new control technologies or any improvements to existing acid gas controls that would result in cost-effective acid gas HAP emission reductions. The average HCl emission rates for units with add-on acid gas controls was 0.0004 lb HCl/MMBtu which is approximately 80 percent below the MATS HCl emission limit. The average HCl emission rate for units with no add-on acid gas controls was 0.0008 lb HCl/MMBtu (approximately 60 percent below the MATS HCl emission limit). It is not clear that improvements in a wet or dry FGD scrubber would result in additional HCl emission reductions since HCl emissions are already much easier to control than SO_2 emissions. The EPA does not have information on the injection rates for DSI systems; so, we cannot assess whether increased sorbent injection rates would result in additional HCl emission reductions. Units using DSI in combination with an ESP would almost certainly see improved performance if they were to replace the ESP with a FF. However, that small incremental reduction in HCl emissions would come at a high cost and would certainly not be a cost-effective option.

Appendix A

Unique ID	**Plant Name**	**Reason**
1012_B_3	F B Culley Generating Station	Reports all units at facility together. Unit 1 retiring in 2024 will not be subject to proposed emission limit.
10684_B_BLR25, 10684_B_BLR26	Argus Cogen Plant	Not in WebFIRE
10784	Colstrip	Data not pulled
10849_B_BLR1, 10849_B_BLR2	Silver Bay Power	Not in WebFIRE
10864_B_1, 10864_B_2, 10864_B_3, 10864_B_4	Archer Daniels Midland Cedar Rapids	No data
130_B_2	Cross	CPMS
1393_B_1A, 1393_B_2A	R S Nelson	Not in WebFIRE; burns petroleum coke
1893_B_3	Clay Boswell	Reported units 1, 2, and 3 together. Units 1 and 2 retired.
2718_B_5	G G Allen	Reported data with units 1 and 2 which will retire by proposed compliance date.
2878_B_1	FirstEnergy Bay Shore	Reports in lb/MWh
2952_B_6	Muskogee	CPMS
3122_B_1, 3122_B_2, 3122_B_3	Homer City Generating Station	Reports in lb/MWh
3943_B_1, 3943_B_2	FirstEnergy Fort Martin Power Station	Reports in lb/MWh
3944_B_1, 3944_B_2, 3944_B_3	FirstEnergy Harrison Power Station	Reports in lb/MWh
50397_B_5PB036	Pixelle Specialty Solutions LLC – Spring Grove Facility	Not in WebFIRE
50931_B_BLR1, 50931_B_BLR2	Yellowstone Energy LP	Burns petroleum coke (subject to different numeric standard)
55856_G_PC1, 55856_G_PC2	Prairie State Generating Station	Coding error
56564_G_SN-01	John W Turk Jr Power Plant	Coding error
56808_G_1, 56808_G_2	Virginia City Hybrid Energy Center	Coding error

57046_B_CFB1, 57046_B_CFB2	Archer Daniels Midland Columbus	Not in WebFIRE
57953_B_ST	Roquette America	Not in WebFIRE
6095_B_1	Sooner	CPMS
6249_B_1, 6249_B_2, 6249_B_3, 6249_B_4	Winyah	CPMS
6705_B_1, 6705_B_2, 6705_B_3	Alcoa Allowance (IN)	Not in WebFIRE

Appendix B

Unique ID	Plant Name	Min Max	Min 99th	Min 90th	Min 85th	Min 80th	Min 75th	Min 50th
6076_B_4	Colstrip	2.70 E-02	2.10 E-02	2.10 E-02	2.00 E-02	2.00 E-02	2.00 E-02	1.90 E-02
10343_B_SG-101	Foster Wheeler Mt Carmel Cogen	1.80 E-02	1.80 E-02	1.80 E-02	1.80 E-02	1.80 E-02	1.80 E-02	1.80 E-02
6076_B_3	Colstrip	1.80 E-02	1.80 E-02	1.80 E-02	1.80 E-02	1.80 E-02	1.80 E-02	1.70 E-02
2103_B_2	Labadie	1.80 E-02	1.70 E-02	1.70 E-02	1.70 E-02	1.70 E-02	1.60 E-02	1.60 E-02
2103_B_1	Labadie	1.80 E-02	1.70 E-02	1.70 E-02	1.70 E-02	1.70 E-02	1.60 E-02	1.60 E-02
2103_B_4	Labadie	1.80 E-02	1.70 E-02	1.70 E-02	1.70 E-02	1.70 E-02	1.60 E-02	1.60 E-02
2103_B_3	Labadie	1.80 E-02	1.70 E-02	1.70 E-02	1.70 E-02	1.70 E-02	1.60 E-02	1.60 E-02
976_B_123	Marion	1.70 E-02	1.70 E-02	1.70 E-02	1.60 E-02	1.60 E-02	1.60 E-02	1.50 E-02
10113_B_CFB1, 10113_B_CFB2	John B Rich Memorial Power Station	1.60 E-02	1.50 E-02	1.50 E-02	1.50 E-02	1.50 E-02	1.50 E-02	1.40 E-02
6823_B_W1	D B Wilson	1.50 E-02	1.50 E-02	1.50 E-02	1.50 E-02	1.50 E-02	1.50 E-02	9.00 E-03
50611_B_031	Westwood Generation LLC	1.50 E-02	1.50 E-02	1.40 E-02	1.40 E-02	1.40 E-02	1.40 E-02	1.30 E-02
6146_B_1	Martin Lake	1.40 E-02	1.40 E-02	1.40 E-02	1.30 E-02	1.30 E-02	1.30 E-02	1.20 E-02
6041_B_3	H L Spurlock	1.20 E-02	1.20 E-02	1.20 E-02	1.10 E-02	1.00 E-02	9.20 E-03	8.00 E-03
3954_B_3	Mt Storm	1.20 E-02	1.20 E-02	1.20 E-02	1.10 E-02	1.10 E-02	1.10 E-02	1.10 E-02
6146_B_3	Martin Lake	1.20 E-02	1.20 E-02	1.10 E-02	1.10 E-02	1.10 E-02	1.10 E-02	1.00 E-02
1082_B_3	Walter Scott Jr Energy Center	1.10 E-02	1.10 E-02	1.10 E-02	1.10 E-02	1.10 E-02	1.10 E-02	1.00 E-02
3954_B_1, 3954_B_2	Mt Storm	1.10 E-02	1.10 E-02	1.10 E-02	1.00 E-02	1.00 E-02	1.00 E-02	1.00 E-02
1893_B_4	Clay Boswell	1.10 E-02	1.10 E-02	9.00 E-03	8.10 E-03	7.90 E-03	7.70 E-03	7.20 E-03
10143_B_ABB01	Colver Power Project	1.10 E-02	1.00 E-02	1.00 E-02	1.00 E-02	1.00 E-02	1.00 E-02	1.00 E-02
54634_B_1	St Nicholas Cogen Project	1.50 E-02	1.00 E-02	1.00 E-02	1.00 E-02	9.90 E-03	9.70 E-03	9.00 E-03
8102_B_1	Gavin Power, LLC	1.00 E-02	1.00 E-02	1.00 E-02	1.00 E-02	1.00 E-02	1.00 E-02	9.60 E-03

Unique ID	Plant Name	Min Max	Min 99th	Min 90th	Min 85th	Min 80th	Min 75th	Min 50th
2823_B_B2	Milton R Young	1.00 E-02	1.00 E-02	1.00 E-02	1.00 E-02	1.00 E-02	1.00 E-02	1.00 E-02
6018_B_2	East Bend	1.20 E-02	9.90 E-03	9.80 E-03	9.60 E-03	9.60 E-03	9.50 E-03	8.20 E-03
6113_B_3	Gibson	9.90 E-03	9.80 E-03	9.50 E-03	9.50 E-03	9.30 E-03	8.80 E-03	7.70 E-03
6065_B_2	Iatan	9.00 E-03	9.00 E-03	8.00 E-03	8.00 E-03	8.00 E-03	7.00 E-03	6.00 E-03
645_B_BB04	Big Bend	6.20 E-02	9.00 E-03	6.00 E-03	5.00 E-03	4.00 E-03	4.00 E-03	1.00 E-03
6068_B_3	Jeffrey Energy Center	9.00 E-03	9.00 E-03	8.80 E-03	8.60 E-03	8.50 E-03	8.40 E-03	7.80 E-03
6177_B_U2B	Coronado	8.70 E-03	8.60 E-03	8.30 E-03	8.00 E-03	7.90 E-03	7.90 E-03	7.60 E-03
6177_B_U1B	Coronado	8.70 E-03	8.60 E-03	8.30 E-03	8.00 E-03	7.90 E-03	7.90 E-03	7.60 E-03
6183_B_SM-1	San Miguel	8.20 E-03	8.20 E-03	8.10 E-03	8.00 E-03	8.00 E-03	7.90 E-03	7.70 E-03
6705_B_4	Warrick	9.00 E-03	8.20 E-03	6.00 E-03	6.00 E-03	6.00 E-03	5.00 E-03	4.00 E-03
628_B_5	Crystal River	8.20 E-03	8.10 E-03	8.10 E-03	8.00 E-03	7.90 E-03	7.80 E-03	7.50 E-03
628_B_4	Crystal River	8.20 E-03	8.10 E-03	8.10 E-03	8.00 E-03	7.90 E-03	7.80 E-03	7.50 E-03
1356_B_2, 1356_B_3	Ghent	8.10 E-03	8.10 E-03	8.00 E-03	7.70 E-03	7.60 E-03	7.50 E-03	7.30 E-03
6146_B_2	Martin Lake	8.00 E-03	8.00 E-03	8.00 E-03	7.00 E-03	6.00 E-03	6.00 E-03	5.00 E-03
6180_B_1	Oak Grove (TX)	8.00 E-03	8.00 E-03	7.00 E-03	7.00 E-03	7.00 E-03	6.00 E-03	5.00 E-03
6204_B_2	Laramie River Station	8.00 E-03	8.00 E-03	8.00 E-03	8.00 E-03	8.00 E-03	8.00 E-03	8.00 E-03
136_B_2	Seminole (FL)	1.00 E-02	8.00 E-03	7.80 E-03	7.70 E-03	7.60 E-03	7.50 E-03	7.00 E-03
2364_B_1, 2364_B_2	Merrimack	7.90 E-03	7.90 E-03	7.50 E-03	7.30 E-03	7.10 E-03	7.00 E-03	6.00 E-03
1393_B_6	R S Nelson	7.90 E-03	7.90 E-03	7.60 E-03	7.60 E-03	7.60 E-03	7.60 E-03	7.50 E-03
8066_B_BW73	Jim Bridger	7.80 E-03	7.80 E-03	7.70 E-03	7.60 E-03	7.60 E-03	7.50 E-03	7.30 E-03
8066_B_BW74	Jim Bridger	7.80 E-03	7.80 E-03	7.70 E-03	7.60 E-03	7.60 E-03	7.50 E-03	7.20 E-03
6664_B_101	Louisa	7.30 E-03	7.30 E-03	7.20 E-03	7.20 E-03	7.20 E-03	7.20 E-03	7.00 E-03

Unique ID	Plant Name	Min Max	Min 99th	Min 90th	Min 85th	Min 80th	Min 75th	Min 50th
7030_B_U2	Major Oak Power	7.00 E-03	7.00 E-03	7.00 E-03	7.00 E-03	7.00 E-03	7.00 E-03	7.00 E-03
1733_B_2	Monroe (MI)	7.00 E-03	7.00 E-03	6.00 E-03	6.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03
4078_B_3	Weston	7.00 E-03	7.00 E-03	7.00 E-03	6.00 E-03	6.00 E-03	6.00 E-03	6.00 E-03
2817_B_1	Leland Olds	7.00 E-03	7.00 E-03	6.90 E-03	6.90 E-03	6.80 E-03	6.80 E-03	6.60 E-03
50974_B_UNIT 1	Scrubgrass Generating Plant	7.00 E-03	7.00 E-03	6.80 E-03	6.70 E-03	6.60 E-03	6.50 E-03	6.00 E-03
50974_B_UNIT 2	Scrubgrass Generating Plant	7.00 E-03	7.00 E-03	6.80 E-03	6.70 E-03	6.60 E-03	6.50 E-03	6.00 E-03
7030_B_U1	Major Oak Power	7.00 E-03	7.00 E-03	6.80 E-03	6.70 E-03	6.60 E-03	6.50 E-03	6.00 E-03
6469_B_B1	Antelope Valley	7.00 E-03	7.00 E-03	6.70 E-03	6.50 E-03	6.30 E-03	6.20 E-03	5.30 E-03
7790_B_1-1	Bonanza	7.00 E-03	7.00 E-03	6.60 E-03	6.40 E-03	6.20 E-03	6.00 E-03	5.00 E-03
8069_B_2	Huntington	7.00 E-03	6.90 E-03	6.40 E-03	6.10 E-03	5.80 E-03	5.50 E-03	4.00 E-03
8042_B_2	Belews Creek	3.40 E-02	6.90 E-03	4.20 E-03	4.20 E-03	4.10 E-03	4.10 E-03	3.90 E-03
60_B_1	Whelan Energy Center	6.80 E-03	6.80 E-03	6.80 E-03	6.70 E-03	6.70 E-03	6.70 E-03	6.50 E-03
470_B_3	Comanche (CO)	6.80 E-03	6.80 E-03	6.70 E-03	6.50 E-03	6.40 E-03	6.30 E-03	6.20 E-03
6096_B_2	Nebraska City	6.80 E-03	6.80 E-03	6.80 E-03	6.70 E-03	6.70 E-03	6.70 E-03	6.60 E-03
6009_B_2	White Bluff	6.40 E-03	6.40 E-03	6.20 E-03	6.10 E-03	6.10 E-03	6.00 E-03	5.80 E-03
56611_B_S01	Sandy Creek Energy Station	6.30 E-03	6.30 E-03	5.80 E-03	5.60 E-03	5.30 E-03	5.00 E-03	3.80 E-03
6179_B_2	Fayette Power Project	6.10 E-03	6.10 E-03	4.50 E-03	4.50 E-03	4.30 E-03	4.00 E-03	3.80 E-03
1733_B_1	Monroe (MI)	7.00 E-03	6.10 E-03	4.00 E-03	4.00 E-03	4.00 E-03	4.00 E-03	4.00 E-03
6113_B_1	Gibson	6.00 E-03	6.00 E-03	6.00 E-03	5.80 E-03	5.70 E-03	5.50 E-03	5.40 E-03
1356_B_4	Ghent	6.30 E-03	6.00 E-03	6.00 E-03	6.00 E-03	6.00 E-03	6.00 E-03	5.70 E-03
7213_B_2	Clover	6.00 E-03	6.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03
6180_B_2	Oak Grove (TX)	6.00 E-03	6.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03

Unique ID	Plant Name	Min Max	Min 99th	Min 90th	Min 85th	Min 80th	Min 75th	Min 50th
4162_B_1	Naughton	6.00 E-03	6.00 E-03	5.80 E-03	5.70 E-03	5.60 E-03	5.50 E-03	5.00 E-03
6204_B_3	Laramie River Station	6.00 E-03	6.00 E-03	5.80 E-03	5.70 E-03	5.60 E-03	5.50 E-03	5.00 E-03
50951_B_1	Sunnyside Cogen Associates	6.00 E-03	6.00 E-03	5.80 E-03	5.70 E-03	5.60 E-03	5.50 E-03	5.00 E-03
6639_B_G1	R D Green	5.90 E-03	5.90 E-03	5.80 E-03	5.80 E-03	5.70 E-03	5.70 E-03	5.50 E-03
56456_B_BLR1	Plum Point Energy Station	5.80 E-03	5.80 E-03	5.50 E-03	5.40 E-03	5.30 E-03	5.20 E-03	4.50 E-03
2817_B_2	Leland Olds	5.70 E-03	5.70 E-03	5.60 E-03	5.60 E-03	5.50 E-03	5.50 E-03	5.30 E-03
3140_B_1, 3140_B_2	Brunner Island	5.70 E-03	5.70 E-03	5.40 E-03	5.30 E-03	5.20 E-03	5.10 E-03	3.70 E-03
2367_B_6	Schiller	5.70 E-03	5.70 E-03	5.30 E-03	5.10 E-03	4.90 E-03	4.60 E-03	3.60 E-03
1379_B_6, 1379_B_7, 1379_B_8, 1379_B_9	Shawnee	5.60 E-03	5.60 E-03	5.50 E-03	5.40 E-03	5.40 E-03	5.40 E-03	5.10 E-03
56671_B_UHA01	Longview Power Plant	5.50 E-03	5.50 E-03	4.80 E-03	4.30 E-03	3.80 E-03	3.50 E-03	2.30 E-03
6068_B_2	Jeffrey Energy Center	5.50 E-03	5.50 E-03	5.40 E-03	5.40 E-03	5.40 E-03	5.20 E-03	4.30 E-03
1379_B_1, 1379_B_2, 1379_B_3, 1379_B_4, 1379_B_5	Shawnee	5.50 E-03	5.50 E-03	5.20 E-03	5.00 E-03	4.90 E-03	4.70 E-03	4.00 E-03
994_B_4	AES Petersburg	5.40 E-03	5.40 E-03	5.20 E-03	5.00 E-03	4.90 E-03	4.80 E-03	3.20 E-03
994_B_3	AES Petersburg	5.40 E-03	5.40 E-03	5.20 E-03	5.00 E-03	4.90 E-03	4.80 E-03	3.20 E-03
6641_B_1	Independence Steam Electric Station	5.40 E-03	5.40 E-03	5.20 E-03	5.10 E-03	5.10 E-03	5.00 E-03	4.60 E-03
6009_B_1	White Bluff	5.40 E-03	5.40 E-03	5.20 E-03	5.10 E-03	5.10 E-03	4.50 E-03	4.50 E-03
6179_B_1	Fayette Power Project	5.30 E-03	5.30 E-03	5.30 E-03	5.30 E-03	5.30 E-03	5.30 E-03	5.20 E-03
6002_B_3	James H Miller Jr	5.40 E-03	5.30 E-03	5.00 E-03	4.90 E-03	4.70 E-03	4.50 E-03	3.70 E-03
2828_B_3	Cardinal	5.20 E-03	5.20 E-03	5.20 E-03	5.10 E-03	5.10 E-03	5.10 E-03	5.00 E-03
6193_B_063B	Harrington	5.20 E-03	5.20 E-03	5.10 E-03	5.00 E-03	5.00 E-03	4.90 E-03	4.70 E-03
6071_B_2	Trimble County	5.20 E-03	5.10 E-03	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03	4.90 E-03

Unique ID	Plant Name	Min Max	Min 99th	Min 90th	Min 85th	Min 80th	Min 75th	Min 50th
1356_B_1	Ghent	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03	4.90 E-03
4162_B_2	Naughton	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03
1384_B_1, 1384_B_2	Cooper	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03
6254_B_1	Ottumwa	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03
2107_B_2	Sioux	5.00 E-03	5.00 E-03	5.00 E-03	5.00 E-03	4.00 E-03	4.00 E-03	4.00 E-03
2167_B_2	New Madrid	5.00 E-03	5.00 E-03	4.80 E-03	4.70 E-03	4.60 E-03	4.50 E-03	4.00 E-03
2167_B_1	New Madrid	5.00 E-03	5.00 E-03	4.80 E-03	4.70 E-03	4.60 E-03	4.50 E-03	4.00 E-03
6165_B_1	Hunter	5.00 E-03	5.00 E-03	4.60 E-03	4.40 E-03	4.20 E-03	4.00 E-03	3.00 E-03
6213_B_2SG1	Merom	5.00 E-03	5.00 E-03	4.60 E-03	4.40 E-03	4.20 E-03	4.00 E-03	3.00 E-03
26_B_5	E C Gaston	5.00 E-03	4.90 E-03	4.40 E-03	4.10 E-03	3.80 E-03	3.50 E-03	2.00 E-03
6761_B_101	Rawhide	4.90 E-03	4.90 E-03	4.80 E-03	4.70 E-03	4.70 E-03	4.60 E-03	4.30 E-03
2876_B_3, 2876_B_4, 2876_B_5	Kyger Creek	4.90 E-03	4.80 E-03	4.80 E-03	4.80 E-03	4.70 E-03	4.70 E-03	4.60 E-03
1082_B_4	Walter Scott Jr Energy Center	4.80 E-03	4.80 E-03	4.80 E-03	4.80 E-03	4.80 E-03	4.70 E-03	4.70 E-03
6639_B_G2	R D Green	4.80 E-03	4.80 E-03	4.50 E-03	4.30 E-03	4.20 E-03	4.00 E-03	3.30 E-03
6034_B_1	Belle River	1.10 E-02	4.60 E-03	2.00 E-03	2.00 E-03	2.00 E-03	0.00 E+00	0.00 E+00
6096_B_1	Nebraska City	5.70 E-03	4.60 E-03	3.80 E-03	3.30 E-03	2.80 E-03	2.80 E-03	2.60 E-03
2291_B_5	North Omaha	4.60 E-03	4.60 E-03	4.40 E-03	4.40 E-03	4.30 E-03	4.20 E-03	3.80 E-03
10151_B_BLR1A, 10151_B_BLR1B	Grant Town Power Plant	6.20 E-03	4.50 E-03	4.40 E-03	4.30 E-03	4.30 E-03	4.20 E-03	3.90 E-03
6113_B_2	Gibson	4.50 E-03	4.50 E-03	4.20 E-03	4.20 E-03	4.10 E-03	4.00 E-03	3.80 E-03
6113_B_4	Gibson	4.50 E-03	4.40 E-03	3.80 E-03	3.50 E-03	3.30 E-03	3.30 E-03	3.30 E-03
8223_B_2	Springerville	4.30 E-03	4.30 E-03	4.20 E-03	4.20 E-03	4.20 E-03	4.20 E-03	4.00 E-03

Unique ID	Plant Name	Min Max	Min 99th	Min 90th	Min 85th	Min 80th	Min 75th	Min 50th
160_B_3	Apache Station	4.20 E-03	4.20 E-03	4.00 E-03	3.90 E-03	3.80 E-03	3.70 E-03	3.30 E-03
6071_B_1	Trimble County	4.20 E-03	4.20 E-03	4.10 E-03	4.10 E-03	4.00 E-03	4.00 E-03	3.60 E-03
6641_B_2	Independence Steam Electric Station	4.20 E-03	4.10 E-03	3.80 E-03	3.50 E-03	3.40 E-03	3.20 E-03	3.10 E-03
1091_B_3	George Neal North	4.10 E-03	4.10 E-03	3.90 E-03	3.90 E-03	3.80 E-03	3.70 E-03	2.80 E-03
59_B_1	Platte	4.10 E-03	4.10 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03
2823_B_B1	Milton R Young	4.00 E-03	4.00 E-03	4.00 E-03	4.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03
6021_B_C3	Craig (CO)	4.00 E-03	4.00 E-03	4.00 E-03	4.00 E-03	4.00 E-03	4.00 E-03	4.00 E-03
8069_B_1	Huntington	4.00 E-03	4.00 E-03	4.00 E-03	4.00 E-03	4.00 E-03	4.00 E-03	4.00 E-03
6002_B_4	James H Miller Jr	4.00 E-03	4.00 E-03	4.00 E-03	4.00 E-03	4.00 E-03	4.00 E-03	4.00 E-03
1733_B_3	Monroe (MI)	4.00 E-03	4.00 E-03	4.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03
6041_B_4	H L Spurlock	4.00 E-03	4.00 E-03	4.00 E-03	4.00 E-03	4.00 E-03	4.00 E-03	4.00 E-03
6264_B_1	Mountaineer	4.00 E-03	4.00 E-03	3.90 E-03	3.90 E-03	3.80 E-03	3.70 E-03	3.50 E-03
6213_B_1SG1	Merom	4.00 E-03	4.00 E-03	3.80 E-03	3.70 E-03	3.60 E-03	3.50 E-03	3.00 E-03
6002_B_1	James H Miller Jr	4.00 E-03	4.00 E-03	3.80 E-03	3.70 E-03	3.60 E-03	3.50 E-03	3.00 E-03
2442_B_4	Four Corners	4.00 E-03	4.00 E-03	3.80 E-03	3.70 E-03	3.60 E-03	3.50 E-03	3.00 E-03
6002_B_2	James H Miller Jr	4.00 E-03	4.00 E-03	3.80 E-03	3.70 E-03	3.60 E-03	3.50 E-03	3.00 E-03
1040_B_1, 1040_B_2	Whitewater Valley	4.00 E-03	4.00 E-03	3.80 E-03	3.70 E-03	3.60 E-03	3.50 E-03	2.00 E-03
4158_B_BW43	Dave Johnston	4.00 E-03	4.00 E-03	3.80 E-03	3.70 E-03	3.60 E-03	3.50 E-03	3.00 E-03
3399_B_1	Cumberland (TN)	3.90 E-03	3.90 E-03	3.90 E-03	3.80 E-03	3.80 E-03	3.80 E-03	3.70 E-03
8102_B_2	Gavin Power, LLC	5.90 E-03	3.90 E-03	3.80 E-03	3.70 E-03	3.70 E-03	3.60 E-03	3.30 E-03
10603_B_031	Ebensburg Power	3.90 E-03	3.90 E-03	3.80 E-03	3.70 E-03	3.70 E-03	3.60 E-03	3.30 E-03
3130_B_1, 3130_B_2	Seward (PA)	3.80 E-03	3.80 E-03	3.70 E-03	3.70 E-03	3.70 E-03	3.70 E-03	3.40 E-03

Unique ID	Plant Name	Min Max	Min 99th	Min 90th	Min 85th	Min 80th	Min 75th	Min 50th
6179_B_3	Fayette Power Project	3.80 E-03	3.80 E-03	3.80 E-03	3.60 E-03	3.50 E-03	3.40 E-03	3.00 E-03
6077_B_2	Gerald Gentleman	3.80 E-03	3.80 E-03	3.70 E-03	3.70 E-03	3.70 E-03	3.60 E-03	3.50 E-03
55076_B_AA001, 55076_B_AA002	Red Hills Generating Facility	1.80 E-02	3.70 E-03	3.70 E-03	3.60 E-03	3.60 E-03	3.60 E-03	3.50 E-03
10671_B_1A, 10671_B_1B, 10671_B_2A, 10671_B_2B	River Valley	5.70 E-03	3.70 E-03	3.60 E-03	3.60 E-03	3.60 E-03	3.60 E-03	3.40 E-03
2277_B_1	Sheldon	3.60 E-03	3.60 E-03	3.60 E-03	3.60 E-03	3.50 E-03	3.50 E-03	3.40 E-03
1167_B_9	Muscatine Plant #1	3.60 E-03	3.60 E-03	3.60 E-03	3.60 E-03	3.60 E-03	3.60 E-03	3.60 E-03
50888_B_BLR1	Northampton Generating Company LP	3.60 E-03	3.60 E-03	3.60 E-03	3.60 E-03	3.60 E-03	3.60 E-03	3.50 E-03
1364_B_4	Mill Creek (KY)	3.50 E-03	3.50 E-03	3.40 E-03	3.40 E-03	3.40 E-03	3.40 E-03	3.40 E-03
3948_B_1	Mitchell (WV)	3.50 E-03	3.50 E-03	3.50 E-03	3.50 E-03	3.50 E-03	3.50 E-03	1.70 E-03
3935_B_1	John E Amos	3.50 E-03	3.50 E-03	3.20 E-03	3.00 E-03	2.90 E-03	2.70 E-03	2.00 E-03
6469_B_B2	Antelope Valley	3.40 E-03	3.40 E-03	3.40 E-03	3.40 E-03	3.40 E-03	3.40 E-03	3.40 E-03
6166_B_MB1, 6166_B_MB2	Rockport	3.40 E-03	3.40 E-03	3.10 E-03	3.00 E-03	2.90 E-03	2.70 E-03	2.10 E-03
983_B_1, 983_B_2, 983_B_3	Clifty Creek	3.20 E-03	3.20 E-03	3.20 E-03	3.20 E-03	3.10 E-03	3.10 E-03	3.10 E-03
3403_B_2	Gallatin (TN)	3.10 E-03	3.10 E-03	3.10 E-03	3.10 E-03	3.10 E-03	3.00 E-03	3.00 E-03
2168_B_MB2	Thomas Hill	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03
10678_B_BLR1	AES Warrior Run Cogeneration Facility	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03
2168_B_MB3	Thomas Hill	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03
1733_B_4	Monroe (MI)	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03
6165_B_3	Hunter	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03
2107_B_1	Sioux	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03
703_B_3BLR	Bowen	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03

Unique ID	Plant Name	Min Max	Min 99th	Min 90th	Min 85th	Min 80th	Min 75th	Min 50th
6064_B_N1	Nearman Creek	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03
3403_B_1	Gallatin (TN)	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	3.00 E-03	2.90 E-03	2.90 E-03
4158_B_BW41	Dave Johnston	3.00 E-03	3.00 E-03	2.80 E-03	2.70 E-03	2.60 E-03	2.50 E-03	2.00 E-03
6030_B_1	Coal Creek	3.00 E-03	3.00 E-03	2.80 E-03	2.70 E-03	2.60 E-03	2.50 E-03	2.00 E-03
4158_B_BW42	Dave Johnston	3.00 E-03	3.00 E-03	2.80 E-03	2.70 E-03	2.60 E-03	2.50 E-03	2.00 E-03
56596_B_1	Wygen III	3.00 E-03	3.00 E-03	2.80 E-03	2.70 E-03	2.60 E-03	2.50 E-03	2.00 E-03
6165_B_2	Hunter	3.00 E-03	3.00 E-03	2.80 E-03	2.70 E-03	2.60 E-03	2.50 E-03	2.00 E-03
10743_B_CFB1, 10743_B_CFB2	Morgantown Energy Facility	3.00 E-03	3.00 E-03	2.80 E-03	2.70 E-03	2.60 E-03	2.50 E-03	2.00 E-03
56319_B_1	Wygen 2	3.00 E-03	3.00 E-03	2.80 E-03	2.70 E-03	2.60 E-03	2.50 E-03	2.00 E-03
2828_B_1	Cardinal	3.00 E-03	3.00 E-03	2.60 E-03	2.40 E-03	2.20 E-03	2.10 E-03	1.10 E-03
6768_B_1	Sikeston Power Station	2.90 E-03	2.90 E-03	2.80 E-03	2.70 E-03	2.60 E-03	2.50 E-03	2.20 E-03
130_B_4	Cross	2.90 E-03	2.90 E-03	2.90 E-03	2.90 E-03	2.90 E-03	2.90 E-03	2.80 E-03
2442_B_5	Four Corners	2.90 E-03	2.90 E-03	2.90 E-03	2.80 E-03	2.80 E-03	2.80 E-03	2.70 E-03
6772_B_1	Hugo	2.90 E-03	2.90 E-03	2.70 E-03	2.60 E-03	2.50 E-03	2.40 E-03	1.90 E-03
298_B_LIM2	Limestone	2.90 E-03	2.90 E-03	2.70 E-03	2.70 E-03	2.60 E-03	2.50 E-03	2.10 E-03
50776_B_BLR1, 50776_B_BLR2	Panther Creek Energy Facility	2.90 E-03	2.80 E-03	2.80 E-03	2.80 E-03	2.80 E-03	2.80 E-03	2.80 E-03
6195_B_1	John Twitty Energy Center	2.80 E-03	2.80 E-03	2.60 E-03	2.40 E-03	2.30 E-03	2.20 E-03	1.50 E-03
6077_B_1	Gerald Gentleman	2.80 E-03	2.80 E-03	2.70 E-03	2.70 E-03	2.70 E-03	2.70 E-03	2.70 E-03
3948_B_2	Mitchell (WV)	2.70 E-03	2.70 E-03	2.60 E-03	2.60 E-03	2.60 E-03	2.60 E-03	2.40 E-03
6068_B_1	Jeffrey Energy Center	2.70 E-03	2.70 E-03	2.60 E-03	2.50 E-03	2.40 E-03	2.40 E-03	2.00 E-03
8223_B_3	Springerville	2.70 E-03	2.70 E-03	2.30 E-03	2.10 E-03	1.90 E-03	1.70 E-03	7.00 E-04
1364_B_3	Mill Creek (KY)	2.60 E-03	2.60 E-03	2.60 E-03	2.60 E-03	2.60 E-03	2.60 E-03	2.20 E-03

Unique ID	Plant Name	Min Max	Min 99th	Min 90th	Min 85th	Min 80th	Min 75th	Min 50th
130_B_3	Cross	2.60 E-03	2.60 E-03	2.60 E-03	2.50 E-03	2.50 E-03	2.50 E-03	2.40 E-03
6190_B_2	Brame Energy Center	2.60 E-03	2.60 E-03	2.50 E-03	2.40 E-03	2.30 E-03	2.20 E-03	1.90 E-03
130_B_1	Cross	2.50 E-03	2.50 E-03	2.50 E-03	2.40 E-03	2.40 E-03	2.40 E-03	2.30 E-03
2727_B_4	Marshall (NC)	2.70 E-03	2.50 E-03	2.40 E-03	2.40 E-03	2.40 E-03	2.40 E-03	2.40 E-03
2240_B_8	Lon Wright	2.50 E-03	2.50 E-03	2.30 E-03	2.10 E-03	2.00 E-03	1.90 E-03	1.30 E-03
3149_B_2	TalenEnergy Montour	2.40 E-03	2.40 E-03	2.40 E-03	2.30 E-03	2.30 E-03	2.30 E-03	2.10 E-03
8042_B_1	Belews Creek	7.20 E-03	2.30 E-03	1.70 E-03	1.60 E-03	1.60 E-03	1.50 E-03	1.30 E-03
983_B_4, 983_B_5, 983_B_6	Clifty Creek	2.30 E-03	2.30 E-03	2.30 E-03	2.30 E-03	2.20 E-03	2.20 E-03	2.10 E-03
298_B_LIM1	Limestone	2.30 E-03	2.30 E-03	2.30 E-03	2.20 E-03	2.20 E-03	2.20 E-03	2.10 E-03
8222_B_B1	Coyote	2.30 E-03	2.30 E-03	2.20 E-03	2.20 E-03	2.20 E-03	2.20 E-03	2.00 E-03
6090_B_3	Sherburne County	2.30 E-03	2.30 E-03	2.20 E-03	2.20 E-03	2.20 E-03	2.20 E-03	2.00 E-03
3403_B_4	Gallatin (TN)	2.20 E-03	2.20 E-03	2.20 E-03	2.20 E-03	2.20 E-03	2.20 E-03	2.10 E-03
2277_B_2	Sheldon	2.20 E-03	2.20 E-03	2.10 E-03	2.10 E-03	2.10 E-03	2.10 E-03	2.10 E-03
3149_B_1	TalenEnergy Montour	2.20 E-03	2.10 E-03	1.90 E-03	1.70 E-03	1.60 E-03	1.40 E-03	6.60 E-04
7097_B_BLR1	J K Spruce	2.10 E-03	2.10 E-03	2.10 E-03	2.10 E-03	2.10 E-03	2.10 E-03	2.10 E-03
2079_B_5A	Hawthorn	2.10 E-03	2.10 E-03	2.00 E-03	2.00 E-03	1.90 E-03	1.90 E-03	1.70 E-03
56609_B_1	Dry Fork Station	2.10 E-03	2.10 E-03	2.00 E-03	1.90 E-03	1.90 E-03	1.80 E-03	1.50 E-03
2721_B_5	James E. Rogers Energy Complex	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03
1241_B_2	La Cygne	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	1.90 E-03
667_B_2	Northside Generating Station	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03
56224_B_BLR100	TS Power Plant	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03
703_B_4BLR	Bowen	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03

Unique ID	Plant Name	Min Max	Min 99th	Min 90th	Min 85th	Min 80th	Min 75th	Min 50th
56068_B_18	Elm Road Generating Station	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03
6041_B_1	H L Spurlock	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	1.80 E-03	1.00 E-03	1.00 E-03
8219_B_1	Ray D Nixon	2.80 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03
6030_B_2	Coal Creek	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03
6101_B_BW91	Wyodak	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03
6041_B_2	H L Spurlock	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03
6065_B_1	Iatan	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03
6257_B_2	Scherer	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03	2.00 E-03
2367_B_4	Schiller	2.00 E-03	2.00 E-03	1.90 E-03	1.90 E-03	1.80 E-03	1.80 E-03	1.60 E-03
7210_B_COP1	Cope	2.00 E-03	2.00 E-03	1.80 E-03	1.70 E-03	1.60 E-03	1.50 E-03	1.00 E-03
55479_B_3	Wygen 1	2.00 E-03	2.00 E-03	1.80 E-03	1.70 E-03	1.60 E-03	1.50 E-03	1.00 E-03
55749_B_PC1	Hardin Generator Project	2.00 E-03	2.00 E-03	1.80 E-03	1.70 E-03	1.60 E-03	1.50 E-03	1.00 E-03
963_B_41	Dallman	1.90 E-03	1.90 E-03	1.70 E-03	1.60 E-03	1.50 E-03	1.30 E-03	7.50 E-04
6095_B_2	Sooner	2.70 E-03	1.90 E-03	1.80 E-03	1.80 E-03	1.80 E-03	1.80 E-03	1.60 E-03
108_B_SGU1	Holcomb	1.90 E-03	1.90 E-03	1.80 E-03	1.80 E-03	1.70 E-03	1.60 E-03	1.40 E-03
2721_B_6	James E. Rogers Energy Complex	1.80 E-03	1.80 E-03	1.80 E-03	1.80 E-03	1.80 E-03	1.80 E-03	1.80 E-03
6204_B_1	Laramie River Station	1.80 E-03	1.80 E-03	1.80 E-03	1.70 E-03	1.70 E-03	1.70 E-03	1.60 E-03
2168_B_MB1	Thomas Hill	1.80 E-03	1.80 E-03	1.80 E-03	1.70 E-03	1.70 E-03	1.70 E-03	1.60 E-03
2876_B_1, 2876_B_2	Kyger Creek	1.80 E-03	1.80 E-03	1.70 E-03	1.70 E-03	1.70 E-03	1.70 E-03	1.60 E-03
7097_B_BLR2	J K Spruce	1.70 E-03	1.70 E-03	1.70 E-03	1.70 E-03	1.70 E-03	1.70 E-03	1.70 E-03
3935_B_3	John E Amos	1.70 E-03	1.70 E-03	1.60 E-03	1.50 E-03	1.50 E-03	1.40 E-03	1.20 E-03
6139_B_3	Welsh	1.70 E-03	1.70 E-03	1.60 E-03	1.50 E-03	1.50 E-03	1.40 E-03	1.20 E-03

Unique ID	Plant Name	Min Max	Min 99th	Min 90th	Min 85th	Min 80th	Min 75th	Min 50th
3403_B_3	Gallatin (TN)	1.60 E-03	1.60 E-03	1.60 E-03	1.60 E-03	1.60 E-03	1.60 E-03	1.50 E-03
3470_B_WAP8	W A Parish	1.50 E-03	1.50 E-03	1.50 E-03	1.50 E-03	1.40 E-03	1.40 E-03	8.70 E-04
2828_B_2	Cardinal	1.40 E-03	1.40 E-03	1.30 E-03	1.30 E-03	1.20 E-03	1.10 E-03	9.00 E-04
6139_B_1	Welsh	1.30 E-03	1.30 E-03	1.30 E-03	1.30 E-03	1.30 E-03	1.20 E-03	1.20 E-03
667_B_1	Northside Generating Station	1.20 E-03	1.20 E-03	1.20 E-03	1.20 E-03	1.20 E-03	1.10 E-03	4.70 E-04
8223_B_4	Springerville	1.20 E-03	1.20 E-03	1.10 E-03	1.10 E-03	1.10 E-03	1.10 E-03	9.50 E-04
2727_B_3	Marshall (NC)	1.10 E-03	1.10 E-03	1.10 E-03	1.10 E-03	1.10 E-03	1.10 E-03	1.00 E-03
6034_B_2	Belle River	2.00 E-03	1.10 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03
60_B_2	Whelan Energy Center	1.10 E-03	1.10 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03
4125_B_9	Manitowoc	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03
4078_B_4	Weston	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03	0.00 E+00
6248_B_1	Pawnee	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03
3935_B_2	John E Amos	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03
56068_B_19	Elm Road Generating Station	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03
165_B_2	GREC	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03	1.00 E-03
6195_B_2	John Twitty Energy Center	1.00 E-03	1.00 E-03	9.90 E-04	9.80 E-04	9.80 E-04	9.80 E-04	9.50 E-04
7343_B_4	George Neal South	1.00 E-03	1.00 E-03	9.60 E-04	9.40 E-04	9.20 E-04	9.00 E-04	8.00 E-04
3470_B_WAP5	W A Parish	1.00 E-03	1.00 E-03	9.60 E-04	9.40 E-04	9.20 E-04	9.00 E-04	5.10 E-04
56786_B_1	Spiritwood Station	9.00 E-04	9.00 E-04	8.60 E-04	8.40 E-04	8.20 E-04	8.00 E-04	7.00 E-04
6194_B_171B	Tolk	7.00 E-04	7.00 E-04	6.60 E-04	6.40 E-04	6.20 E-04	6.00 E-04	5.00 E-04
50835_B_1	TES Filer City Station	6.00 E-04	6.00 E-04	6.00 E-04	6.00 E-04	6.00 E-04	6.00 E-04	6.00 E-04

Unique ID	Plant Name	Min Max	Min 99th	Min 90th	Min 85th	Min 80th	Min 75th	Min 50th
50835_B_2	TES Filer City Station	6.00E-04	6.00E-04	5.80E-04	5.70E-04	5.60E-04	5.50E-04	5.00E-04
6138_B_1	Flint Creek	6.00E-04	5.90E-04	5.40E-04	5.10E-04	4.80E-04	4.50E-04	3.00E-04
6194_B_172B	Tolk	5.80E-04	5.80E-04	5.60E-04	5.40E-04	5.30E-04	5.20E-04	4.60E-04
6098_B_1	Big Stone	2.10E-04	2.10E-04	2.10E-04	2.10E-04	2.10E-04	2.10E-04	2.10E-04
3470_B_WAP6	W A Parish	2.00E-04	2.00E-04	1.80E-04	1.70E-04	1.60E-04	1.50E-04	1.00E-04
3470_B_WAP7	W A Parish	1.90E-04	1.90E-04	1.80E-04	1.70E-04	1.70E-04	1.60E-04	1.40E-04
4271_B_B1	John P Madgett	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
7213_B_1	Clover	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Appendix C

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
6076_B_4	1	Colstrip	Montana	No Retirement Listed	Subbituminous	740	Stack	WS	0.021	587.0
10343_B_SG-101	1	Foster Wheeler Mt Carmel Cogen	Pennsylvania	No Retirement Listed	Waste Coal	43	Stack	B	0.018	13.2
6076_B_3	1	Colstrip	Montana	No Retirement Listed	Subbituminous	740	Stack	WS	0.018	497.3
2103_B_2	1	Labadie	Missouri	2036	Subbituminous	593	PM CEMS - 30-day rolling average	ESPC	0.017	269.7
2103_B_1	1	Labadie	Missouri	2036	Subbituminous	593	PM CEMS - 30-day rolling average	ESPC	0.017	280.4
2103_B_4	1	Labadie	Missouri	2042	Subbituminous	593	PM CEMS - 30-day rolling average	ESPC	0.017	339.0
2103_B_3	1	Labadie	Missouri	2042	Subbituminous	593	PM CEMS - 30-	ESPC	0.017	367.8

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
							day rolling average			
976_B_123	1	Marion	Illinois	No Retirement Listed	Bituminous, Waste Coal	120	PM CEMS - 30-day rolling average	B	0.017	78.8
10113_B_CFB1, 10113_B_CFB2	2	John B Rich Memorial Power Station	Pennsylvania	No Retirement Listed	Waste Coal	80	PM CEMS - 30-day rolling average	B	0.015	30.9
6823_B_W1	1	D B Wilson	Kentucky	No Retirement Listed	Bituminous	417	PM CEMS - 30-day rolling average	ESPC	0.015	234.8
50611_B_031	1	Westwood Generation LLC	Pennsylvania	No Retirement Listed	Waste Coal	30	Stack	B	0.015	3.0
6146_B_1	1	Martin Lake	Texas	No Retirement Listed	Lignite, Subbituminous	800	PM CEMS - 30-day rolling average	ESPC	0.014	337.5
6041_B_3	1	H L Spurlock	Kentucky	No Retirement Listed	Bituminous	268	PM CEMS - 30-day rolling average	B	0.012	71.0

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
3954_B_3	1	Mt Storm	West Virginia	No Retirement Listed	Bituminous	520	PM CEMS - 30-day rolling average	ESPC + WS	0.012	112.3
6146_B_3	1	Martin Lake	Texas	No Retirement Listed	Lignite, Subbituminous	805	PM CEMS - 30-day rolling average	ESPC	0.012	284.9
1082_B_3	1	Walter Scott Jr Energy Center	Iowa	No Retirement Listed	Subbituminous	708	Stack	ESPC + B	0.011	265.4
3954_B_1, 3954_B_2	2	Mt Storm	West Virginia	No Retirement Listed	Bituminous	1109	PM CEMS - 30-day rolling average	ESPC + WS	0.011	138.1
1893_B_4	1	Clay Boswell	Minnesota	No Retirement Listed	Subbituminous	584	PM CEMS - 30-day rolling average	B	0.011	198.5
10143_B_ABB01	1	Colver Power Project	Pennsylvania	No Retirement Listed	Waste Coal	110	Stack	B	0.01	48.6
54634_B_1	1	St Nicholas Cogen Project	Pennsylv	No Retirement	Waste Coal	86	Stack	B	0.01	53.6

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
			ania	Listed						
8102_B_1	1	Gavin Power, LLC	Ohio	No Retirement Listed	Bituminous, Subbituminous	1348	Stack	ESPC	0.01	428.9
2823_B_B2	1	Milton R Young	North Dakota	No Retirement Listed	Lignite	447	PM CEMS - 30-day rolling average	ESPC	0.01	192.3
6018_B_2	1	East Bend	Kentucky	2041	Bituminous	600	PM CEMS - 30-day rolling average	ESPH	0.0099	142.9
6113_B_3	1	Gibson	Indiana	2034	Bituminous	630	PM CEMS - 30-day rolling average	ESPC	0.0098	112.6
6065_B_2	1	Iatan	Missouri	No Retirement Listed	Subbituminous	882	PM CEMS - 30-day rolling average	B	0.009	241.5
645_B_BB04	1	Big Bend	Florida	No Retirement Listed	Bituminous, Natural Gas	437	PM CEMS - 30-day rolling average	ESPC	0.009	73.7

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
6068_B_3	1	Jeffrey Energy Center	Kansas	2030	Subbituminous	728	Stack	ESPC	0.009	136.1
6177_B_U2B	1	Coronado	Arizona	2032	Subbituminous	382	PM CEMS - 30-day rolling average	ESPH	0.0086	65.3
6177_B_U1B	1	Coronado	Arizona	2032	Subbituminous	380	PM CEMS - 30-day rolling average	ESPH	0.0086	49.4
6183_B_SM-1	1	San Miguel	Texas	No Retirement Listed	Lignite	391	Stack	ESPC	0.0082	117.0
6705_B_4	1	Warrick	Indiana	No Retirement Listed	Bituminous	295	PM CEMS - 30-day rolling average	ESPC	0.0082	79.7
628_B_5	1	Crystal River	Florida	2034	Bituminous	710	PM CEMS - 30-day rolling average	ESPC	0.0081	166.2
628_B_4	1	Crystal River	Florida	2034	Bituminous	712	PM CEMS - 30-day rolling average	ESPC	0.0081	183.7

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
1356_B_2, 1356_B_3	2	Ghent	Kentucky	No Retirement Listed	Bituminous	980	PM CEMS - 30-day rolling average	ESPH + B	0.0081	104.8
6146_B_2	1	Martin Lake	Texas	No Retirement Listed	Lignite, Subbituminous	805	PM CEMS - 30-day rolling average	ESPC	0.008	162.1
6180_B_1	1	Oak Grove (TX)	Texas	No Retirement Listed	Lignite	855	PM CEMS - 30-day rolling average	B	0.008	242.0
6204_B_2	1	Laramie River Station	Wyoming	No Retirement Listed	Subbituminous	570	Stack	ESPH	0.008	170.0
136_B_2	1	Seminole (FL)	Florida	No Retirement Listed	Bituminous	657	Stack	ESPC	0.008	129.7
2364_B_1, 2364_B_2	2	Merrimack	New Hampshire	No Retirement Listed	Bituminous	438	Stack	ESPC	0.0079	3.3
1393_B_6	1	R S Nelson	Louisiana	No Retirement	Subbituminous, Petroleum Coke	550	PM CEMS - 30-day	ESPC	0.0079	89.2

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
				Listed			rolling average			
8066_B_BW73	1	Jim Bridger	Wyoming	2037	Subbituminous	523	Stack	ESPC	0.0078	129.4
8066_B_BW74	1	Jim Bridger	Wyoming	2037	Subbituminous	530	Stack	ESPC	0.0078	129.0
6664_B_101	1	Louisa	Iowa	No Retirement Listed	Subbituminous	746	Stack	ESPH + B	0.0073	133.9
7030_B_U2	1	Major Oak Power	Texas	No Retirement Listed	Lignite, Subbituminous	153	Stack	B	0.007	48.0
1733_B_2	1	Monroe (MI)	Michigan	2040	Bituminous, Subbituminous	773	PM CEMS - 30-day rolling average	ESPC	0.007	148.7
4078_B_3	1	Weston	Wisconsin	No Retirement Listed	Subbituminous	327	PM CEMS - 30-day rolling average	B	0.007	38.2
2817_B_1	1	Leland Olds	North Dakota	No Retirement Listed	Lignite, Subbituminous	222	Stack	ESPC	0.007	49.3

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
50974_B_UNIT 1	1	Scrubgrass Generating Plant	Pennsylvania	No Retirement Listed	Bituminous, Waste Coal	43	Stack	B + C	0.007	12.6
50974_B_UNIT 2	1	Scrubgrass Generating Plant	Pennsylvania	No Retirement Listed	Bituminous, Waste Coal	43	Stack	B + C	0.007	11.8
7030_B_U1	1	Major Oak Power	Texas	No Retirement Listed	Lignite, Subbituminous	152	Stack	B	0.007	49.9
6469_B_B1	1	Antelope Valley	North Dakota	No Retirement Listed	Lignite	450	Stack	B	0.007	106.1
7790_B_1-1	1	Bonanza	Utah	2030	Bituminous	458	Stack	B	0.007	139.6
8069_B_2	1	Huntington	Utah	2036	Bituminous	450	Stack	B	0.0069	76.8
8042_B_2	1	Belews Creek	North Carolina	2038	Bituminous	1110	PM CEMS - 30-day rolling average	ESPC	0.0069	131.3
60_B_1	1	Whelan Energy Center	Nebraska	No Retirement Listed	Subbituminous	77	Unknown	ESPC	0.0068	13.7

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
470_B_3	1	Comanche (CO)	Colorado	2040	Subbituminous	750	PM CEMS - 30-day rolling average	B	0.0068	151.1
6096_B_2	1	Nebraska City	Nebraska	No Retirement Listed	Subbituminous	691	Stack	B	0.0068	133.5
6009_B_2	1	White Bluff	Arkansas	2029	Subbituminous	819	PM CEMS - 30-day rolling average	ESPC	0.0064	117.3
56611_B_S01	1	Sandy Creek Energy Station	Texas	No Retirement Listed	Subbituminous	933	Stack	B	0.0062	197.8
6179_B_2	1	Fayette Power Project	Texas	No Retirement Listed	Subbituminous	590	PM CEMS - 30-day rolling average	ESPC	0.0061	133.7
1733_B_1	1	Monroe (MI)	Michigan	2040	Bituminous, Subbituminous	758	PM CEMS - 30-day rolling average	ESPC	0.0061	135.4
6113_B_1	1	Gibson	Indiana	2038	Bituminous	630	PM CEMS - 30-day	ESPC	0.006	80.3

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
							rolling average			
1356_B_4	1	Ghent	Kentucky	No Retirement Listed	Bituminous	465	PM CEMS - 30-day rolling average	ESPH + B	0.006	81.5
7213_B_2	1	Clover	Virginia	No Retirement Listed	Bituminous	437	PM CEMS - 30-day rolling average	B + WS	0.006	20.3
6180_B_2	1	Oak Grove (TX)	Texas	No Retirement Listed	Lignite	855	PM CEMS - 30-day rolling average	B	0.006	190.5
4162_B_1	1	Naughton	Wyoming	No Retirement Listed	Subbituminous	156	Stack	ESPC + C	0.006	41.3
6204_B_3	1	Laramie River Station	Wyoming	No Retirement Listed	Subbituminous	570	Stack	ESPH	0.006	128.2
50951_B_1	1	Sunnyside Cogen Associates	Utah	No Retirement Listed	Waste Coal	51	Stack	B	0.006	

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
6639_B_G1	1	R D Green	Kentucky	No Retirement Listed	Bituminous	231	Stack	ESPC	0.0059	41.4
56456_B_BLR1	1	Plum Point Energy Station	Arkansas	No Retirement Listed	Subbituminous	680	Stack	B	0.0058	113.3
2817_B_2	1	Leland Olds	North Dakota	No Retirement Listed	Lignite, Subbituminous	445	Stack	ESPC	0.0057	78.6
3140_B_1, 3140_B_2	2	Brunner Island	Pennsylvania	No Retirement Listed	Bituminous, Natural Gas	306 (Unit 1 only)	Stack	B	0.0057	19.7
2367_B_6	1	Schiller	New Hampshire	No Retirement Listed	Bituminous	48	Stack	ESPC	0.0057	1.1
1379_B_6, 1379_B_7, 1379_B_8, 1379_B_9	4	Shawnee	Kentucky	2034	Bituminous, Subbituminous	536	Stack	B + C	0.0056	25.1
56671_B_UHA01	1	Longview Power Plant	West Virginia	No Retirement Listed	Bituminous	700	PM CEMS - 30-day rolling average	B	0.0055	133.6

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
6068_B_2	1	Jeffrey Energy Center	Kansas	2039	Subbituminous	733	Stack	ESPC	0.0055	117.0
1379_B_1, 1379_B_2, 1379_B_3, 1379_B_4, 1379_B_5	5	Shawnee	Kentucky	2034	Bituminous, Subbituminous	670	Stack	B + C	0.0055	20.7
994_B_4	1	AES Petersburg	Indiana	No Retirement Listed	Bituminous	530	PM CEMS - 30-day rolling average	ESPC	0.0054	72.4
994_B_3	1	AES Petersburg	Indiana	No Retirement Listed	Bituminous	528	PM CEMS - 30-day rolling average	ESPC + B	0.0054	65.3
6641_B_1	1	Independence Steam Electric Station	Arkansas	2031	Subbituminous	809	PM CEMS - 30-day rolling average	ESPC	0.0054	83.4
6009_B_1	1	White Bluff	Arkansas	2029	Subbituminous	818	PM CEMS - 30-day rolling average	ESPC	0.0054	117.3
6179_B_1	1	Fayette Power Project	Texas	No Retirement Listed	Subbituminous	590	PM CEMS - 30-day rolling average	ESPC	0.0054	78.2

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
6002_B_3	1	James H Miller Jr	Alabama	No Retirement Listed	Subbituminous	687	Stack	ESPC + WS	0.0053	109.4
2828_B_3	1	Cardinal	Ohio	No Retirement Listed	Bituminous	620	Stack	ESPH	0.0052	87.4
6193_B_063B	1	Harrington	Texas	2041	Subbituminous	340	Stack	B	0.0052	45.5
6071_B_2	1	Trimble County	Kentucky	No Retirement Listed	Bituminous, Subbituminous	732	PM CEMS - 30-day rolling average	ESPC + B	0.0051	108.5
1356_B_1	1	Ghent	Kentucky	No Retirement Listed	Bituminous	474	PM CEMS - 30-day rolling average	ESPC + B	0.005	72.8
4162_B_2	1	Naughton	Wyoming	No Retirement Listed	Subbituminous	201	Stack	ESPC + C	0.005	40.9
1384_B_1, 1384_B_2	2	Cooper	Kentucky	No Retirement Listed	Bituminous	341	PM CEMS - 30-day rolling average	ESPC + B	0.005	1.3

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
6254_B_1	1	Ottumwa	Iowa	No Retirement Listed	Subbituminous	725	PM CEMS - 30-day rolling average	ESPH + B	0.005	106.4
2107_B_2	1	Sioux	Missouri	2029	Bituminous, Subbituminous	487	PM CEMS - 30-day rolling average	ESPC	0.005	38.9
2167_B_2	1	New Madrid	Missouri	No Retirement Listed	Subbituminous	575	Stack	ESPC	0.005	82.2
2167_B_1	1	New Madrid	Missouri	No Retirement Listed	Subbituminous	579	Stack	ESPC	0.005	80.5
6165_B_1	1	Hunter	Utah	2042	Bituminous	471	Stack	ESPC + B	0.005	62.8
6213_B_2SG1	1	Merom	Indiana	No Retirement Listed	Bituminous	492	Stack	ESPC	0.005	54.5
26_B_5	1	E C Gaston	Alabama	No Retirement Listed	Bituminous	832	Stack	ESPH + B + WS	0.0049	96.8

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
6761_B_101	1	Rawhide	Colorado	2030	Subbituminous	280	Stack	B	0.0049	52.8
2876_B_3, 2876_B_4, 2876_B_5	3	Kyger Creek	Ohio	No Retirement Listed	Bituminous, Subbituminous	576	PM CEMS - 30-day rolling average	ESPC	0.0048	27.8
1082_B_4	1	Walter Scott Jr Energy Center	Iowa	No Retirement Listed	Subbituminous	814	Stack	B	0.0048	88.5
6639_B_G2	1	R D Green	Kentucky	No Retirement Listed	Bituminous	223	Stack	ESPC	0.0048	33.1
6034_B_1	1	Belle River	Michigan	2029	Subbituminous	635	PM CEMS - 30-day rolling average	ESPC	0.0046	37.2
6096_B_1	1	Nebraska City	Nebraska	No Retirement Listed	Subbituminous	654	Stack	ESPC	0.0046	71.4
2291_B_5	1	North Omaha	Nebraska	No Retirement Listed	Subbituminous	216	Stack	ESPC	0.0046	31.2

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
10151_B_BLR1A, 10151_B_BLR1B	2	Grant Town Power Plant	West Virginia	No Retirement Listed	Waste Coal	80	Stack	B	0.0045	9.3
6113_B_2	1	Gibson	Indiana	2038	Bituminous	630	PM CEMS - 30-day rolling average	ESPC	0.0045	67.3
6113_B_4	1	Gibson	Indiana	2034	Bituminous	622	PM CEMS - 30-day rolling average	ESPC	0.0044	46.8
8223_B_2	1	Springerville	Arizona	2032	Subbituminous	406	Stack	B	0.0043	51.3
160_B_3	1	Apache Station	Arizona	No Retirement Listed	Bituminous, Subbituminous	175	Stack	ESPH	0.0042	22.6
6071_B_1	1	Trimble County	Kentucky	No Retirement Listed	Bituminous	511	PM CEMS - 30-day rolling average	ESPC + B	0.0042	62.2
6641_B_2	1	Independence Steam Electric Station	Arkansas	2031	Subbituminous	842	PM CEMS - 30-day rolling average	ESPC	0.0041	71.6

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
1091_B_3	1	George Neal North	Iowa	No Retirement Listed	Subbituminous	515	Stack	ESPC + B	0.0041	50.7
59_B_1	1	Platte	Nebraska	No Retirement Listed	Subbituminous	100	Stack	ESPH + B	0.0041	8.4
2823_B_B1	1	Milton R Young	North Dakota	No Retirement Listed	Lignite	237	PM CEMS - 30-day rolling average	ESPC	0.004	41.4
6021_B_C3	1	Craig (CO)	Colorado	2030	Subbituminous	448	Stack	B	0.004	59.5
8069_B_1	1	Huntington	Utah	2036	Bituminous	459	Stack	ESPC + B	0.004	55.8
6002_B_4	1	James H Miller Jr	Alabama	No Retirement Listed	Subbituminous	699	Stack	ESPC + WS	0.004	95.1
1733_B_3	1	Monroe (MI)	Michigan	2040	Bituminous, Subbituminous, Petroleum Coke	773	PM CEMS - 30-day rolling average	ESPC	0.004	62.4
6041_B_4	1	H L Spurlock	Kentucky	No Retirement	Bituminous	268	PM CEMS - 30-day	B	0.004	24.9

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
				Listed			rolling average			
6264_B_1	1	Mountaineer	West Virginia	2040	Bituminous	1299	Stack	ESPC	0.004	164.6
6213_B_1SG1	1	Merom	Indiana	No Retirement Listed	Bituminous	496	Stack	ESPC	0.004	55.0
6002_B_1	1	James H Miller Jr	Alabama	No Retirement Listed	Subbituminous	688	Stack	ESPC + WS	0.004	117.2
2442_B_4	1	Four Corners	New Mexico	2031	Subbituminous	770	Stack	B	0.004	101.0
6002_B_2	1	James H Miller Jr	Alabama	No Retirement Listed	Subbituminous	695	Stack	ESPC + WS	0.004	139.0
1040_B_1, 1040_B_2	2	Whitewater Valley	Indiana	No Retirement Listed	Bituminous	100	Stack	ESPC + B	0.004	0.3
4158_B_BW43	1	Dave Johnston	Wyoming	No Retirement	Subbituminous	220	Stack	B	0.004	28.4

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
				Listed						
3399_B_1	1	Cumberland (TN)	Tennessee	2029	Bituminous	1239	Stack	ESPC	0.0039	101.5
8102_B_2	1	Gavin Power, LLC	Ohio	No Retirement Listed	Bituminous, Subbituminous	1361	Stack	ESPC	0.0039	126.3
10603_B_031	1	Ebensburg Power	Pennsylvania	No Retirement Listed	Waste Coal	50	Stack	B	0.0039	7.7
3130_B_1, 3130_B_2	2	Seward (PA)	Pennsylvania	No Retirement Listed	Waste Coal	520	Stack	B	0.0038	24.6
6179_B_3	1	Fayette Power Project	Texas	No Retirement Listed	Subbituminous	435	PM CEMS - 30-day rolling average	ESPC	0.0038	66.6
6077_B_2	1	Gerald Gentleman	Nebraska	No Retirement Listed	Subbituminous	700	Stack	B	0.0038	76.0
55076_B_AA001, 55076_B_AA002	2	Red Hills Generati	Mississippi	No Retirement	Lignite	440	Stack	B	0.0037	28.7

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
		ng Facility		Listed						
10671_B_1A, 10671_B_1B, 10671_B_2A, 10671_B_2B	4	River Valley	Oklahoma	No Retirement Listed	Bituminous, Subbituminous	320	Stack	B	0.0037	4.1
2277_B_1	1	Sheldon	Nebraska	No Retirement Listed	Subbituminous	104	Stack	B	0.0036	7.8
1167_B_9	1	Muscatine Plant #1	Iowa	No Retirement Listed	Subbituminous	163	Stack	ESPC	0.0036	13.1
50888_B_BLR1	1	Northampton Generating Company LP	Pennsylvania	No Retirement Listed	Waste Coal	112	Stack	B	0.0036	4.8
1364_B_4	1	Mill Creek (KY)	Kentucky	No Retirement Listed	Bituminous	477	PM CEMS - 30-day rolling average	ESPC + B	0.0035	52.3
3948_B_1	1	Mitchell (WV)	West Virginia	2040	Bituminous	770	Stack	ESPC	0.0035	46.6

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
3935_B_1	1	John E Amos	West Virginia	2040	Bituminous	800	Stack	ESPC	0.0035	70.1
6469_B_B2	1	Antelope Valley	North Dakota	No Retirement Listed	Lignite	450	Stack	B	0.0034	63.8
6166_B_MB1, 6166_B_MB2	2	Rockport	Indiana	2029	Bituminous, Subbituminous	2600	Stack	ESPC	0.0034	67.6
983_B_1, 983_B_2, 983_B_3	3	Clifty Creek	Indiana	No Retirement Listed	Bituminous, Subbituminous	588	PM CEMS - 30-day rolling average	ESPC	0.0032	16.8
3403_B_2	1	Gallatin (TN)	Tennessee	2032	Bituminous, Subbituminous	225	Stack	ESPC + B	0.0031	18.4
2168_B_MB2	1	Thomas Hill	Missouri	No Retirement Listed	Subbituminous	270	Stack	ESPC	0.003	26.3
10678_B_BLR1	1	AES Warrior Run Cogeneration Facility	Maryland	No Retirement Listed	Bituminous, Waste Coal	180	Stack	B	0.003	20.4
2168_B_MB3	1	Thomas Hill	Missouri	No Retirem	Subbituminous	699	Stack	ESPC	0.003	79.1

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
				ent Listed						
1733_B_4	1	Monroe (MI)	Michigan	2040	Bituminous, Subbituminous, Petroleum Coke	762	PM CEMS - 30-day rolling average	ESPC	0.003	59.6
6165_B_3	1	Hunter	Utah	2042	Bituminous	460	Stack	B + WS	0.003	48.5
2107_B_1	1	Sioux	Missouri	2029	Bituminous, Subbituminous	487	PM CEMS - 30-day rolling average	ESPC	0.003	39.6
703_B_3BLR	1	Bowen	Georgia	2035	Bituminous	892	Stack	ESPC + B + WS	0.003	30.6
6064_B_N1	1	Nearman Creek	Kansas	No Retirement Listed	Subbituminous	240	PM CEMS - 30-day rolling average	ESPC + B	0.003	20.1
3403_B_1	1	Gallatin (TN)	Tennessee	2032	Bituminous, Subbituminous	225	Stack	ESPC + B	0.003	19.0
4158_B_BW41	1	Dave Johnston	Wyoming	No Retirement Listed	Subbituminous	105	Stack	ESPC	0.003	12.3
6030_B_1	1	Coal Creek	North	No Reti	Lignite	574	Stack	ESPC	0.003	72.8

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
			Dakota	rement Listed						
4158_B_BW42	1	Dave Johnston	Wyoming	No Retirement Listed	Subbituminous	105	Stack	ESPC	0.003	13.1
56596_B_1	1	Wygen III	Wyoming	No Retirement Listed	Subbituminous	100	Stack	B	0.003	13.4
6165_B_2	1	Hunter	Utah	2042	Bituminous	430	Stack	B	0.003	44.5
10743_B_CFB1, 10743_B_CFB2	2	Morgantown Energy Facility	West Virginia	No Retirement Listed	Bituminous, Waste Coal	50	Stack	B	0.003	4.7
56319_B_1	1	Wygen 2	Wyoming	2048	Subbituminous	90	Stack	B	0.003	13.4
2828_B_1	1	Cardinal	Ohio	2030	Bituminous	585	Stack	ESPC	0.003	60.0
6768_B_1	1	Sikeston Power Station	Missouri	No Retirement Listed	Subbituminous	240	PM CEMS - 30-day rolling average	ESPC	0.0029	23.6
130_B_4	1	Cross	South Carolina	No Retirement	Bituminous	600	Stack	ESPC + WS	0.0029	45.2

Unique ID	Number of Units	Plant Name	State	Retirement Year Listed	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
2442_B_5	1	Four Corners	New Mexico	2031	Subbituminous	770	Stack	B	0.0029	63.4
6772_B_1	1	Hugo	Oklahoma	No Retirement Listed	Subbituminous	440	Stack	ESPC	0.0029	43.9
298_B_LIM2	1	Limestone	Texas	2029	Lignite, Subbituminous	858	Stack	ESPC	0.0029	78.4
50776_B_BLR1, 50776_B_BLR2	2	Panther Creek Energy Facility	Pennsylvania	No Retirement Listed	Waste Coal	84	Stack	B	0.0028	0.8
6195_B_1	1	John Twitty Energy Center	Missouri	No Retirement Listed	Subbituminous	184	Stack	B	0.0028	13.5
6077_B_1	1	Gerald Gentleman	Nebraska	No Retirement Listed	Subbituminous	665	Stack	B	0.0028	53.6
3948_B_2	1	Mitchell (WV)	West Virginia	2040	Bituminous	790	Stack	ESPC	0.0027	62.3

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
6068_B_1	1	Jeffrey Energy Center	Kansas	2039	Subbituminous	728	Stack	ESPC	0.0027	48.1
8223_B_3	1	Springerville	Arizona	No Retirement Listed	Subbituminous	417	Stack	B	0.0027	34.7
1364_B_3	1	Mill Creek (KY)	Kentucky	No Retirement Listed	Bituminous	391	PM CEMS - 30-day rolling average	ESPC + B	0.0026	24.9
130_B_3	1	Cross	South Carolina	No Retirement Listed	Bituminous	600	Stack	ESPC + WS	0.0026	44.5
6190_B_2	1	Brame Energy Center	Louisiana	No Retirement Listed	Subbituminous	493	Stack	ESPH + B	0.0026	32.4
130_B_1	1	Cross	South Carolina	No Retirement Listed	Bituminous	580	PM CEMS - 30-day rolling average	ESPC + WS	0.0025	29.9
2727_B_4	1	Marshall (NC)	North Carolina	2034	Bituminous	660	PM CEMS - 30-day rolling average	ESPC	0.0025	41.3

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
2240_B_8	1	Lon Wright	Nebraska	No Retirement Listed	Subbituminous	82	Stack	ESPH + B	0.0025	5.1
3149_B_2	1	TalenEnergy Montour	Pennsylvania	No Retirement Listed	Bituminous	752	Stack	ESPC	0.0024	8.3
8042_B_1	1	Belews Creek	North Carolina	2038	Bituminous	1110	PM CEMS - 30-day rolling average	ESPC	0.0023	48.1
983_B_4, 983_B_5, 983_B_6	3	Clifty Creek	Indiana	No Retirement Listed	Bituminous, Subbituminous	588	PM CEMS - 30-day rolling average	ESPC	0.0023	12.8
298_B_LIM1	1	Limestone	Texas	2029	Lignite, Subbituminous	831	Stack	ESPC	0.0023	49.8
8222_B_B1	1	Coyote	North Dakota	No Retirement Listed	Lignite	429	Stack	B	0.0023	26.7
6090_B_3	1	Sherburne County	Minnesota	2030	Subbituminous	876	Stack	B	0.0023	44.2
3403_B_4	1	Gallatin (TN)	Tenne	2032	Bituminous,	263	Stack	ESPC + B	0.0022	17.1

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
			ssee		Subbituminous					
2277_B_2	1	Sheldon	Nebraska	No Retirement Listed	Subbituminous	115	Stack	B	0.0022	5.7
3149_B_1	1	TalenEnergy Montour	Pennsylvania	No Retirement Listed	Bituminous	752	Stack	ESPC	0.0021	14.9
7097_B_BLR1	1	J K Spruce	Texas	No Retirement Listed	Subbituminous	560	Unknown	B	0.0021	25.6
2079_B_5A	1	Hawthorn	Missouri	No Retirement Listed	Subbituminous	564	Stack	B	0.0021	31.4
56609_B_1	1	Dry Fork Station	Wyoming	No Retirement Listed	Subbituminous	380	Stack	B	0.0021	29.9
2721_B_5	1	James E. Rogers Energy Complex	North Carolina	No Retirement Listed	Bituminous, Natural Gas	544	PM CEMS - 30-day rolling average	ESPC	0.002	18.7

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
1241_B_2	1	La Cygne	Kansas	2039	Bituminous, Subbituminous	662	PM CEMS - 30-day rolling average	B	0.002	33.8
667_B_2	1	Northside Generating Station	Florida	No Retirement Listed	Bituminous, Petroleum Coke	293	Stack	B	0.002	7.4
56224_B_BLR100	1	TS Power Plant	Nevada	No Retirement Listed	Subbituminous	218	Stack	B	0.002	11.3
703_B_4BLR	1	Bowen	Georgia	2035	Bituminous	892	Stack	ESPC + B + WS	0.002	36.2
56068_B_18	1	Elm Road Generating Station	Wisconsin	No Retirement Listed	Bituminous, Subbituminous	633	PM CEMS - 30-day rolling average	WESP + B	0.002	40.4
6041_B_1	1	H L Spurlock	Kentucky	No Retirement Listed	Bituminous	300	PM CEMS - 30-day rolling average	ESPC + WESP	0.002	13.6
8219_B_1	1	Ray D Nixon	Colorado	2029	Bituminous, Subbituminous	208	Stack	B	0.002	12.0

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
6030_B_2	1	Coal Creek	North Dakota	No Retirement Listed	Lignite	573	Stack	ESPC	0.002	38.4
6101_B_BW91	1	Wyodak	Wyoming	2039	Subbituminous	332	Stack	B	0.002	23.4
6041_B_2	1	H L Spurlock	Kentucky	No Retirement Listed	Bituminous	510	PM CEMS - 30-day rolling average	ESPH + WESP	0.002	23.3
6065_B_1	1	Iatan	Missouri	2039	Subbituminous	700	PM CEMS - 30-day rolling average	B	0.002	25.2
6257_B_2	1	Scherer	Georgia	No Retirement Listed	Subbituminous	860	Stack	ESPH + B + WS	0.002	43.6
2367_B_4	1	Schiller	New Hampshire	No Retirement Listed	Bituminous	48	Stack	ESPC	0.002	0.4
7210_B_COP1	1	Cope	South Carolina	No Retirement Listed	Bituminous	415	Stack	B	0.002	18.0

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
55479_B_3	1	Wygen 1	Wyoming	No Retirement Listed	Subbituminous	85	Stack	B	0.002	8.5
55749_B_PC1	1	Hardin Generator Project	Montana	No Retirement Listed	Subbituminous	107	Stack	B	0.002	2.2
963_B_41	1	Dallman	Illinois	No Retirement Listed	Bituminous	208	Stack	B	0.0019	10.1
6095_B_2	1	Sooner	Oklahoma	2045	Subbituminous	520	Stack	ESPC	0.0019	18.0
108_B_SGU1	1	Holcomb	Kansas	No Retirement Listed	Subbituminous	359	Stack	B	0.0019	10.8
2721_B_6	1	James E. Rogers Energy Complex	North Carolina	2048	Bituminous, Natural Gas	844	PM CEMS - 30-day rolling average	B	0.0018	37.8
6204_B_1	1	Laramie River Station	Wyoming	No Retirement Listed	Subbituminous	570	Stack	ESPH	0.0018	26.5

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
2168_B_MB1	1	Thomas Hill	Missouri	No Retirement Listed	Subbituminous	165	Stack	ESPC	0.0018	11.0
2876_B_1, 2876_B_2	2	Kyger Creek	Ohio	No Retirement Listed	Bituminous, Subbituminous	386	PM CEMS - 30-day rolling average	ESPC	0.0018	10.1
7097_B_BLR2	1	J K Spruce	Texas	No Retirement Listed	Subbituminous	785	Unknown	B	0.0017	41.2
3935_B_3	1	John E Amos	West Virginia	2040	Bituminous	1300	Stack	ESPC	0.0017	54.5
6139_B_3	1	Welsh	Texas	2038	Subbituminous	528	Stack	ESPH + B	0.0017	22.0
3403_B_3	1	Gallatin (TN)	Tennessee	2032	Bituminous, Subbituminous	263	Stack	ESPC + B	0.0016	9.0
3470_B_WAP8	1	W A Parish	Texas	No Retirement Listed	Subbituminous	610	Stack	B	0.0015	33.2
2828_B_2	1	Cardinal	Ohio	No Retirement	Bituminous	585	Stack	ESPC	0.0014	22.7

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
				Listed						
6139_B_1	1	Welsh	Texas	2038	Subbituminous	528	Stack	ESPH + B	0.0013	23.1
667_B_1	1	Northside Generating Station	Florida	No Retirement Listed	Bituminous, Petroleum Coke	293	Stack	B	0.0012	13.0
8223_B_4	1	Springerville	Arizona	No Retirement Listed	Subbituminous	415	Stack	B	0.0012	10.0
2727_B_3	1	Marshall (NC)	North Carolina	2034	Bituminous	658	PM CEMS - 30-day rolling average	ESPC	0.0011	13.4
6034_B_2	1	Belle River	Michigan	2029	Subbituminous	635	PM CEMS - 30-day rolling average	ESPC	0.0011	22.9
60_B_2	1	Whelan Energy Center	Nebraska	No Retirement Listed	Subbituminous	232	PM CEMS - 30-day rolling average	B	0.0011	6.7
4125_B_9	1	Manitowoc	Wisconsin	No Retirement	Bituminous, Subbituminous,	58	PM CEMS - 30-day	B + C	0.001	0.9

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
				Listed	Petroleum Coke		rolling average			
4078_B_4	1	Weston	Wisconsin	No Retirement Listed	Subbituminous	550	PM CEMS - 30-day rolling average	B	0.001	15.2
6248_B_1	1	Pawnee	Colorado	No Retirement Listed	Subbituminous	505	Stack	B	0.001	14.7
3935_B_2	1	John E Amos	West Virginia	2040	Bituminous	800	Stack	ESPC	0.001	19.7
56068_B_19	1	Elm Road Generating Station	Wisconsin	No Retirement Listed	Bituminous, Subbituminous	633	PM CEMS - 30-day rolling average	WESP + B	0.001	19.6
165_B_2	1	GREC	Oklahoma	No Retirement Listed	Subbituminous	492	Unknown	B	0.001	0.8
6195_B_2	1	John Twitty Energy Center	Missouri	No Retirement Listed	Subbituminous	275	Stack	B	0.001	5.6
7343_B_4	1	George Neal South	Iowa	No Retirem	Subbituminous	645	Stack	ESPC + B	0.001	12.2

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
				ent Listed						
3470_B_WAP5	1	W A Parish	Texas	No Retirement Listed	Subbituminous	659	Stack	B	0.001	14.6
56786_B_1	1	Spiritwood Station	North Dakota	No Retirement Listed	Lignite	92	Stack	B	0.0009	2.5
6194_B_171B	1	Tolk	Texas	2032	Subbituminous	532	Stack	B	0.0007	4.2
50835_B_1	1	TES Filer City Station	Michigan	No Retirement Listed	Bituminous	30	Stack	B	0.0006	0.9
50835_B_2	1	TES Filer City Station	Michigan	No Retirement Listed	Bituminous	30	Stack	B	0.0006	1.0
6138_B_1	1	Flint Creek	Arkansas	2038	Subbituminous	528	Stack	ESPH + B	0.00059	7.6
6194_B_172B	1	Tolk	Texas	2032	Subbituminous	535	Stack	B	0.00058	5.4
6098_B_1	1	Big Stone	South Dakota	No Retirement Listed	Subbituminous	474	Stack	B	0.00021	2.5

Unique ID	Number of Units	Plant Name	State	Retirement Year	Modeled Fuel	Capacity (MW)	Compliance	PM Control	Min 99th Rounded	99th PM Emissions (tons)
3470_B_WAP6	1	W A Parish	Texas	No Retirement Listed	Subbituminous	653	Stack	B	0.0002	3.8
3470_B_WAP7	1	W A Parish	Texas	No Retirement Listed	Subbituminous	577	Stack	B	0.00019	3.2
4271_B_B1	1	John P Madgett	Wisconsin	No Retirement Listed	Subbituminous	390	PM CEMS - 30-day rolling average	ESPH + B	0.000	0.0
7213_B_1	1	Clover	Virginia	2045	Bituminous	440	PM CEMS - 30-day rolling average	B + WS	0.000	0

Appendix D

Plant Details				0.015 lb/MMBtu			0.010 lb/MMBtu			0.006 lb/MMBtu	
Unique ID_Final	**Plant Name**	**PM Control**	**Baseline fPM Emissions (tons/year)**	**fPM Emission Reductions (tons/year)**	**Annualized Cost-Low Estimate ($/year)**	**Annualized Cost-High Estimate ($/year)**	**fPM Emission Reductions (tons/year)**	**Annualized Cost-Low Estimate ($/year)**	**Annualized Cost-High Estimate ($/year)**	**fPM Emission Reductions (tons/year)**	**Annualized Cost ($/year)**
6076_B_4	Colstrip	WS	587.0	166.6	843600		528.3	19058306		528.3	19058306
10343_B_SG-101	Foster Wheeler Mt Carmel Cogen	B	13.2	8.8	37954		8.8	37954		8.8	37954
6076_B_3	Colstrip	WS	497.3	82.3	843600		442.1	18992866		442.1	18992866
2103_B_2	Labadie	ESPC	269.7	33.2	3228885	4663945	112.5	5381475	7175300	238.0	14852871
2103_B_1	Labadie	ESPC	280.4	34.5	3228885	4663945	116.9	5381475	7175300	247.4	14852871
2103_B_4	Labadie	ESPC	339.0	41.7	2828610	4085770	141.4	4714350	6285800	299.1	13011606
2103_B_3	Labadie	ESPC	367.8	45.2	2828610	4085770	153.4	4714350	6285800	324.5	13011606
976_B_123	Marion	B	78.8	51.0	42026		51.0	42026		51.0	42026
10113_B_CFB1, 10113_B_CFB2	John B Rich Memorial Power Station	B	30.9				18.5	24077		18.5	24077

Plant Details				0.015 lb/MMBtu			0.010 lb/MMBtu			0.006 lb/MMBtu	
Unique ID_Final	**Plant Name**	**PM Control**	**Baseline fPM Emissions (tons/year)**	**fPM Emission Reductions (tons/year)**	**Annualized Cost-Low Estimate ($/year)**	**Annualized Cost-High Estimate ($/year)**	**fPM Emission Reductions (tons/year)**	**Annualized Cost-Low Estimate ($/year)**	**Annualized Cost-High Estimate ($/year)**	**fPM Emission Reductions (tons/year)**	**Annualized Cost ($/year)**
6823_B_W1	D B Wilson	ESPC	234.8				78.3	3565350	4753800	203.5	11118238
50611_B_031	Westwood Generation LLC	B	3.0				1.8	14840		1.8	14840
6146_B_1	Martin Lake	ESPC	337.5				96.4	6840000	9120000	289.3	23065501
6041_B_3	H L Spurlock	B	71.0				35.5	188376		35.5	188376
3954_B_3	Mt Storm	ESPC + WS	112.3				18.7	2667600	3853200	93.6	12541047
6146_B_3	Martin Lake	ESPC	284.9				47.5	4129650	5965050	237.4	23091952
1082_B_3	Walter Scott Jr Energy Center	ESPC + B	265.4				120.7	471090		120.7	471090
3954_B_1, 3954_B_2	Mt Storm	ESPC + WS	138.1				12.6	758556	3413502	113.0	25882051

Plant Details				0.015 lb/MMBtu			0.010 lb/MMBtu			0.006 lb/MMBtu	
Unique ID_Final	**Plant Name**	**PM Control**	**Baseline fPM Emissions (tons/year)**	**fPM Emission Reductions (tons/year)**	**Annualized Cost-Low Estimate ($/year)**	**Annualized Cost-High Estimate ($/year)**	**fPM Emission Reductions (tons/year)**	**Annualized Cost-Low Estimate ($/year)**	**Annualized Cost-High Estimate ($/year)**	**fPM Emission Reductions (tons/year)**	**Annualized Cost ($/year)**
1893_B_4	Clay Boswell	B	198.5				90.2	296552		90.2	296552
10143_B_ABB01	Colver Power Project	B	48.6							19.4	60221
54634_B_1	St Nicholas Cogen Project	B	53.6							21.4	69525
8102_B_1	Gavin Power, LLC	ESPC	428.9							343.1	28714416
2823_B_B2	Milton R Young	ESPC	192.3							153.8	14429784
6018_B_2	East Bend	ESPH	142.9							114.0	12592800
6113_B_3	Gibson	ESPC	112.6							89.6	29360520
6065_B_2	Iatan	B	241.5							80.5	470496
645_B_BB04	Big Bend	ESPC	73.7							57.4	11298116
6068_B_3	Jeffrey	ESPC	136.1							105.8	31643248

Plant Details				0.015 lb/MMBtu			0.010 lb/MMBtu			0.006 lb/MMBtu	
Unique ID_Final	**Plant Name**	**PM Control**	**Baseline fPM Emissions (tons/year)**	**fPM Emission Reductions (tons/year)**	**Annualized Cost-Low Estimate ($/year)**	**Annualized Cost-High Estimate ($/year)**	**fPM Emission Reductions (tons/year)**	**Annualized Cost-Low Estimate ($/year)**	**Annualized Cost-High Estimate ($/year)**	**fPM Emission Reductions (tons/year)**	**Annualized Cost ($/year)**
	Energy Center										
6177_B_U2B	Coronado	ESPH	65.3							50.1	14321180
6177_B_U1B	Coronado	ESPH	49.4							37.9	14184260
6183_B_SM-1	San Miguel	ESPC	117.0							88.5	13670942
6705_B_4	Warrick	ESPC	79.7							60.2	8631293
628_B_5	Crystal River	ESPC	166.2							125.1	18158960
628_B_4	Crystal River	ESPC	183.7							138.3	18309080
1356_B_2, 1356_B_3	Ghent	ESPH + B	104.8							27.2	470941
6146_B_2	Martin Lake	ESPC	162.1							121.5	22745693
6180_B_1	Oak Grove (TX)	B	242.0							60.5	527500
6204_B_2	Laramie Rive	ESPH	170.0							127.5	14614122

Plant Details				0.015 lb/MMBtu			0.010 lb/MMBtu			0.006 lb/MMBtu	
Unique ID_Final	Plant Name	PM Control	Baseline fPM Emissions (tons/year)	fPM Emission Reductions (tons/year)	Annualized Cost-Low Estimate ($/year)	Annualized Cost-High Estimate ($/year)	fPM Emission Reductions (tons/year)	Annualized Cost-Low Estimate ($/year)	Annualized Cost-High Estimate ($/year)	fPM Emission Reductions (tons/year)	Annualized Cost ($/year)
	r Station										
136_B_2	Seminole (FL)	ESPC	129.7							97.3	15062016
2364_B_1, 2364_B_2	Merrimack	ESPC	3.3							2.4	13168855
1393_B_6	R S Nelson	ESPC	89.2							66.6	15608736
8066_B_BW73	Jim Bridger	ESPC	129.4							96.2	12699486
8066_B_BW74	Jim Bridger	ESPC	129.0							95.9	12809040
6664_B_101	Louisa	ESPH + B	133.9							23.8	400485
7030_B_U2	Major Oak Power	B	48.0							6.9	105684
1733_B_2	Monroe (MI)	ESPC	148.7							106.2	15895972
4078_B_3	Weston	B	38.2							5.5	208448
2817_B_1	Leland Olds	ESPC	49.3							35.2	8203024

Plant Details				0.015 lb/MMBtu			0.010 lb/MMBtu			0.006 lb/MMBtu	
Unique ID_Final	**Plant Name**	**PM Control**	**Baseline fPM Emissions (tons/year)**	**fPM Emission Reductions (tons/year)**	**Annualized Cost-Low Estimate ($/year)**	**Annualized Cost-High Estimate ($/year)**	**fPM Emission Reductions (tons/year)**	**Annualized Cost-Low Estimate ($/year)**	**Annualized Cost-High Estimate ($/year)**	**fPM Emission Reductions (tons/year)**	**Annualized Cost ($/year)**
50974_B_UNIT 1	Scrubgrass Generating Plant	B + C	12.6							1.8	32632
50974_B_UNIT 2	Scrubgrass Generating Plant	B + C	11.8							1.7	32634
7030_B_U1	Major Oak Power	B	49.9							7.1	105684
6469_B_B1	Antelope Valley	B	106.1							15.2	306534
7790_B_1-1	Bonanza	B	139.6							19.9	299353
8069_B_2	Huntington	B	76.8							10.0	258387
8042_B_2	Belews Creek	ESPC	131.3							93.2	18511470
60_B_1	Whelan Ener	ESPC	13.7							9.6	3351478

Plant Details				0.015 lb/MMBtu			0.010 lb/MMBtu			0.006 lb/MMBtu	
Unique ID_Final	Plant Name	PM Control	Baseline fPM Emissions (tons/year)	fPM Emission Reductions (tons/year)	Annualized Cost-Low Estimate ($/year)	Annualized Cost-High Estimate ($/year)	fPM Emission Reductions (tons/year)	Annualized Cost-Low Estimate ($/year)	Annualized Cost-High Estimate ($/year)	fPM Emission Reductions (tons/year)	Annualized Cost ($/year)
	gy Center										
470_B_3	Comanche (CO)	B	151.1							17.8	434070
6096_B_2	Nebraska City	B	133.5							15.7	333738
6009_B_2	White Bluff	ESPC	117.3							80.6	38368512
56611_B_S01	Sandy Creek Energy Station	B	197.8							9.6	452490
6179_B_2	Fayette Power Project	ESPC	133.7							89.9	15472621
1733_B_1	Monroe (MI)	ESPC	135.4							91.0	15587512
TOTAL			9189.0	463.2	13882170	17499430	1630.9	77278893	54027752	6163.4	63253787