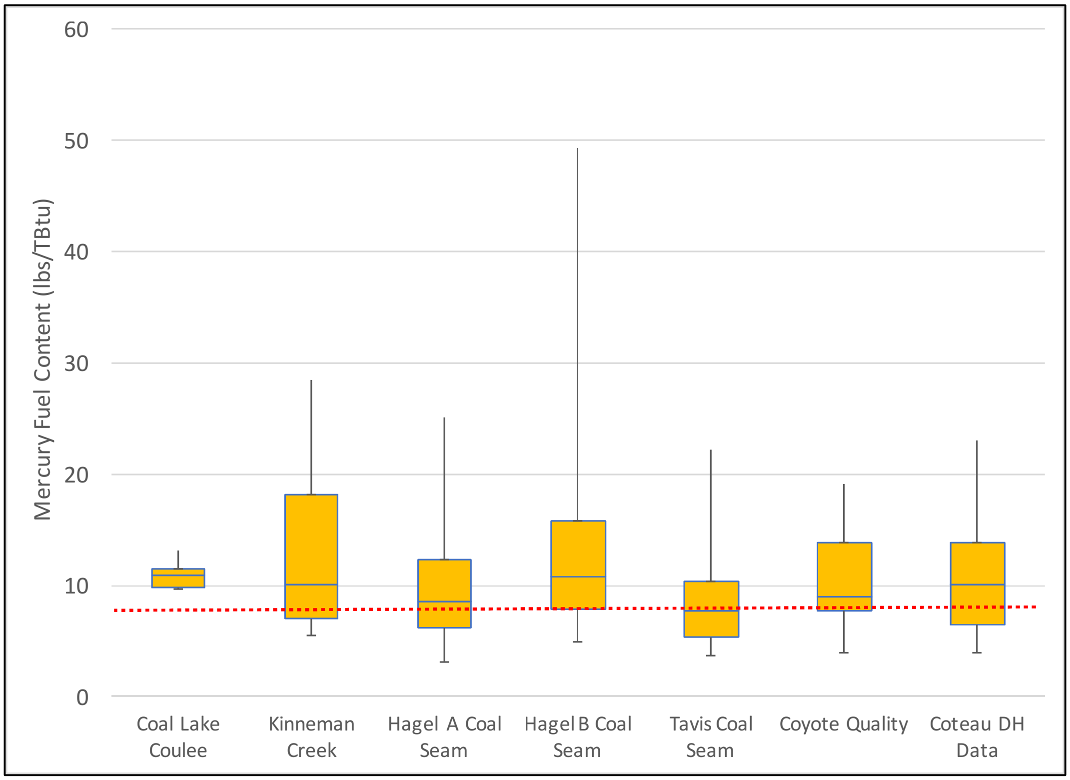

Figure 6-1. Mercury Content Variability for Eight North Dakota Lignite Mines

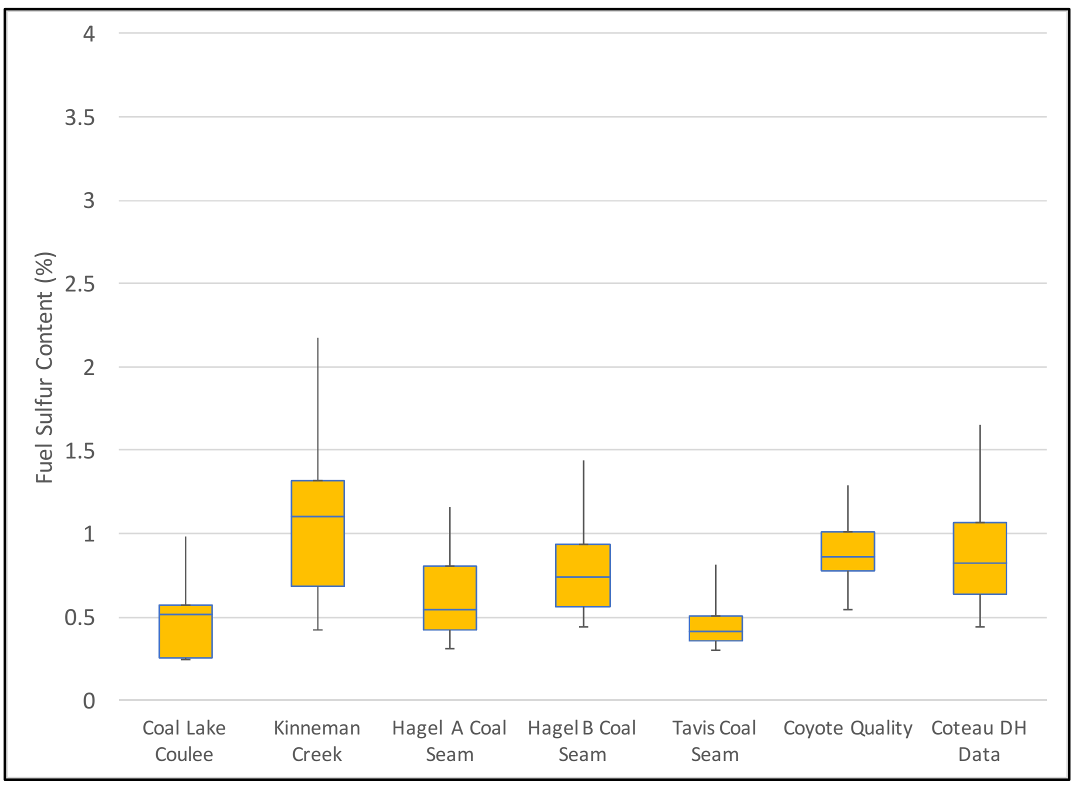

Figure 6-2. Fuel Sulfur Content Variability for Eight North Dakota Lignite Mines

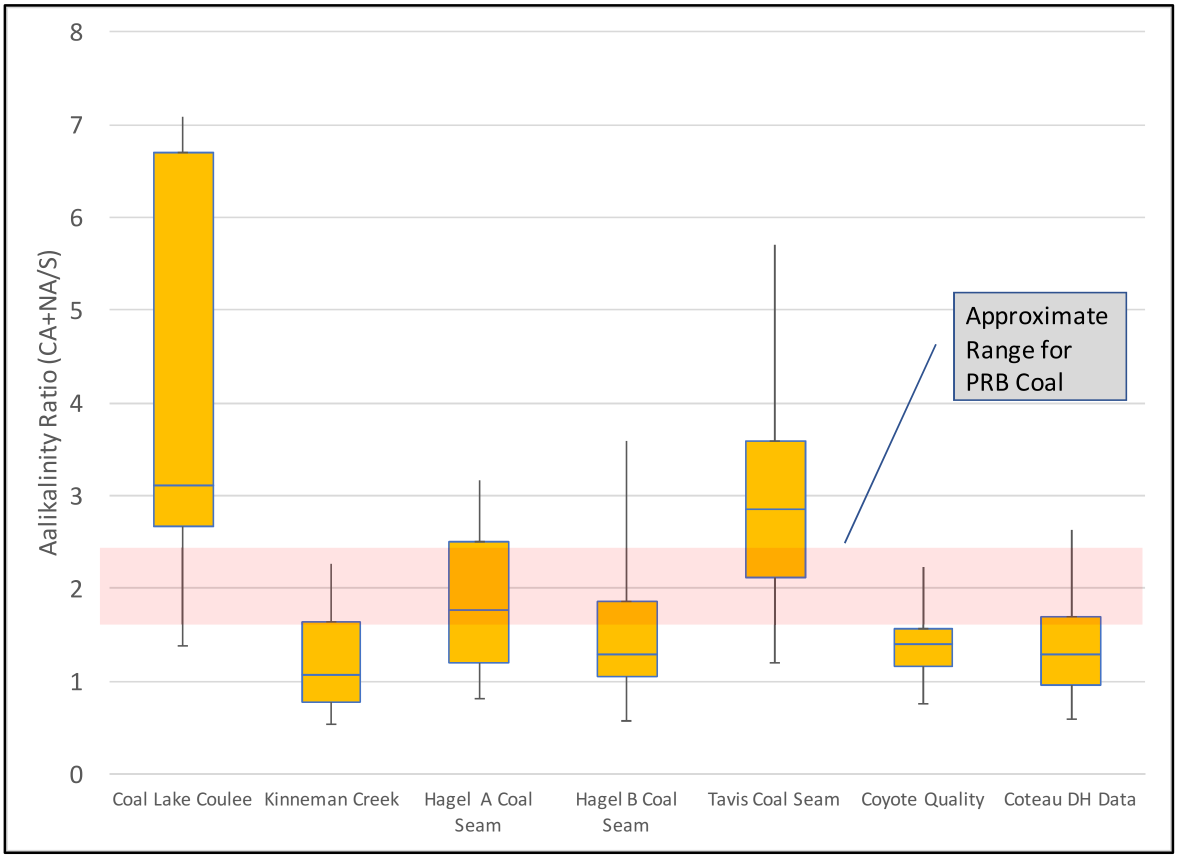

Figure 6-3. Fuel Alkalinity/Sulfur Ratio for Eight North Dakota Mines

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

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

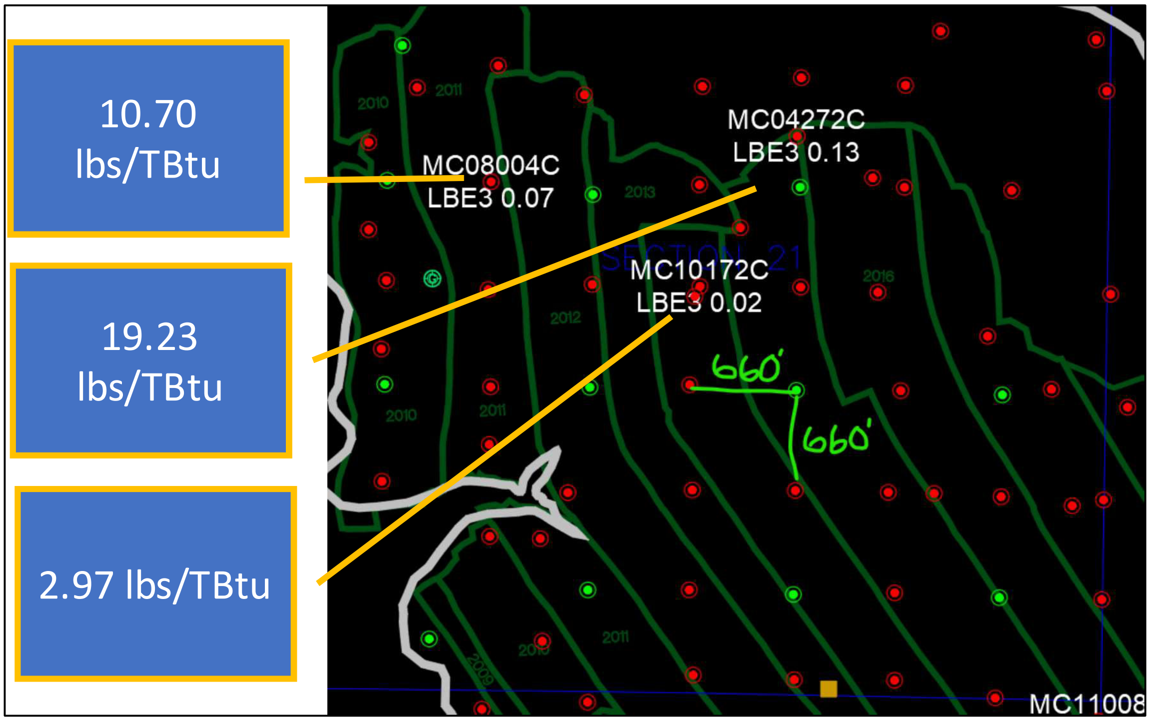

Figure 6-4. Spatial Variation of Hg in a Lignite Mine

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

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

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

6.2 Texas Gulf Coast Mines and Generating Units

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

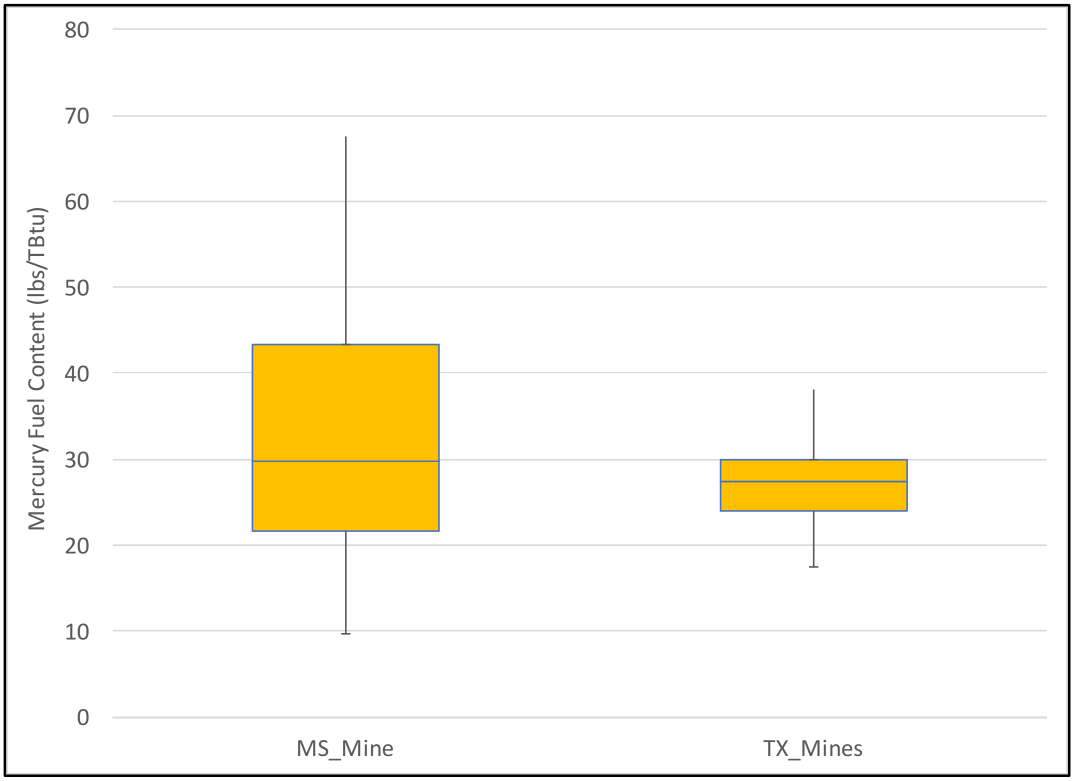

Figure 6-5. Mercury Variability for Two Gulf Coast Sources: Mississippi, Texas

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

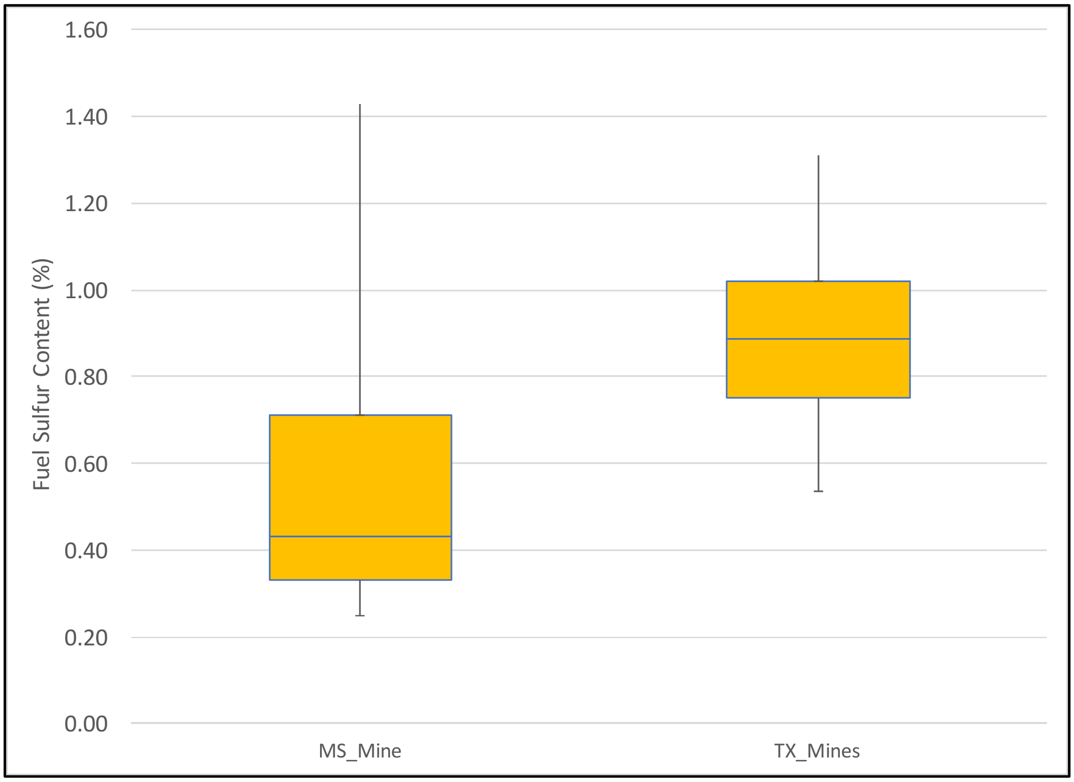

Figure 6-6. Sulfur Variability for Mississippi, Texas Lignite Mines19.1

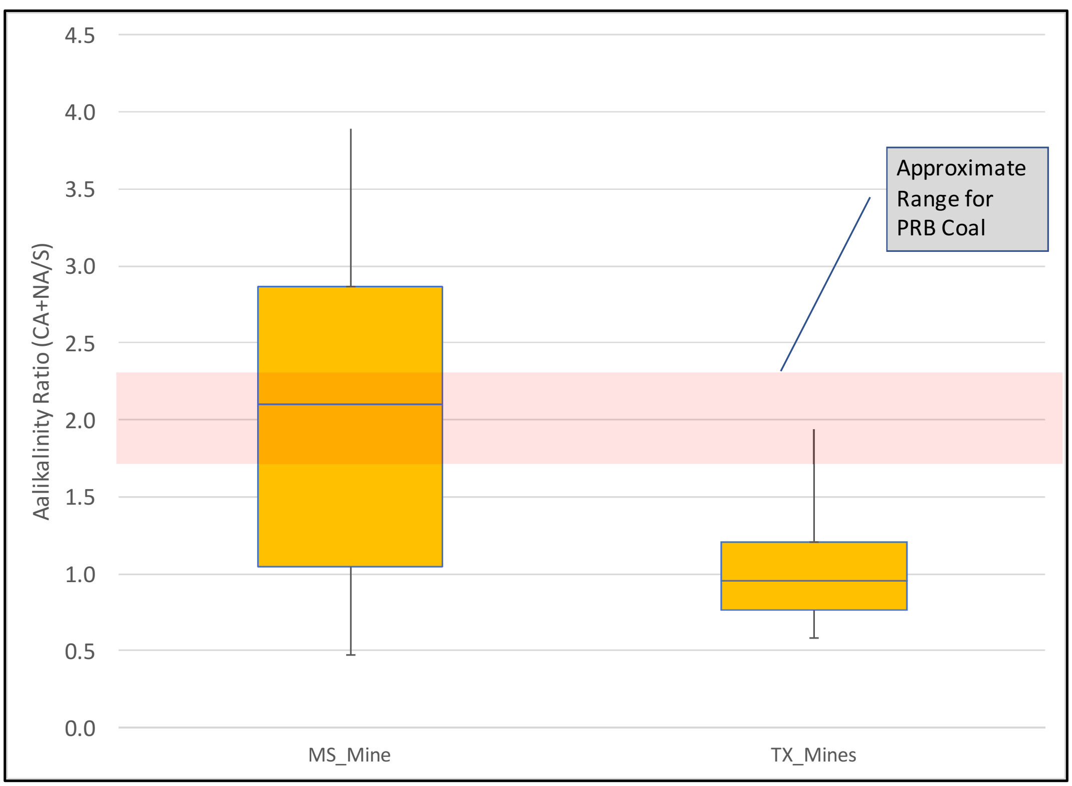

Figure 6-7. Fuel Alkalinity/Sulfur Ratio for Mississippi, Texas Lignite Mines

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

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

6.3 Role of Flue Gas SO3

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

6.3.1 EIA Hg-Sulfur Relationship

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

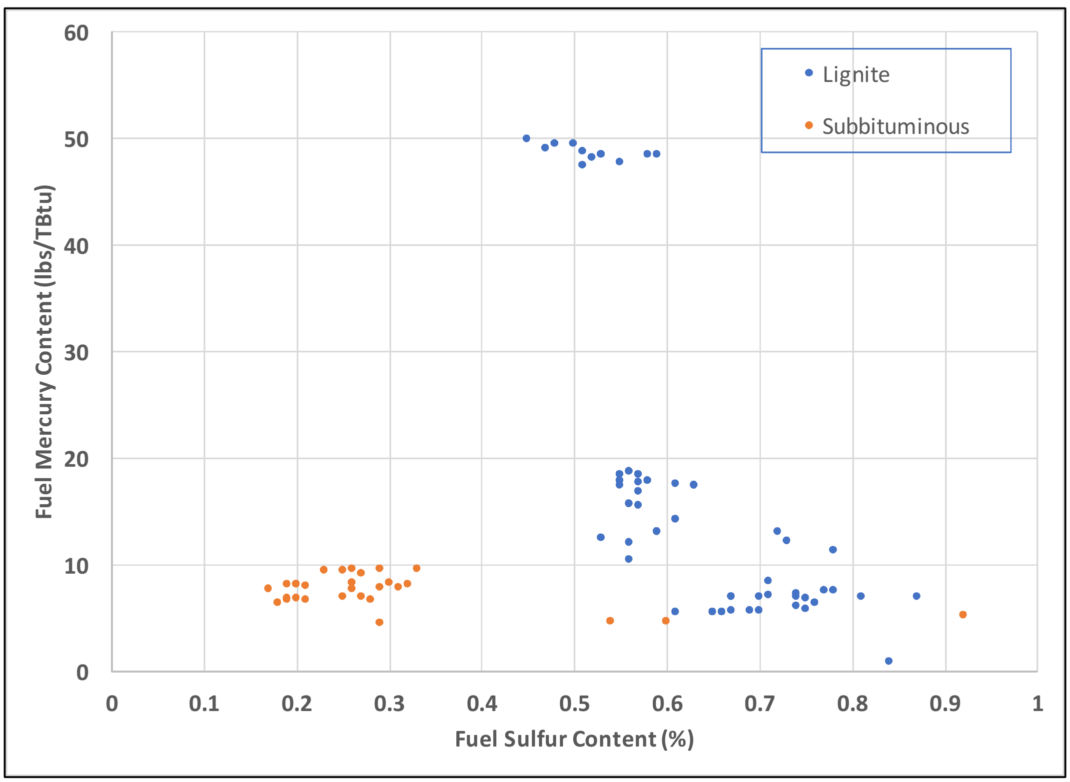

Figure 6-8. Lignite Hg and Sulfur Content Variability: 2021 EIA Submission

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

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

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

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

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

6.3.2 SO_3: Inhibitor to Hg Removal

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

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

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

[30] Tech Memo page 21
[31] Sjostrom 2019. See graphics 21-25
[32] Documentation for EPA's Power Sector Modeling Platform v6: Using the Integrated Planning Model, May 2018.
[33] IPM Model – Updates to Cost and Performance for APC Technologies: Mercury Control Cost Development Methodology, Prepared by Sargent & Lundy, Project 12847-002, March 2013.

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

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

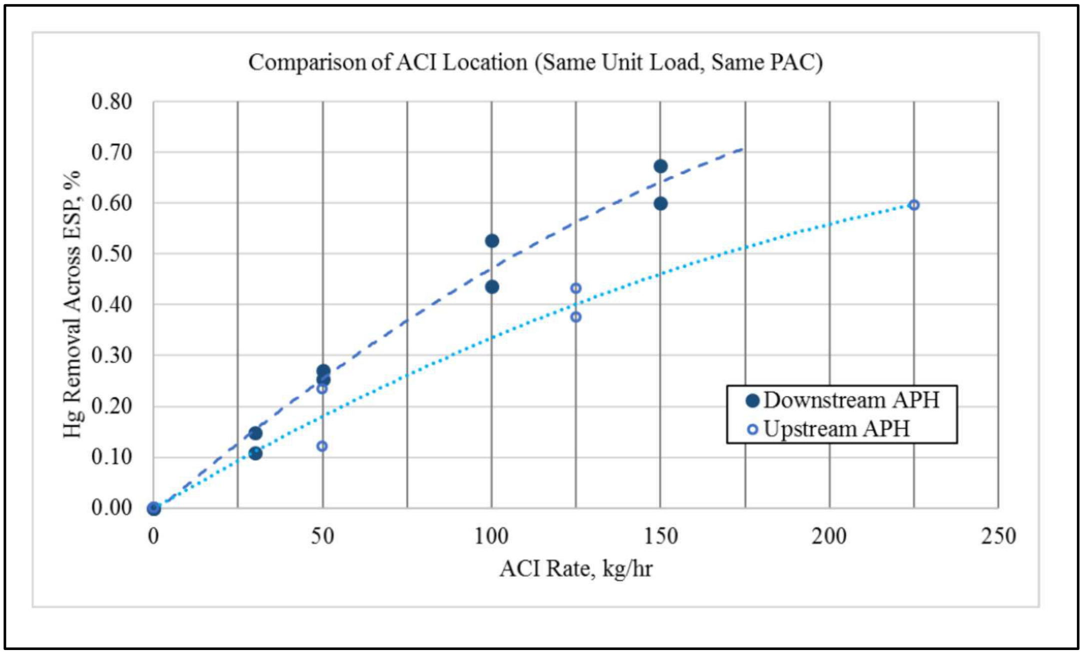

Figure 6-9. Sorbent Hg Removal in ESP in Lignite-Fired Unit: Effect of Injection Location

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

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

6.4 EPA Cost Calculations Ignore FGD

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

[34] Sjostrom 2016. See graphic 16.
[35] Satterfield, J., Optimizing ACI Usage to Reduce Costs, Increase Fly Ash Quality, and Avoid Corrosion, presentation to the Powerplant Pollutant and Effluent Control Mega Symposium, August, 2018.

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

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

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

6.5 Conclusions

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

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

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

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

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

7. Mercury Emissions: Non-Low Rank Fuels

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

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

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

7.1 Hg Removal

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

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

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

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

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[37] Prepublication Version, page 85

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

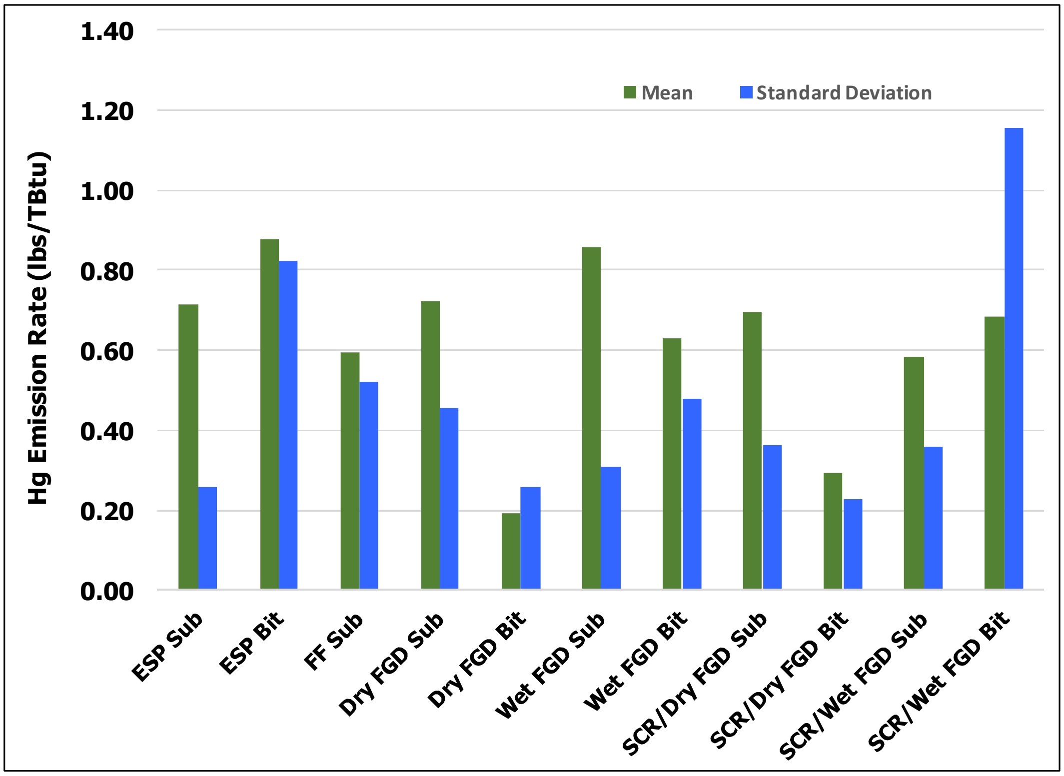

Figure 7-1. Mean, Standard Deviation of Annual Hg Emissions: 2018

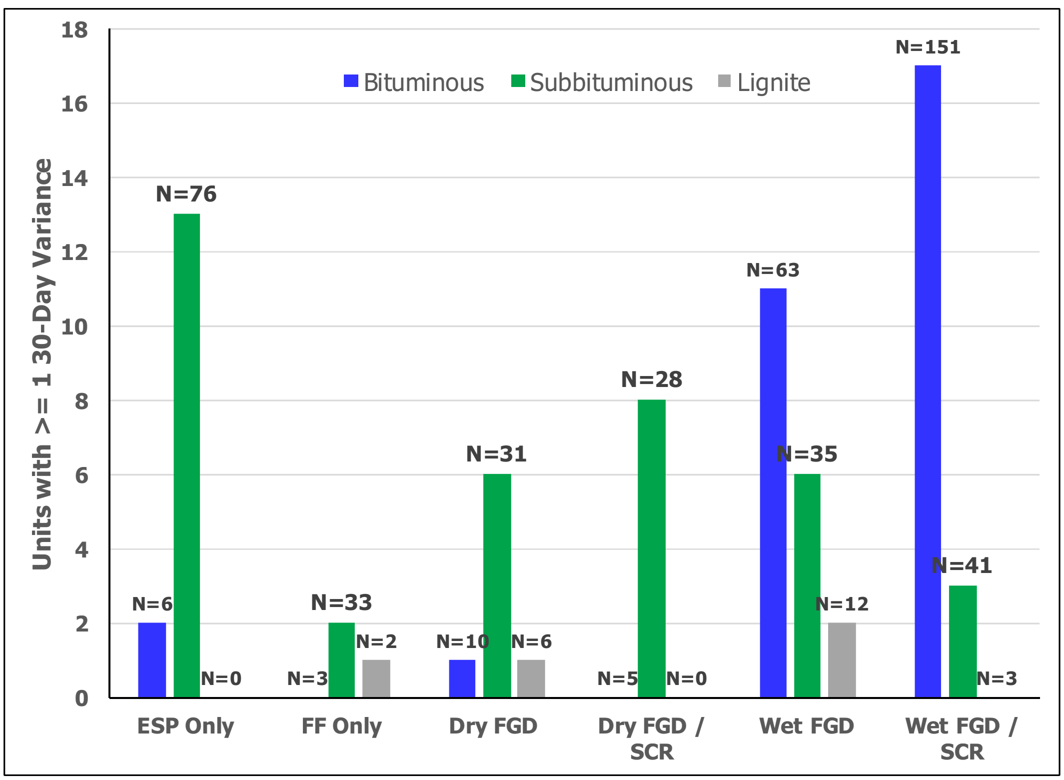

Figure 7-2. Mean, Standard Deviation of Annual Hg Emissions: 2018

7.2 Role of Fuel Composition and Process Conditions

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

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

7.2.1 Coal Variability

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

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

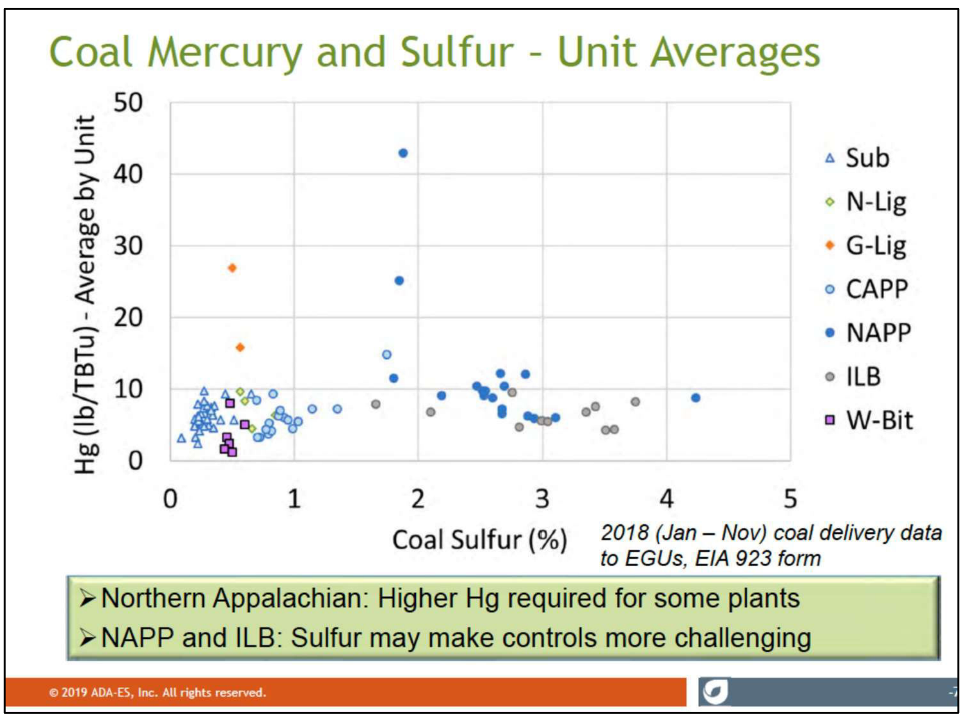

Figure 7-3. Annual Average of Fuel Hg, Sulfur Content in Coal

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[39] Sjostrom, S. et. al., Mercury Control in the U.S.: 2018 Year in Review
[40] RTR Tech Memo, page 19.

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

7.2.2 Process Conditions

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

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

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

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

This relationship is complicated by the role of Refined Coal, coal additives, and (as described below) the contribution of "co-benefits". *Devising a reasoned prediction of Hg removal under variable conditions, including coal composition and the impact of changing sorbents is not possible with current available information.*

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

[41] Sjostrom, S. et. al., Mercury Control in the U.S.: 2018 Year in Review. Hereafter Sjostrom 2019.
[42] Senior, C. et. al., *Reducing Operating Costs and Risks of Hg Control with Fuel Additives*, Presentation to the Power Plant Pollutant Control and Carbon Management Mega Symposium, August 16-18, 2016.

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

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

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

7.3 Conclusions: Mercury Emissions - Non-Low Rank Coals

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

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

8. EPA IPM RESULTS: EVALUATION AND CRITIQUE

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

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

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

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

8.1.1 Analytical Approach

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

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

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

8.1.2 Coal Retirements

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

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

Table 8-1. Coal Retirement Errors

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

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

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

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

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

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

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

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

Table 8-5 Units IPM Predicts CCS By 2030

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

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

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

8.1.3 Coal CCS

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

8.1.4 Coal to Gas Conversions (C2G)

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

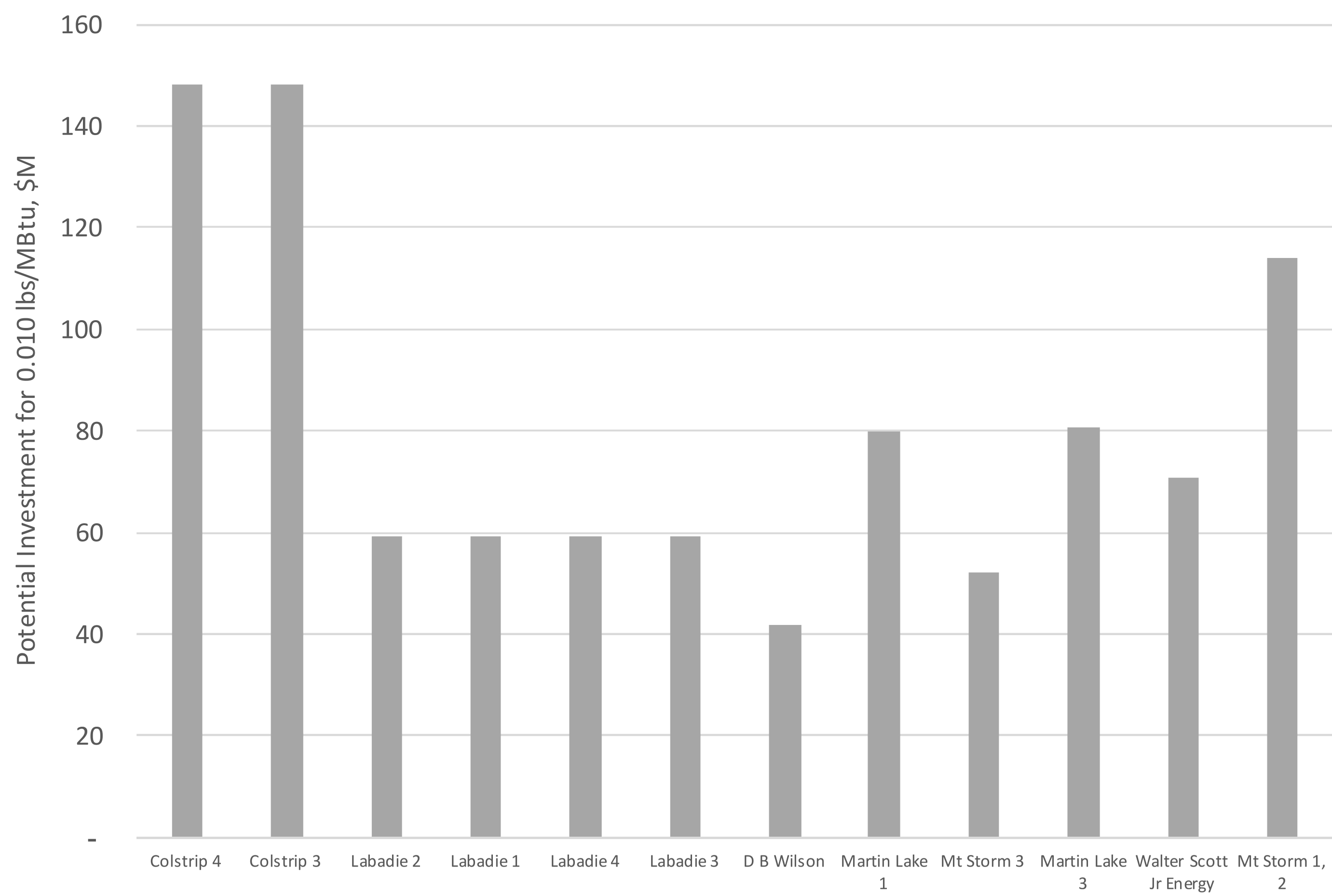
8.2 Summary

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

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

Appendix A: Additional Cost Study Data

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



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

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

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

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

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

Appendix B: Example Data Chart

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

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

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

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

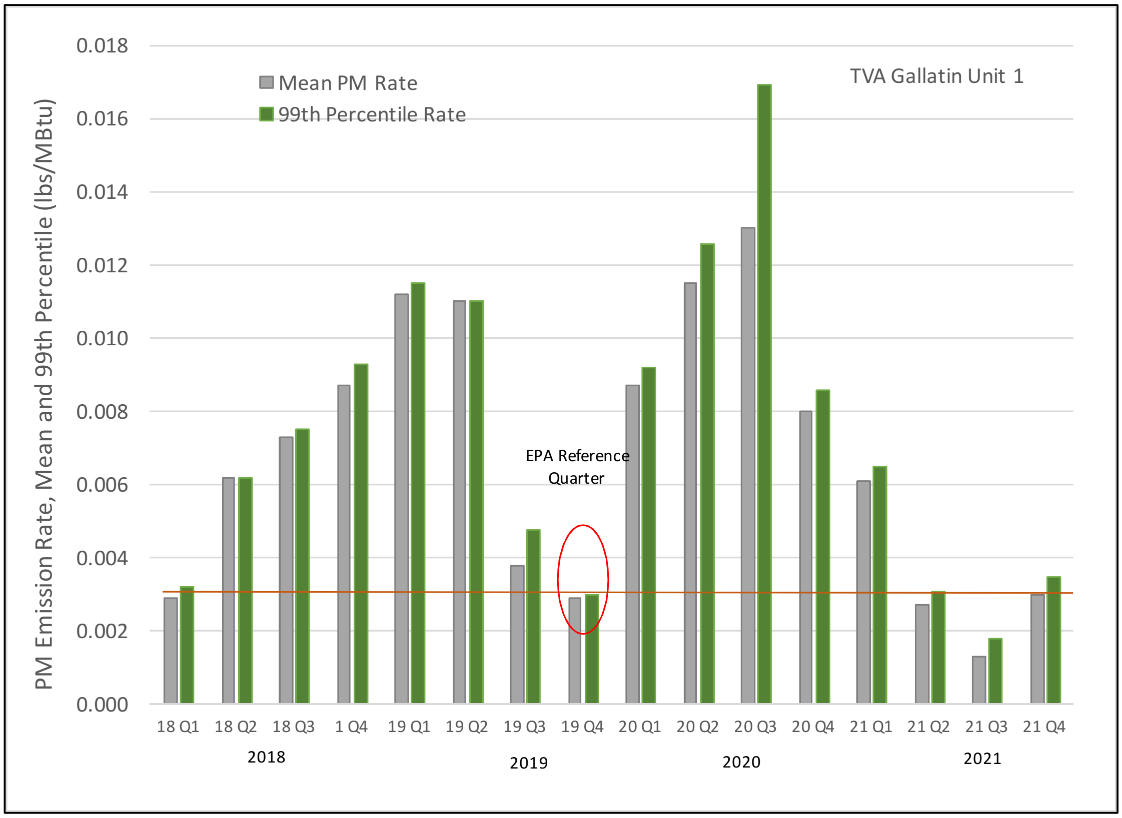
- TVA Gallatin Unit 4. EPA selected 0.0022 lbs/MBtu as the reference PM rate, using Q1 of 2021. Of the 14 quarters reporting data, two quarters report PM rates equal to this rate, while two are below this rate.

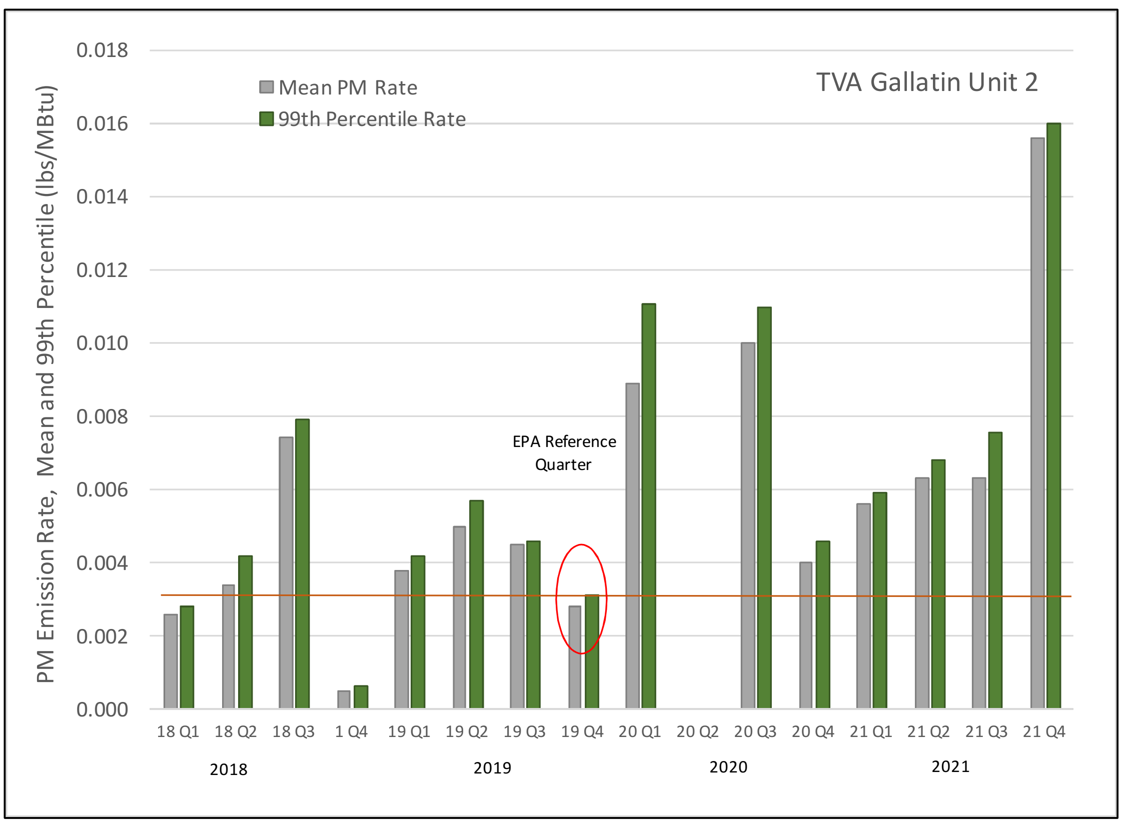
- LG&E/KU Ghent 1. EPA selected 0.005 lbs/MBtu as the reference PM rate, using Q2 of 2019. This PM rate represents that reported in previous quarters, but with one exception all subsequent quarters through 2021 report higher PM.

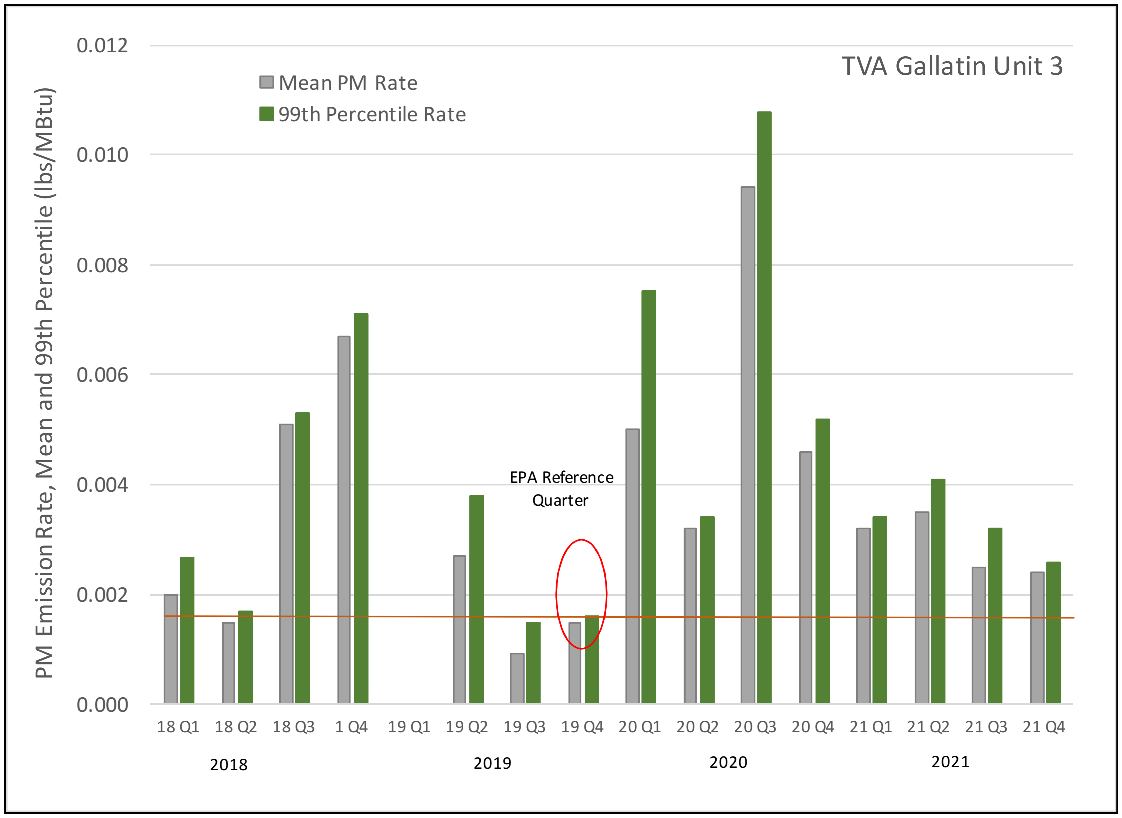
- LG&E/KU Mill Creek Unit 4. EPA selected 0.0035 lbs/MBtu as the reference PM rate, using Q4 of 2021. With the exception of the previous quarter, this value is the lowest of any reported since 2017 by a significant margin.

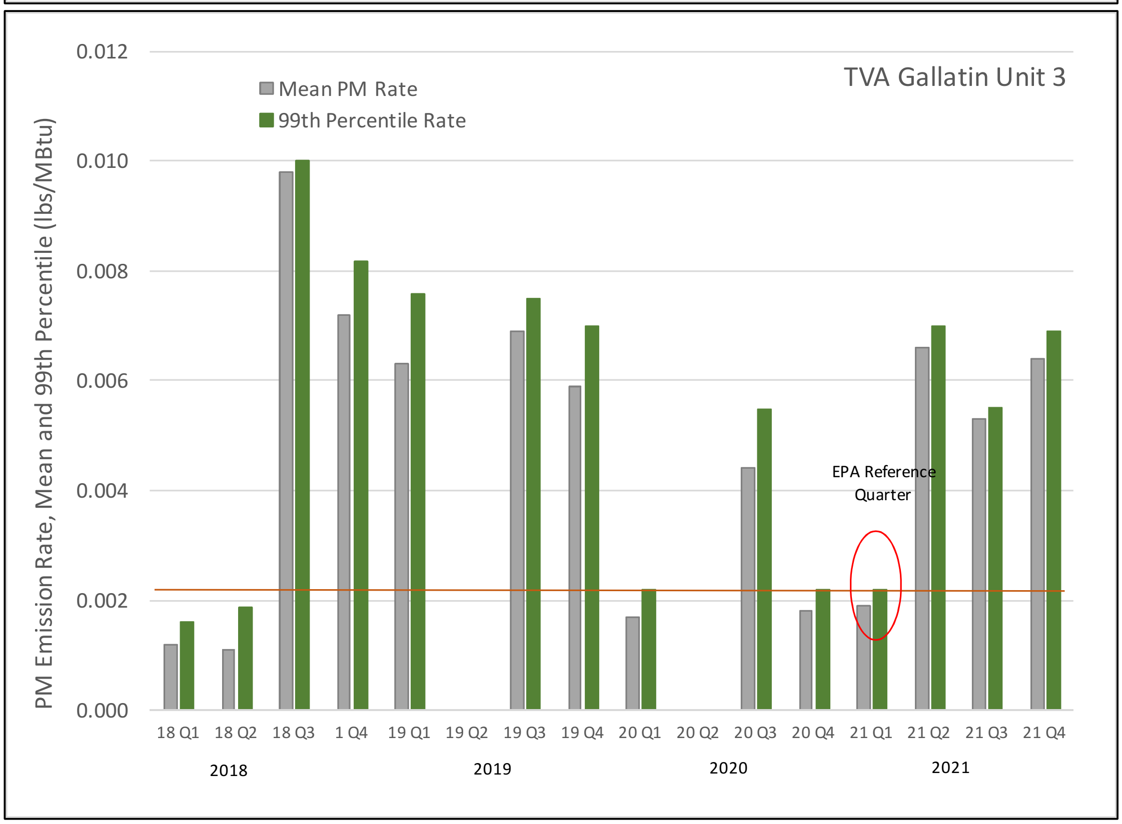
- Alabama Power Gaston Unit 5. EPA selected 0.005 lbs/MBtu as the reference PM rate, using Q1 of 2021. Data for this unit is displayed from Q1 2017 through Q4 2022. Of the 24 reporting quarters (1Q 2017 through 4QW 2022) only 6 quarters have lower PM rates.

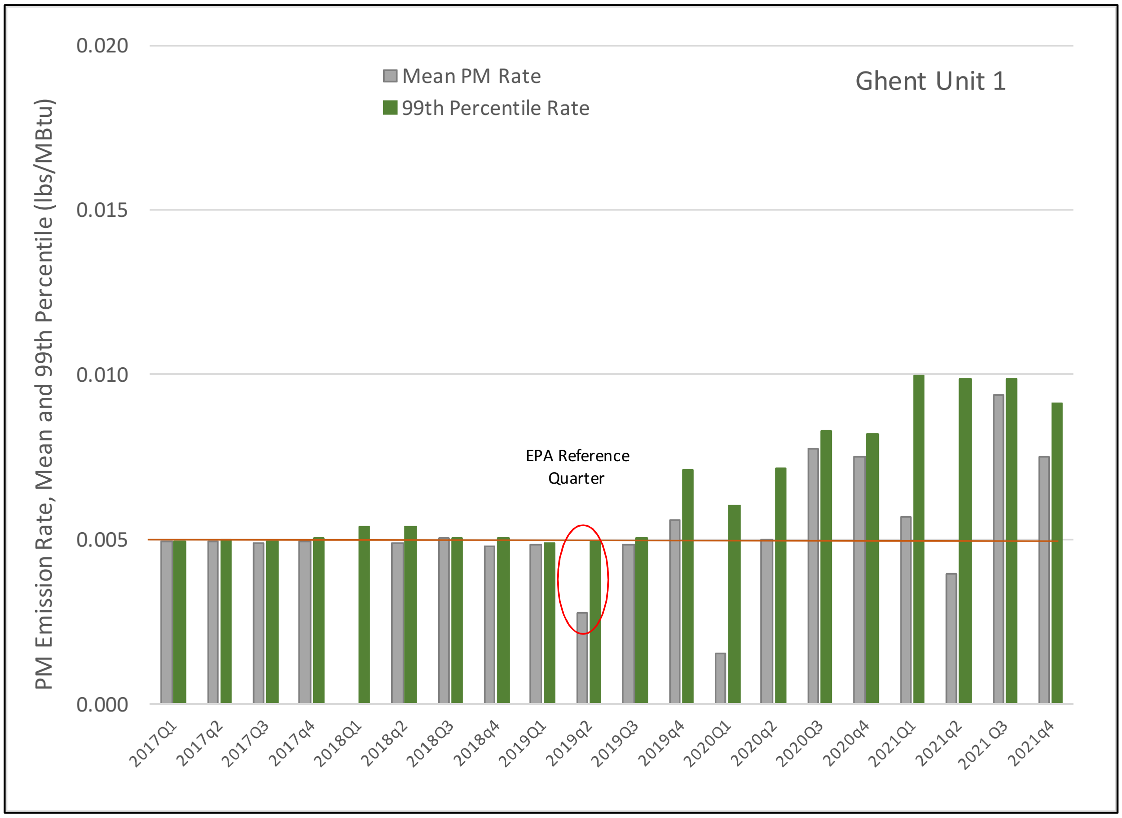
- Alabama Power Miller Unit 1. EPA selected 0.004 lbs/MBtu as the reference PM rate, using Q3 of 2017. Data for this unit is displayed from Q1 2017 through Q4 2022. The designated rate represents a significant reduction from approximately half of the reporting quarters since Q1 2020.


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


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


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


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


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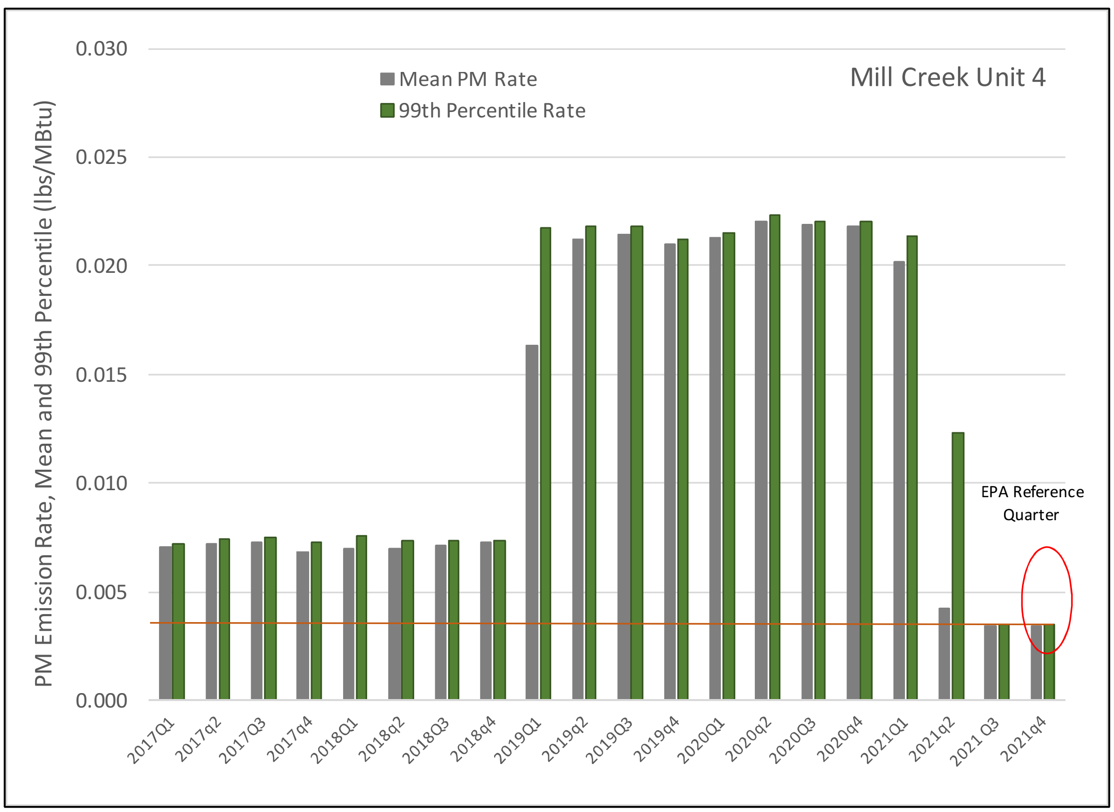
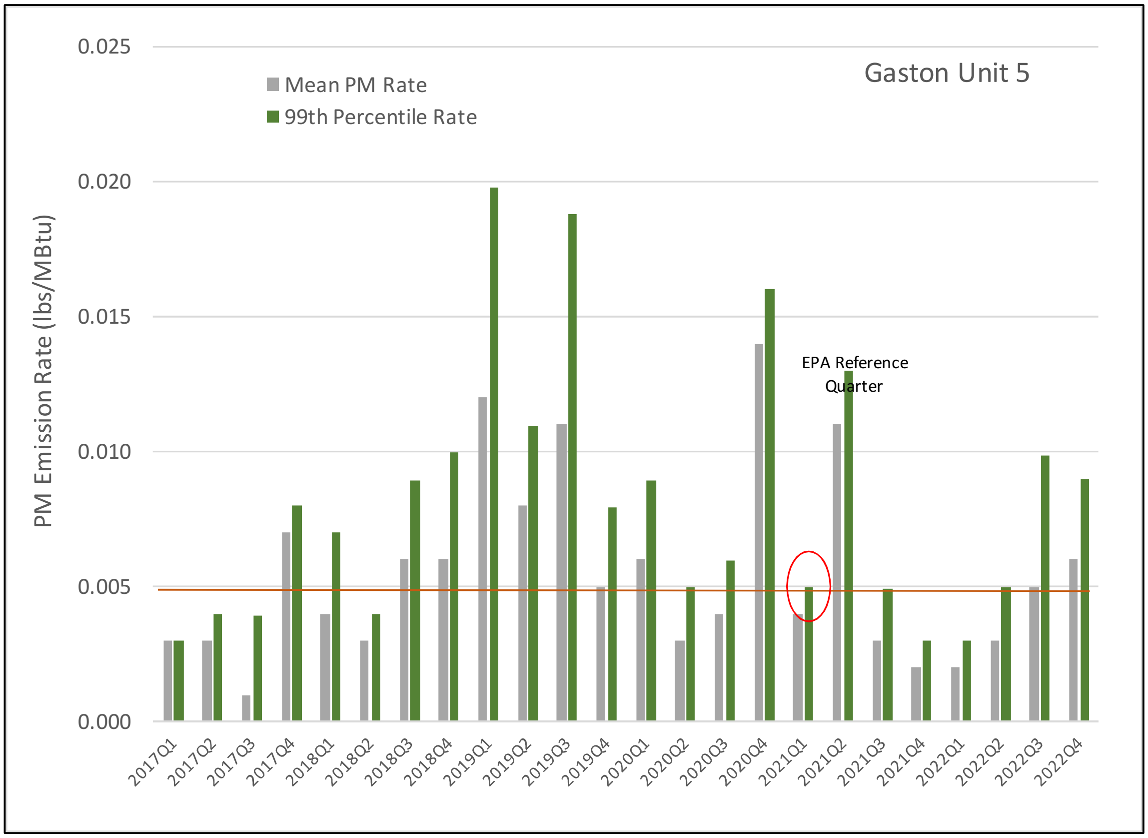
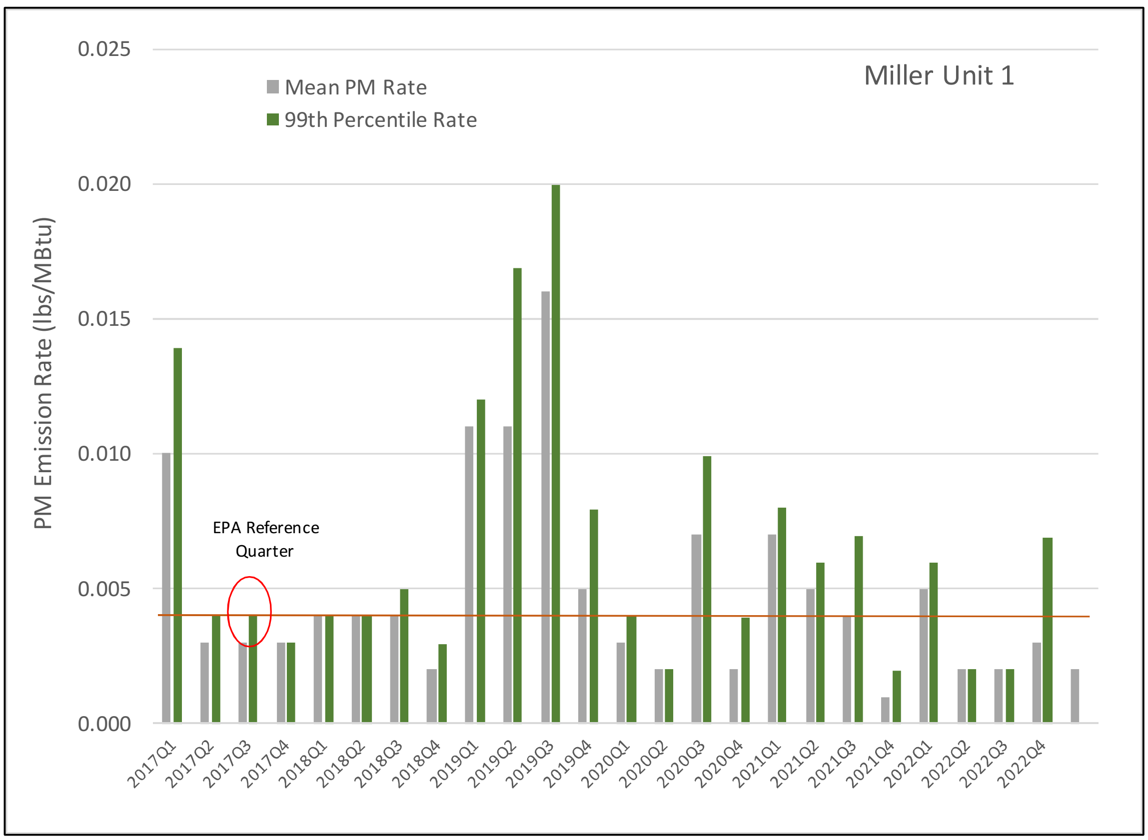
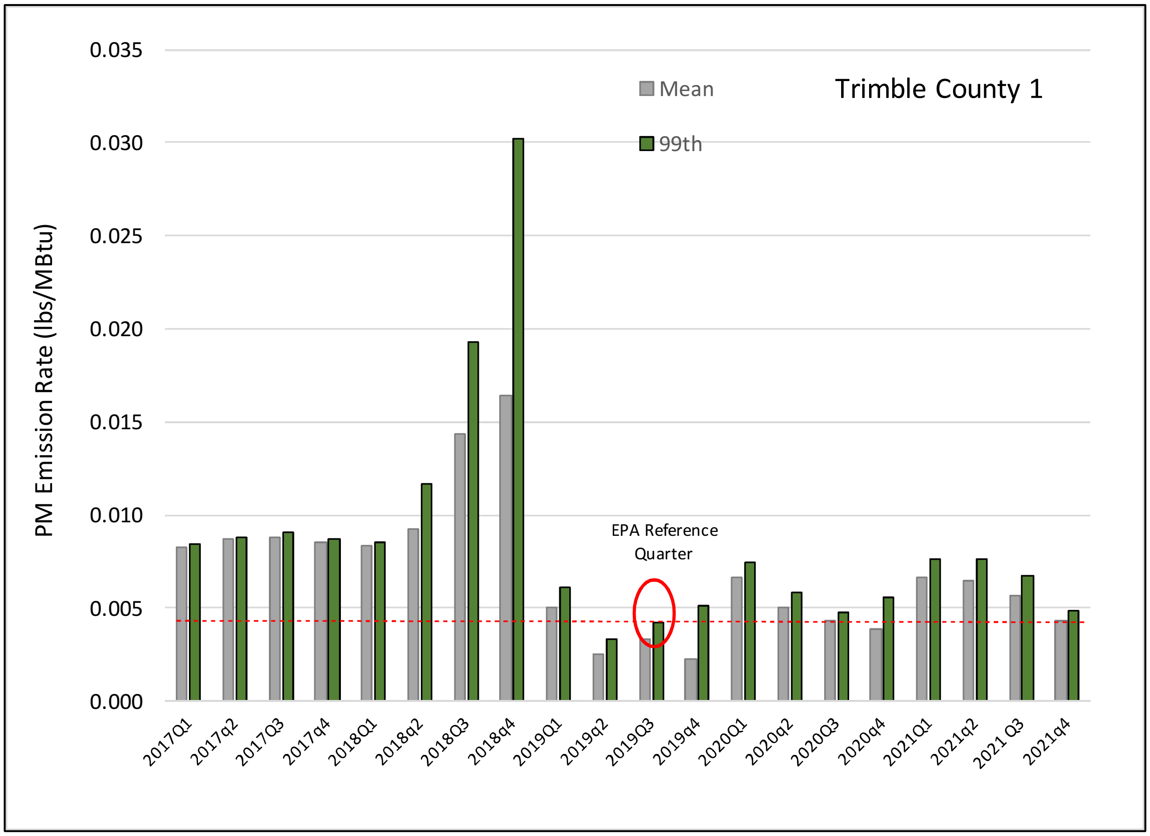
2021Q1
2021q2
2021 Q3
2021q4


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


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


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


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

ATTACHMENT C

MEMORANDUM

Date: December 16, 2011

Subject: Emission Reduction Costs for Beyond-the-floor Mercury Rate for Existing Units Designed to Burn Low Rank Virgin Coal

From: Kevin Culligan, SPPD/OAQPS

To: EPA-HQ-OAR-2009-0234

For the final rule, EPA has recalculated the beyond the floor control costs for existing units designed to burn low rank virgin coal using a methodology similar to that used in the IPM analysis done for the MATS proposal. In the final rule, we have not recalculated control costs based on the other methodology used in the proposal which used ACI capital and operating costs provided in the ICR. We have not used that approach because it was based upon an assumption that all units would need to have a baghouse (also known as a fabric filter – FF – either existing or newly installed) in order to meet the MACT PM standard and that the ACI would be used with the baghouse. EPA has considered and used additional information demonstrating that high levels of mercury removal can be achieved with injection of brominated activated carbon and the addition of a FF is not necessary. Furthermore, based on additional analysis related to the PM standard, EPA believes that most lignite units will not need to install new FF, therefore, EPA believes a costing methodology based on this assumption would be inappropriate.

For this analysis, EPA calculated beyond-the-floor costs for mercury controls by assuming injection of brominated activated carbon at a rate of 3.0 lb/MACF for units with ESPs and injection rates of 2.0 lb/MACF for units with baghouses (also known as fabric filters). The rate of 2.0 lb/MACF for fabric filters is consistent with the rate assumed in all other IPM analyses for this rule. The rate of 3.0 lb/MACF for units with ESPs is lower than the rate of 5.0 lb/MACF assumed in the IPM analysis. EPA believes that this rate is appropriate, because a higher rate would likely result in reductions beyond those needed to meet the BTF standard of 4.0 lb/TBtu. Figure 1 in "Activated Carbon Injection for Mercury: Overview"[1] suggests that > 90% control can be achieved at lignite-fired units at a < 2.0 lb/MACF injection rate for units with installed FF and using treated (i.e., brominated) AC. The figure also suggests that > 90% Hg control can be achieved at lignite-fired units at < 3.0 lb/MACF injection rate for units with installed ESPs and using treated AC. As Table 1 below shows, based on the IPM analysis, all units would need to achieve reductions of less than 90%, therefore lower assumed injection rates are appropriate.

[1] *Fuel Processing Technology* 89 (2010) 1310

Table 1 – Emission Reduction Rates Required to Meet Standard of 4 lb/TBtu.

Plant Name	Unit ID	Hg Controls	Existing Controls	Base Hg lbs/Tbtu	Reduction Required, %	Policy Hg lbs/Tbtu
Big Brown	1	ACI	Cold-side ESP + Fabric Filter + SNCR	9.09	55.98	1.01
Big Brown	2	ACI	Cold-side ESP + Fabric Filter + SNCR	9.09	55.98	1.01
Lewis & Clark	B1	ACI	Wet Scrubber	7.68	47.92	0.75
Martin Lake	1	ACI	Cold-side ESP + Wet Scrubber	5.41	26.09	0.56
Martin Lake	2	ACI	Cold-side ESP + Wet Scrubber	5.41	26.09	0.56
Martin Lake	3	ACI	Cold-side ESP + Wet Scrubber	5.41	26.09	0.56
Monticello	3	ACI	Cold-side ESP + SNCR + Wet Scrubber	6.30	36.53	0.96
R M Heskett	B1		Cold-side ESP	7.81	48.77	0.45
R M Heskett	B2		Cold-side ESP + Cyclone	4.76	16.00	0.75
Leland Olds	1		Cold-side ESP	7.68	47.93	0.77
Leland Olds	2		Cold-side ESP	7.81	48.77	0.78
Milton R Young	B1		Cold-side ESP + SCR + Wet Scrubber	4.21	4.93	0.75
Milton R Young	B2		Cold-side ESP + SCR + Wet Scrubber	4.21	4.93	0.75
Stanton	1		Cold-side ESP	7.81	48.77	0.78
Stanton	10		Fabric Filter + Dry Scrubber	7.51	46.76	0.75
Limestone	LIM1		Cold-side ESP + Wet Scrubber	6.75	40.76	1.13
Limestone	LIM2		Cold-side ESP + Wet Scrubber	6.75	40.76	1.13
Dolet Hills	1		Cold-side ESP + Wet Scrubber	8.33	51.98	1.35
Coal Creek	1		Cold-side ESP + Wet Scrubber	4.21	5.07	0.76
Coal Creek	2		Cold-side ESP + Wet Scrubber	4.21	5.07	0.76
Laramie River Station	1		Cold-side ESP + Wet Scrubber	5.31	24.71	0.56
Laramie River Station	2		Cold-side ESP + Wet Scrubber	5.31	24.71	0.56
Antelope Valley	B1		Fabric Filter + Dry Scrubber	7.51	46.76	0.75
Antelope Valley	B2		Fabric Filter + Dry Scrubber	7.51	46.76	0.75
Twin Oaks Power One	U1		Fabric Filter	5.82	31.33	1.35
Twin Oaks Power One	U2		Fabric Filter	5.82	31.33	1.35
Pirkey	1		Cold-side ESP + Wet Scrubber	7.59	47.27	1.35
Coyote	B1		Fabric Filter + Dry Scrubber	7.64	47.66	0.75
Great River Energy Spiritwood Station	1		Cold-side ESP + Fabric Filter + SNCR + Dry Scrubber	7.68	47.92	0.75

EPA also assumed a disposal cost of $25/ton for ash comingled with activated carbon. This cost is consistent with a range of studies. DOE/NETL, in a recent study examining the costs of ACI, assumed total disposal costs of $17/ton for non-hazardous fly ash. They assumed $35/ton for fly ash that would have otherwise been sold for beneficial reuse (lost revenue of $18/ton plus disposal costs of $17/ton for non-hazardous fly ash). [2] In an EPA study, $25 - $30 per ton were assumed as total disposal costs.[3]

EPA recently modeled site-specific disposal costs for the RIA[4] for the proposed rule regulating coal combustion residuals (CCRs), including fly ash. Those costs were examined for units burning low rank virgin coal. The disposal costs varied by state/region. For Texas the incremental costs attributable to Hg control were $18.13/ton, while for North Dakota and Montana, the incremental costs attributable to Hg control were $32.31/ton.

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[2] *Environmental Sci. Technol.* 2007, 41, 1365].
[3] *Environmental Sci. Technol.* 2006, 1385
[4] Regulatory Impact Analysis For EPA's Proposed RCRA Regulation Of Coal Combustion Residues (CCR) Generated by the Electric Utility Industry. Prepared by US Environmental Protection Agency Office of Resource Conservation & Recovery (ORCR) (formerly Office of Solid Waste) 1200 Pennsylvania Avenue NW (Mailstop 5305P) Washington DC, 20460 USA. Available at http://www.regulations.gov/ docket number EPA-HQ-RCRA-2009-0640-0003, Appendix H.

Based on these key assumptions, EPA projects an average reduction cost of $27,017 per pound of Hg removed. Unit by unit costs are provided in Table 2.

Table 2 – Unit by unit cost estimates for achieving an emission rate of 4 lb/TBtu Hg

Plant Name	Unit ID	Capacity (MW)	Heat Rate (Btu/kWh)	Existing PM Controls	(Base to Policy) Hg remv'd (lbm)	(2007$) unit S/lbm Hg	Total Cost
Big Brown	1	575	11001	Cold-side ESP + Fabric Filter + SNCR	-396	3954	1565723
Big Brown	2	575	10931	Cold-side ESP + Fabric Filter + SNCR	-393	3980	1565723
Lewis & Clark	B1	52.3	13787	Wet Scrubber	-31	22920	704682
Martin Lake	1	750	11512	Cold-side ESP + Wet Scrubber	-332	32175	10671737
Martin Lake	2	750	11202	Cold-side ESP + Wet Scrubber	-323	32174	10383770
Martin Lake	3	750	10784	Cold-side ESP + Wet Scrubber	-311	32309	10038209
Monticello	3	750	11246	Cold-side ESP + SNCR + Wet Scrubber	-359	29249	10487787
R M Heskett	B1	29.37	11985	Cold-side ESP	-17	38871	652353
R M Heskett	B2	75.5	11386	Cold-side ESP + Cyclone	-22	53992	1206545
Leland Olds	1	221	11404	Cold-side ESP	-109	25792	2812406
Leland Olds	2	448	11021	Cold-side ESP	-217	23822	5176973
Milton R Young	B1	250	10661	Cold-side ESP + SCR + Wet Scrubber	-64	51542	3272935
Milton R Young	B2	455	10661	Cold-side ESP + SCR + Wet Scrubber	-116	49018	5665257
Stanton	1	130.3472	10990	Cold-side ESP	-77	26601	2050240
Stanton	10	57.35278	10320	Fabric Filter + Dry Scrubber	-31	30538	935770.1
Limestone	LIM1	831	10102	Cold-side ESP + Wet Scrubber	-372	29034	10797351
Limestone	LIM2	858	10108	Cold-side ESP +	-384	28982	11134608

				Wet Scrubber			
Coal Creek	1	554	11219	Cold-side ESP + Wet Scrubber	-162	48056	7781365
Coal Creek	2	560.3	10818	Cold-side ESP + Wet Scrubber	-158	47982	7576786
Laramie River Station	1	565	11312	Cold-side ESP + Wet Scrubber	-235	34742	8170580
Laramie River Station	2	570	10953	Cold-side ESP + Wet Scrubber	-230	34737	7980115
Antelope Valley	B1	450	10988	Fabric Filter + Dry Scrubber	-264	22315	5888636
Antelope Valley	B2	450	11206	Fabric Filter + Dry Scrubber	-269	22269	5993120
Twin Oaks Power One	U1	152	9497	Fabric Filter	-50	38215	1900963
Twin Oaks Power One	U2	153	10364	Fabric Filter	-55	37778	2064287
Coyote	B1	427	11639	Fabric Filter + Dry Scrubber	-228	22122	5043515
Pirkey	1	675	10693	Cold-side ESP + Wet Scrubber	-349	26185	9140141
Great River Energy Spiritwood Station	1	99	8937	Cold-side ESP + Fabric Filter + SNCR + Dry Scrubber	-46	11694	535381.6
Dolet Hills	1	650	10674	Cold-side ESP + Wet Scrubber	-351	27064	9500464
				Total	-5948		1.61E+08
				Average		27016	

ATTACHMENT D

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Activated carbon injection for mercury control: Overview

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ABSTRACT

Full-scale evaluations of the commercial feasibility of activated carbon injection (ACI) for mercury control in coal-fired power plants have been underway in North America since 2001 through DOE, EPRI and industry-funded projects. Commercial injection systems began to be sold to the power generation industry in 2005 and ACI is now considered the most robust technology for mercury control at many coal-fired units. Successful widespread implementation of this technology throughout this industry will require continued development efforts including: (1) understanding the impacts of technologies to control other pollutants, such as SO_3, for the enhancement of particulate control or selective catalytic reduction (SCR) for NO_x control, (2) options to continue using ash containing activated carbon in concrete, (3) techniques to assure the quality of delivered carbon, (4) techniques to improve the effectiveness of activated carbon, and (5) facilities to produce additional carbon supply. An overview of activated carbon injection for mercury control will be presented including the range of expected control levels, costs, balance-of-plant issues, recent developments to reduce overall control costs for many common air pollution control configurations, and developments to overcome complications caused by some new control configurations. An update on carbon supply and progress on ADA's activated carbon manufacturing facility will also be provided.

1. Introduction

The power industry in the US is faced with meeting state imposed regulations, as well as expected federal legislation, to reduce the emissions of mercury compounds from coal-fired plants. In 2005 the Federal Clean Air Mercury Rule (CAMR) was signed into law and included mercury control requirements for new sources and a phased in implementation schedule for existing sources. Although the CAMR was vacated by the US District court in 2008, new plants permitted between 2005 and 2008 include mercury control equipment. In addition, over 100 existing plants have installed or are planning to install mercury control equipment in response to state regulations or consent decrees negotiated between a state and a power producer.

Several options have been considered to control mercury from coal-fired power plants. At some plants, effective mercury control is achieved as a result of synergistic effects with pollution control equipment designed primarily to remove other pollutants. For example, a plant firing bituminous coal with a selective catalytic reduction (SCR), which has been installed to reduce nitrogen oxides (NO_x) into N_2 and H_2O, can be effective at converting elemental mercury into oxidized mercury, which is water soluble. If the plant also uses a flue gas desulfurization (FGD) system where the flue gas contacts a wet alkaline slurry to remove sulfur dioxide (SO_2), a large fraction of the water-soluble mercury is also removed. However, plants firing western fuels that have SCRs and FGD systems do not achieve high mercury removal levels. Therefore, many plants, especially those firing western fuels, will need separate mercury removal systems to achieve the necessary emissions levels. For such plants, activated carbon injection (ACI) has been shown to be a cost-effective, reliable option.

In March 2009, the Institute of Clean Air Companies (ICAC) reported that mercury control systems had been ordered for 135 plants in the US and Canada, representing more than 55 GW of generation. Of these, 54 GW, or more than 98%, are ACI systems. The majority of the ACI systems ordered, 41 GW, were planned for units firing western coals (lignite or subbituminous) where ACI is most effective. It is expected that new federal regulations will be implemented in the future that will require mercury control systems on additional units.

2. Background: activated carbon injection for mercury control

Activated carbon is an effective sorbent for mercury capture from flue gas. Many years of research, development and over 50 full-scale demonstrations have shown that ACI can greatly reduce mercury emissions from most configurations, even where native mercury removal is low. ACI is the commercial mercury-specific air pollution control option of choice, but success at specific sites

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requires an understanding of factors that can impact effectiveness. Some of these can be addressed through careful system design, such as ensuring even distribution of the sorbent in the flues gas, providing sufficient time for the sorbent to contact and adsorb the mercury, and optimizing plant operation to maintain operating temperatures within an favorable range. Some challenges will require continued development efforts, such as improved sorbents, unless a change in fuel or the existing particulate control equipment can be implemented.

Activated carbon distribution is determined by the injection grid design, which requires access to ports in select locations, and is affected by mixing in the duct at the injection location, the particle size of the sorbent injected, and the amount of conveying air used to enhance distribution. Residence time varies with the configuration of the plant and distance to the particulate collection device as well as the type of particulate collection device (electrostatic precipitator (ESP) vs. fabric filter (FF)).

The effectiveness of activated carbon for mercury control is temperature dependent. Specifically, the mercury capacity of a particular sorbent typically increases as the flue gas temperature decreases. The flue gas temperature is primarily determined by plant design and operating factors. Depending on plant specifics such as flue gas constituents and operation of the particulate control device, mercury removal is relatively effective at temperatures below 350 °F. For most plants, typical air preheater outlet temperatures are between 250 and 400 °F and temperature can become a factor to consider when projecting mercury removal effectiveness.

Some flue gas constituents can aid mercury removal (i.e. halogens), while others can hinder it (i.e. SO_3 or NO_2). Halogens and hydrogen halides (primarily chlorine and bromine) are present in the flue gas from the coal or can be introduced through coal or flue gas additives. In low-halogen flue gas, halogen-treated activated carbon can be very effective at capturing mercury.

Examples of the impact of sulfur, specifically SO_3, on mercury control are presented in Fig. 1. This graph is a compilation of results from several activated carbon injection demonstration programs sponsored by the US DOE and industry. Several trends can be observed from the data in Fig. 1, including:

1. Fabric filters, including TOXECON™ units, which include fabric filters installed downstream of ESPs, are more effective when used in conjunction with activated carbon injection than ESPs alone.
2. Sites with low-halogen flue gas, including subbituminous coals from the Powder River Basin (PRB) and those with spray dryer absorbers (SDA) can achieve high levels of mercury removal using halogen-treated activated carbon.

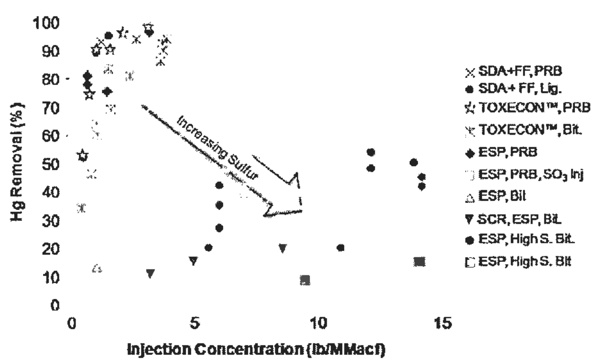

Fig. 1. Compilation of results from DOE mercury control programs.

3. ACI at sites firing western fuels, such as PRB coals or lignite (Lig.) coals, results in higher mercury removal than sites firing bituminous (Bit.) coals.
4. As the sulfur level of the coal increases, or when the SO_3 concentration is increased as a result of other pollution control devices, as will be discussed in the next section, the effectiveness of the activated carbon for mercury control decreases.

3. Industry-wide feasibility of activated carbon injection for mercury control

Although activated carbon injection is already a commercial mercury control option for many sites firing western fuels, continued development efforts have the potential to further expand implementation at sites where ACI is already an appropriate option and to increase applicability for other sites. Continued improvements in the technologies will involve: (1) reducing impacts created by other air pollution control equipment and operations, (2) continued improvements by activated manufacturers and equipment designers, (3) additional solutions to eliminate the impact of activated carbon on fly ash sales for use in concrete production, (4) procedures to ensure the quality of delivered carbon, and (5) increasing the production to sufficient quantities of activated carbon to meet industry-wide demand.

Interferences in the performance of ACI are often associated with increased levels of SO_3 and NO_2 created by equipment designed to reduce the emissions of other flue gas constituents. For example, some older-generation catalysts in SCR systems convert SO_2 to SO_3, sufficient amounts of which have been observed to impact the effectiveness of ACI for mercury control. These systems are being phased out and will not pose a problem for most sites. However, across the US, approximately 25 GW of power are produced from units firing PRB and low-sulfur bituminous coal that inject nominally 5–15 ppm SO_3 to improve ESP performance. SO_3 is used to "condition" the flue gas to improve particulate capture in ESPs on units firing low-sulfur coal. Chemicals to replace SO_3 for flue gas conditioning that do not detrimentally impact activated carbon performance are under evaluation. If such replacements are successfully utilized, it will increase the number of plants where ACI can be implemented.

The primary cost of mercury control with ACI is the sorbent. Additional reductions in costs can be achieved through proper system design, plant operation to maintain acceptable temperatures, and limiting SO_3 and NO_2 in the flue gas. Sorbent usage can be further decreased by lowering the mass mean diameter, and thus increasing the bulk surface area, of the activated carbon. During recent tests on units firing western subbituminous coal from the Powder River Basin (PRB), milling activated carbon resulted in a reduction of over 50% in activated carbon requirements [1,2]. Further tests are necessary to determine if the activated carbon usage can be further reduced, and the resulting effect on mercury removal.

Many units firing western fuels sell their fly ash as a replacement for Portland cement in the manufacture of concrete. In 2006, over 72 million tons of fly ash were produced in the US, 46% of which were used in concrete, concrete products, and grout [3]. Minute air bubbles entrained in the concrete matrix improve the durability of the concrete over freeze/thaw cycles. Carbon in fly ash is typically not desirable because it adsorbs chemicals designed to maintain air content in the concrete as it sets. Plants that sell their ash and choose to utilize ACI risk losing ash sales and potentially face landfilling the ash. Fly ash land filling costs are significant and can become one of the largest operating costs for plants after labor and fuel [4]. Options to preserve ash sales, while using ACI for mercury control, include separating the activated carbon-laden ash from the bulk of the fly ash by using

EPRI-patented techniques such as TOXECON™ [5] or TOXECON II™ [6], reducing the amount of powdered activated carbon required through techniques such as on-site milling, or use of a specialized ash compatible activated carbon. These specialized activated carbon sorbents are fairly new to the market and are being evaluated for their mercury control effectiveness and their impact on concrete properties. Another option being evaluated is the use air entraining agents that are not impacted by activated carbon. In addition, there are groups evaluating the effectiveness of separating the carbon and the ash through novel means such as triboelectrostatic separation.

Widespread use of ACI in the power industry will require that sufficient quantities are available and the quality and consistency of delivered activated carbon is maintained. During demonstration programs from 2001 through 2009, activated carbon deliveries of consistent quality were typically experienced. In a few cases, as vendors responded to the increased demand, key characteristics of the activated carbon varied, such as the density of the bulk material, bromine level, particle size, or the abrasive qualities of the sorbent [7]. These changes often led on significant impacts to the mercury removal, quantity of sorbent required, calibration of the feed equipment, and/or conveying system operation.

ADA Environmental Solutions (ADA), a leading developer of activated carbon injection technology and commercial activated carbon equipment supplier, estimates that upcoming federal and state regulations will result in tripling of the annual US demand for activated carbon to nearly 1.5 billion pounds from approximately 450 million pounds, requiring rapid expansion of production capacity. This will exceed the existing supply because the US activated carbon production plants that are already operating at near-capacity. ADA is currently constructing the largest activated carbon production plant ever built using state-of-the art components. Other manufacturers are also discussing expansion of their existing production capability. As production expands, it will be critical to work with reputable vendors and to develop internal processes to assure the quality of the as-delivered product.

4. Summary

The development and commercialization of ACI is a clear example of the dedication of emissions control technology developers, the power generation industry, and the DOE working together to meet the challenge of reducing mercury emissions from coal-fired power plants. ACI offers promise as a primary mercury control technology option for many configurations and an important trim technology for others that are not able to achieve 90% mercury capture by other means. As state regulations are implemented and the potential for a federal rule becomes more imminent, technologies are being developed to further reduce costs and limit the balance-of-plant impacts associated with ACI. In conjunction with the technology development, additional activated production facilities and quality assurance procedures are being developed to assure that industries needs are met.

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ATTACHMENT E

Minnkota Power Cooperative, Inc.
Milton R. Young Station Unit 2

Particulate & Mercury Control Technology Evaluation & Risk Assessment for Proposed MATS Rule

Final

June 23, 2023

Project No.: A14559.010

S&L Nuclear QA Program Applicable:

☐ Yes

☒ No

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1. INTRODUCTION

1.1. PURPOSE

Sargent & Lundy (S&L) was retained by Minnkota Power Cooperative, Inc. (Minnkota) to evaluate potential filterable particulate matter (PM) and mercury (Hg) emissions reductions in response to the proposed rule to amend the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Coal-and Oil-Fired Electric Utility Steam Generating Units (EGUs), commonly known as Mercury and Air Toxics Standards (MATS) published on April 24, 2023 that would require additional filterable PM and Hg emissions reductions on the Milton R. Young (MRY) Station Unit 2. These proposed revisions are the result of EPA's review of the residual risk and technology review (RTR) from May 22, 2020. Based on the proposed rule, EPA is planning to revise the filterable PM standards from 0.030 lb/MMBtu to 0.010 lb/MMBtu and is soliciting comments to consider even more stringent standard of 0.006 lb/MMBtu or lower. For lignite-fired units, EPA is also proposing to revise and tighten mercury emission standard from 4.0 lb/TBtu to 1.2 lb/TBtu to make it same as other units firing bituminous and subbituminous coal.

S&L reviewed the existing MRY Unit 2 PM and Hg control technologies to determine potential optimizations that could achieve incremental emission reductions as well as consider new PM and Hg control technologies. S&L prepared an evaluation of available control technologies including technical feasibility and effectiveness, and costs based on the current emissions from the unit. S&L's evaluation was completed based on past experience on similar projects, as well as input from established original equipment manufacturers (OEMs) regarding predicted performance for the lignite application at MRY Unit 2.

1.2. FACILITY BACKGROUND

The MRY station is located approximately seven (7) miles southeast of Center, North Dakota or forty (40) miles northwest of Bismarck, North Dakota on ND Highway 25 at 3401 24th Street SW, Center, North Dakota 58530. MRY station provides energy to the Midcontinent Independent System Operator (MISO) system. MRY station consists of two (2) units. Both MRY units are lignite-fired Babcock and Wilcox (B&W) cyclone boilers. The Unit 1 single wall cyclone boiler was placed into service in 1970 and has a typical output capacity rating of 257 MWg (gross). The Unit 2 opposed wall cyclone boiler (Carolina type, radiant pump assisted natural circulation) was placed into service in 1977 and has a typical output capacity rating of 470 MWg (gross). Both boilers fire North Dakota lignite coal supplied from BNI Coal, Ltd.'s Center Mine located in close proximity to the plant. Both units utilize selective non-catalytic reduction (SNCR) and separated overfire air (SOFA) systems for NOx control, fuel additive (halide injection) system and non-halogenated powdered activated carbon (PAC) for Hg control, dry electrostatic precipitators (ESP) for PM emissions control, and wet flue gas desulfurization (WFGD) systems for sulfur dioxide (SO_2) control.

1.3. DIFFERENCES IN MRY UNIT 1 AND 2 DESIGN & OPERATION

MRY Unit 1 and 2 have the same air pollution control equipment in series; however, the design of the equipment differ in ways other than unit MWg size. Of particular note, the Unit 2 ESP design attributes are superior to Unit 1, with use of a wider plate spacing (12 vs. 9 inches), and a higher specific collection area (375 ft^2/1000 actual cubic feet per minute (acfm) vs. 288 ft^2/1000 acfm). However, the Unit 2 ESP design consists of the first 2 fields' specific corona power = 160 W/1000 acfm and the last 2 fields = 240 W/1000 acfm, which is consistent with historic ESP designs where transformer-rectifier (T/R) sets were typically selected to provide lower current density at the inlet sections, where the dust concentration will tend to suppress the corona current, and to provide higher current density at the outlet sections, where there is a greater percentage of fine particles. In comparison, the Unit 1 ESP design does not follow this approach, with all fields' specific corona power = 493 W/1000 acfm and is currently achieving significantly lower PM emissions than Unit 2. The single Unit 1 WFGD vessel has four (4) slurry recycle pumps (SRPs). Each of the two (2) WFGD vessels on Unit 2 have five (5) SRPs.

Furthermore, manual cleaning of the boiler on Unit 1 is also able to include air preheater (APH) cleaning, whereas the large hoppers below the Unit 2 APH prevent APH washes from being completed during short-term boiler cleaning outages. The Unit 1 offline cleaning occurs on average every 110-115 days and requires the unit to be offline typically for three (3) days. The Unit 2 offline cleaning (only including APH tube rodding) occurs on average every 85-90 days and requires the unit to be offline typically for four (4) days.

1.4. CURRENT BASELINE EMISSIONS

Minnkota provided the past five (5) years of emissions to establish baseline emissions used for this evaluation. The baseline emissions were developed using data submitted by Minnkota to the EPA between January 01, 2018 through December 31, 2022 as part of emissions reporting requirements. For PM emissions, a 30-boiler operating day rolling average was selected as the baseline PM emission calculation methodology to be in-line with the permit reporting requirements. For Hg emissions, the maximum 30-boiler operating day experienced during the evaluation period was selected as the baseline Hg emission.

Table 1-1 — Baseline Unit 2 PM & Hg Emissions

Parameter	Units	Unit 2
PM Emissions	lb/MMBtu	0.015
Hg Emissions	lb/TBtu	3.90

2. PARTICULATE TECHNOLOGY EVALUATION

As part of this evaluation, PM control technologies were evaluated based on achieving post-upgrade emissions limits in accordance with the proposed emissions included in the April 24, 2023, MATS proposed rule, 0.010 lb/MMBtu and potentially 0.006 lb/MMBtu. The description and assessment of each control option are discussed in the sections below.

2.1. OPTIONS TO REACH 0.010 LB/MMBTU

2.1.1. Increased Boiler Cleaning Outages

When manual cleaning of the boiler occurs, the following unit operation indicates reduced economizer outlet temperatures and subsequently APH outlet temperatures. The fly ash resistivity is reduced at lower temperatures making it easier to capture in the ESP. The decrease in temperature would also slightly reduce the volumetric flow through the ESP, which may also allow for improved flow and velocity through the ESP, subsequently improving the ESP overall performance. Although scheduling short term outages to complete cleaning of the boiler on a regular basis (regardless of near-term long-term outages) has shown the ability to maintain emissions below the baseline emissions, a PM emission of 0.010 lb/MMBtu likely cannot be achieved and therefore this option was not considered further.

2.1.2. Flow & Distribution Devices

Uniform gas and dust distribution to each ESP casing will allow for uniform treatment/conditions of each casing to facilitate optimal performance of each. Concentrated flow and/or dust to a casing will require that casing to work harder than the others, ultimately contributing to and/or causing other operating inefficiencies within the ESP to reduce its PM removal capabilities. Replacement of existing inlet and outlet flow & dust distribution devices to achieve the latest standards of the Institute of Clean Air Companies (ICAC) Publication No. EP-7 will improve the ESP overall performance. Implementation of other flow correction devices to minimize sneakage between cells and/or around collecting fields as well as to minimize particle re-entrainment from hoppers and collecting surfaces when rapped can also be implemented, as required, to meet best industry practices, if not already implemented as part of ESP designs.

A detailed assessment including computational flow dynamic (CFD) analysis and physical flow model studies would be performed to determine the design and placement of all flow and dust distribution devices. New designs of perforated plates (with rappers) would be implemented to allow for the easy removal of fly ash into the first field hopper to minimize the potential fly ash accumulation in the inlet plenum. Although PM emissions reductions are expected to be achieved with this option, a PM emission of 0.010 lb/MMBtu likely cannot be achieved and therefore this option was not considered further.

2.1.3. Increased Power Supply

In an ESP, the collection efficiency is proportional to the amount of corona power supplied to the unit, assuming the corona power is applied effectively (maintains a good sparking rate). The resulting corona current charges the PM in the flue gas which are then attracted to the grounded, oppositely charged collecting plates. For a given flow rate, the collection efficiency will increase as the corona power is increased. To achieve a high collection efficiency, corona power is usually between 100 and 500 W/1000 acfm, but newer ESP installations have been designed for as much as 800-900 W/1000 acfm.

Increasing the power delivered into the ESP casing for this option would be done by replacing the T/R sets with higher rated power supplies, e.g. switch mode power supplies (SMPS), also referred as high frequency T/R sets, or 3-phase power supplies. Replacement of the T/R sets will require new cables, as the existing cables for 2-phase will need to be upgraded to accommodate 3-phase; cables are assumed to be able to be pulled while the unit continues to operate. Further assessment would be required to determine all electrical infrastructure modifications required, including the ability to reuse the existing MCC and T/R set controls. Although PM emissions reductions are expected to be achieved with this option, a PM emission limit of 0.010 lb/MMBtu with adequate operating margin likely cannot be achieved and therefore this option was not considered further.

2.1.4.Additional ESP Field

As ESP performance does depend on the number of fields in the direction of flue gas flow, the addition of another field will increase the amount of power that can be supplied to the ESP and provide incremental removal of the filterable PM. As approximately 80% of the ash is expected to be collected in the first field, with decreasing degrees of particulate removal in the following fields, the last field in the ESP casing is expected to have the least amount of fly ash removed. This option can be implemented by either increasing the sectionalization of the last field (adding a T/R set) or potentially by utilizing the ESP outlet nozzle to retrofit another independently operated ESP field.

Sectionalization in the direction of gas flow is not feasible without a rebuild of the fields to be sectionalized as the current high voltage frames span the entire length of the field. Therefore, this option is only feasible if a new field is added at either the inlet or outlet of the existing ESP casing (assuming space available). However, the retrofit implications of this option would be considered to be a large capital retrofit project in lieu of an equipment optimization. This option is not anticipated to provide significant enough cost savings compared to the other large capital retrofit options that will be evaluated later in this evaluation. Therefore, this option is not considered further.

2.1.5.Additional ESP Casing

Installation of additional ESP casings in parallel to the existing Unit 2 ESP casings would increase the specific collecting area (SCA) and improve the velocity and treatment time of the existing ESP casings. The smaller wing ESP casings would be installed adjacent to the existing ESP casings, one added to north of Casing A and one added to the south of Casing B. The new wing casings will utilize a separate support structure and new power supplies to be independent, stand-alone structures. It is anticipated that modifications to the inlet and outlet ductwork would be required to evenly balance the flow to the new casings. The hoppers of the new ESP casings would be tied into the existing fly ash handling system. Although PM emissions reductions are expected to be achieved with this option, a PM emission limit of 0.010 lb/MMBtu with adequate operating margin likely cannot be achieved and therefore this option was not considered further.

2.1.6.ESP Rebuild

Rebuilding the existing Unit 2 ESP would involve replacement of all internals, while only reusing the outer shell/walls, hoppers, support structures, and ash conveying system. To accomplish the rebuild of the ESP casings, the roof, T/R sets, high voltage bus ducts, top end frames, intermediate roof beams, the top section of the inlet and outlet nozzles and all internal components of the existing ESPs will be removed, and replaced with new equipment. The flow distribution and correction devices in the inlet and outlet plenums would be replaced to optimize the flue gas and fly ash distribution to the casings. The hot and cold roofs would also be replaced as well to accommodate construction activities.

Before moving forward with rebuild, a structural integrity and thickness study should be completed on the entire structure to ensure that the steel has not thinned as a result of normal long-term option. The design of the support structure (casing, structural members, and determination of ESP loads to steel), support steel and foundation will need to be reviewed to verify if acceptable for reuse or if modifications are required for the weight change in the ESP casings as a result of the rebuild, which may result in additional reinforcement required. The existing ash handling systems would be reused without requiring any modifications for the incremental increase in the amount of ash collected. It would be assumed that the complete rebuild of the ESP casings and optimization of the flow distribution/collection devices in the inlet and outlet nozzles should be capable of achieving no net increase in the current pressure drop across the ESP and therefore would not require modifications or replacement of the existing ID fans.

The level of rebuild and repair to the existing ESP casings will require a longer construction outage, most likely requiring a twelve (12) week outage, if not longer. Limited access to the Unit 2 casings will also limit the construction sequence, and may cause delays, further extending the outage. Winter weather conditions experienced at the site could also prolong the construction process. Additional construction personnel would likely be required to complete work in multiple areas in an effort to reduce the outage duration.

With this option, the PM emissions are estimated to potentially achieve an emission rate of 0.008 lb/MMBtu. However, vendors would likely have to complete a more detailed qualitative study in order to provide a guarantee and would require baseline testing to qualify ESP inlet and outlet emissions.

2.2. OPTIONS TO REACH 0.006 LB/MMBTU

To achieve PM emissions that would allow for compliance with the more stringent proposed standard, a baghouse would be required. It should be noted that a baghouse will likely not provide sufficient operating margin to achieve the proposed 0.006 lb/MMBtu emission rate. It will likely be challenging to obtain a guarantee below 0.006 lb/MMBtu from baghouse OEMs. However, a baghouse is not considered to be economically feasible[1] and is therefore not evaluated further. The baghouse installation options that could be considered, described below, and the expected timeline for implementation of this control option, described in Table 2-2, are included for reference only.

- Conversion of ESP to Baghouse:
  - The existing ESP casings would be reused and ESP internals and all roof mounted equipment would be removed. A vertical partition wall, running in the direction of gas flow from the hopper bend line to the tube sheet, would be constructed in the center of each ESP casing.
- Polishing Baghouse (Downstream of ESP):
  - The existing ESP would continue to operate. Due to the reduced inlet ash loading, a polishing

[1] A high-level estimation of the cost effectiveness of a baghouse retrofit on MRY Unit 2 is approximately $162k/ton, based on the annualized capital and O&M costs ($/yr) divided by the annual reduction in annual emissions (ton/yr).

baghouse can be designed using a 6.0 air-to-cloth (AC) ratio, which allows for a reduced footprint compared to a 4.0 AC ratio sized to handle the entire unit fly ash loading.
    - There is not adequate space available adjacent to the existing ESP casings for placement of a baghouse. Therefore, long tie-in ductwork will be required to route flue gas to an open area where the baghouse can be constructed. As such, the reduced size of the polishing baghouse is not anticipated to provide significant enough cost savings when compared to a baghouse that utilizes a 4.0 AC ratio.
- Baghouse (Primary PM Collection):
    - The existing ESP would be abandoned in place (could be demolished at a later date). As mentioned previously, long tie-in ductwork will be required to route flue gas to an open area where the baghouse can be constructed while the unit continues to operate in order to minimize the tie-in outage duration.

A baghouse is expected to have a pressure drop of 8 in. w.c., but could be higher depending on the location of the baghouse in relation to the tie-in to the existing flue gas path. The current axial fans are already operated very close to their stall curve, and do not have any pressure drop operating margin. Therefore, either replacement of the existing ID fans or installation of new booster fans would be required to accommodate the additional pressure drop through the baghouse.

2.3. PARTICULATE EMISSIONS SUMMARY

Table 2-1 below provides a summary of the post-upgrade achievable emission rate for the feasible PM control option evaluated to achieve a proposed PM emission limit of 0.010 lb/MMBtu. The estimated emission rates included in the following tables are considered to be representative of an average emission rate that could be achieved under normal operating conditions. The emission rates provided **should not be** construed to represent an enforceable regulatory or proposed permit limit. Corresponding regulatory and/or permit limits must be evaluated on a control system-specific basis taking into consideration normal operating variability (i.e., a minimum additional 20% margin would likely be needed to account for operating margin).

Table 2-1 — Unit 2 PM Emissions Summary

Parameter	Control Efficiency Note 1	Projected Emissions Note 2 (lb/MMBtu)	Expected Emissions (ton/year)
Baseline (Dry ESP)	**--**	**0.015**	**254**
ESP Rebuild	46.7%	0.008	135

Note 1 – Control efficiency is based on incremental improvement achieved with the option in addition to baseline dry ESP operation (e.g. not to be misconstrued as a total percent removal from uncontrolled PM emissions).
Note 2 – No compliance margin is included in these estimates. The emissions rate projections should not be used as an achievable limit for these upgrades.

2.4. TIMELINE FOR INSTALLATION

A high-level implementation schedule that outlines the time needed for the project steps necessary for the implementation of the feasible control options are summarized below. It should be noted that although a baghouse is not considered to be economically feasible, the control option is included in the summary below for reference on the expected timeline required for implementation of this control option. Other project-related activities, such as the time needed to obtain internal project approval, financing or permitting, if required, are not included. It should be noted that these time frames are separate from the regulatory time frames for EPA to take final action on the Proposed MATS RTR.

Lead times of equipment that would be used in these types of retrofits have been observed to be double or triple the lead times typically provided by suppliers before the COVID pandemic, with longer durations observed for electrical and instrumentation and control equipment. With continued supply-chain issues, it is anticipated that longer and longer lead times may be required that are difficult to quantify at this time. Therefore, timelines represented are estimated based on past project durations and not reflective of post-pandemic market delays nor the limited number of experienced OEMs capable of providing the equipment.

Table 2-2 — PM Control Implementation Schedule

PM Control Option	Design/ Specification/ Procurement (months)	Detail Design/ Fabrication (months)	Construction/ Commissioning/ Startup (months)	Minimum Total (months)
ESP Rebuild	8	16	12	36
Baghouse	10	20	18	48

3. MERCURY TECHNOLOGY EVALUATION

3.1. MERCURY EMISSIONS BACKGROUND

3.1.1. Mercury Speciation

Mercury (Hg) is contained in varying concentrations in different coal supplies. During combustion, Hg is released in the form of elemental Hg in the high temperature combustion zone of a boiler. As the combustion gases cool, a portion of the elemental Hg transforms or oxidizes to ionic Hg. However, the amount of elemental Hg that oxidizes is dependent on the cooling rate of the gas and the presence of halogens in the flue gas. Ultimately, there are three possible forms of Hg:

- Elemental (Hg^0):
  - The conversion of elemental Hg to the other forms depends upon several factors including cooling rate of the gas, presence of halogens or sulfur trioxide (SO_3) in the flue gas, amount and composition of fly ash, presence of unburned carbon, and the installed APC equipment.
  - Hg^0 is insoluble in water and therefore removal requires injected sorbents or must be converted to another form to be captured, depending on the installed APC equipment.
- Ionic or Oxidized (Hg^{++} or Hg^{2+}):
  - In contrast to elemental Hg, ionic Hg is highly water soluble, allowing for collection in water streams that may be utilized in certain APC equipment and subsequently leave the process with the solid by-product or as a constituent in the purge water.
- Particulate-bound:
  - Particulate-bound Hg typically is bound to fly ash or unburned carbon. Particulate-bound Hg is efficiently removed from the flue gas by the particulate control device, making it desirable to convert as much Hg as possible to particulate-bound Hg.
  - High SO_3 levels have been shown to inhibit the binding of ionic Hg to fly ash or Hg sorbents. The addition of halogens increase the conversion of elemental and ionic Hg to particulate-bound Hg.

The proportion of the various Hg forms is referred to as Hg speciation. As such, Hg speciation testing has indicated that the distribution of Hg species varies with coal type. The effectiveness of post-combustion Hg control technologies is highly influenced by the Hg speciation in the flue gas, with gaseous oxidized (or ionic) Hg compounds (i.e. $HgCl_2$) being easier to capture by downstream APC equipment.

3.1.2. Lignite Coal Variability

Industry experience has shown that lignite coal deposits vary significantly in quality, including fuel combustion performance, mineral content, and Hg content, resulting in a coal that can change on a day-to-day basis depending on the coal seam being mined at the time. For example, during the 2005 Energy & Environmental Research Center (EERC) sixty (60) day testing on MRY Unit 2,[2] the coal samples analyzed ranged from 6.22

[2] Refer to the EERC "Large-Scale Mercury Control Technology Testing for Lignite-Fired Utilities - Oxidation Systems for Wet FGD" report (Cooperative Agreement No. DE-FC26-03NT41991) dated March 2007 for further details on the testing completed from March 15, 2005 to May 15, 2005 on MRY Unit 2.

lb/TBtu to 10.9 lb/TBtu (Hg content varied from 0.05 to 0.25 ppm, and averaged 0.112 ± 0.014 ppm on a dry coal basis). As such, units firing lignite coal with lower heating values have to accommodate frequently changing coal quality and require a wide range of flexibility to account for instances of firing high Hg seams of coal to consistently achieve adequate operating margin below the required Hg emission limit.[3]

The variability of the projected lignite coal quality received from the Center Mine from 2025 through 2036 is shown in Table 3-1.

Table 3-1 — Center Mine Ultimate Coal Analyses (As-Received)

Fuel Parameter	Units	Average	Minimum	Maximum
Carbon	wt.%	40.53	39.73	41.24
Hydrogen (fuel-based)	wt.%	2.78	2.71	2.82
Nitrogen	wt.%	0.30	0.26	0.34
Sulfur	wt.%	0.86	0.68	1.07
Oxygen (by difference)	wt.%	9.97	9.47	10.83
Moisture	wt.%	38.83	38.53	39.25
Ash	wt.%	6.73	6.00	7.87
Higher Heating Value (HHV)	Btu/lb	6,625	6,489	6,739
Mercury Content	ppm	0.091	0.053	0.184
Estimated Hg Emission	lb/TBtu	8.41	4.79	17.42

3.1.3. Hg Removal with ESPs

For ACI on ESP applications, 80% of Hg capture occurs in the flue gas, and 20% occurs on the dust within the ESP (as the dust on the collecting plates are consistently removed as part of the process). Therefore, for ESP applications, achieving ideal mixing and residence time to allow for elemental Hg to oxidize to ionic Hg and for Hg to be adsorbed on the carbon particles (of the PAC or unburned carbon content in the fly ash) is critical. It should be noted that this ratio is the exact opposite for baghouse applications, i.e. 20% capture in-duct and 80% capture on the dust of the filter cake accumulated in the baghouse. For this reason, fabric filters can result in extremely high Hg capture and can improve the capture with any Hg sorbent.

3.1.4. Existing System Limitations

Documented evidence of a lignite unit achieving 1.2 lb/TBtu or below has not been found/reviewed at the time of this report. Minnkota personnel recently completed short-term parametric testing in May 2023 to determine the Hg emissions that could be achieved by maximizing the existing fuel additive and PAC injection. Even when maximizing the fuel additive rate in addition to maximizing the non-halogenated ACI addition, an emission rate of 1.2 lb/TBtu was not able to be achieved. Due to the variability of the coal, a longer period of testing would be required to gauge the Hg emissions that could be achieved just using the capacity within the existing equipment.

[3] Based on Response of Minnkota Power Cooperative Clean Air Act Section 114 Request, dated July 29, 2022.

3.2. INCREMENTAL HG CONTROL ON A LIGNITE UNIT

As mentioned previously, S&L is not aware of any documented evidence of a lignite unit achieving 1.2 lb/TBtu or below. As such, the following sections describe issues that need to be resolved/tested to establish if it is feasible to achieve a 1.2 lb/TBtu Hg emission rate with sufficient operating margin on a lignite unit and if so, develop an overall Hg compliance approach that likely would consist of a suite of control approaches. It should be noted that any achievable Hg emission should not be construed to represent an enforceable regulatory or proposed permit limit. Corresponding regulatory and/or permit limits must be evaluated on a control system-specific basis taking into consideration normal operating and coal variability (i.e., a minimum additional 20% margin or higher would likely be needed to account for coal fluctuations and operating margin).

3.2.1.Increased Oxidation of Elemental Hg

Recent 2011 Hg speciation data measured at the Unit 2 stack, with no control technologies, indicated the Hg emissions consisted of approximately 98.3% elemental Hg, 0.8% oxidized Hg, and 0.9% particulate Hg. Recent operating data from a retired Hg process monitor indicates that the Unit 2 Hg emissions, with the currently installed Hg control technologies, consisted of approximately 86% elemental Hg, and 14% oxidized Hg. Because the current Hg emissions are made up mostly of elemental Hg, the unit emissions would benefit from an increased amount of halogen in an attempt to oxidize the elemental Hg in the flue gas. The additional halogen (chlorine, iodine, and bromine) can be added to the PAC, to the coal, or both.

The current fuel additive injection could be increased and/or replaced with a different halogen-based additive. In addition, the current non-halogenated PAC would be replaced with a more expensive halogenated PAC. The increased amount of halogen present is expected to increase the amount of elemental Hg that is oxidized to be more easily captured on the surface area of the PAC and in downstream APC.[4]

3.2.2.Increased PAC

It is anticipated that additional halogenated PAC (i.e. more than the current capabilities of the existing equipment) will need to be injected for the increased amount of oxidized Hg to be efficiently captured. However, preliminary feedback received from PAC suppliers have indicated that demonstration testing would be required to determine a PAC dosage rate and the emissions rate that can be achieved when considering the Hg content variability of the lignite. Therefore, additional modifications that may be required cannot be concluded at this time; however, it is likely that the existing lances and transport piping would need to be replaced to accommodate a higher injection rate. As the existing PAC storage silo is shared by Units 1 and 2, it is likely that a separate silo would be required for Unit 2 to ensure adequate supply, turndown flexibility, and reliability is achieved to maintain compliance with a defined Hg emission limit.

The degree of increased PAC injection rates can have an impact on the ESP performance as the increased amount of carbon particles that have low resistivity will decrease the overall resistivity of the fly ash (can cause particles to rapidly lose their charge on arrival at the collecting plate and become re-entrained). If/when

[4] It should be noted that the existing PAC silo is not currently compatible to store halogenated PAC due to the material of construction of the fluidizing air nozzles and may also require an internal coating of the silo to prevent corrosion. Additional assessment will be required to determine modifications required to reuse the existing silo, and may be subject to the brominated PAC utilized.

additional testing is completed to determine the supplier recommended brominated PAC injection rate, PM emissions should also be closely monitored to confirm no longer term impacts are caused by the increased ACI rate. In order to mitigate potential increases or deviations for the current PM emissions, it would be reasonable to anticipate some ESP upgrades (operational changes and/or equipment optimizations) to be required to ensure the ESP maintains its current performance.

3.2.3.Increased Contact

Increasing the degree of flue gas and PAC mixing can optimize the sorbent utilization to ensure adequate mixing of the oxidized Hg and PAC is achieved, which potentially could result in the use of less PAC to achieve the same Hg emission rate. Similarly, additional testing and evaluation would be required to determine the beneficial incremental Hg removal improvement that could be achieved. Additional mixing could be implemented by either adding static mixers into the flue gas path and/or using a more advanced injection lance design to increase sorbent dispersion relative to a straight lance design to optimize sorbent usage.

Increased contact time could also be achieved by relocating the injection lances upstream of the APH.[5] Hg reduction effectiveness with PAC has been shown to be temperature limited, as the absorption capacity of the carbon is reduced at temperatures above approximately 350°F. Although flue gas temperatures downstream of the APH are more ideal for capture, temperatures upstream of the APH are within an ideal zone for mercuric halogens to be formed, taking advantage of the additional halogen introduced with the PAC. Furthermore, for applications with SO_3 concentrations above 5 ppm in the flue gas (as-is on the MRY units), carbon active sites may be preferentially occupied by SO_3. Although adsorption rates slow down above 350°F, injection upstream of the APH is sometimes considered to lower the impact of SO_3 competition. Furthermore, tubular APH designs will not offer as much mixing compared to Ljungstrom type APHs; therefore, relocating the injection lances upstream of the APH will likely only achieve added residence time for adsorption to occur in lieu of additional mixing. Therefore, the high temperature environment and resulting residence time for injection at the APH inlet would need to be evaluated further.

3.2.4.WFGD Re-Emission Control

Oxidized Hg is highly water soluble and exists in vapor phase at back-end equipment flue gas temperatures. WFGDs readily capture approximately 90% of oxidized Hg because it is highly soluble, but will not remove elemental Hg. However, re-emission of Hg is possible in some circumstances when Hg precipitates out in scrubber solids (mercuric sulfide or equivalent) and the scrubber slurry converts some of the oxidized Hg back into elemental form. Re-emission of elemental Hg can be mitigated through the use of a sulfide-donating liquid reagent additive that enhances the Hg capture within the WFGD by decreasing soluble Hg in the WFGD slurry. Testing would be required to determine the amount of re-emission currently occurring based on recent operating conditions.

3.3. MERCURY EMISSIONS SUMMARY

Presently, there is not any publicly available information to determine if improvements to any of the above categories (individually or in combination) can achieve a Hg emission of 1.2 lb/TBtu or below on a lignite unit.

[5] It should be noted that this approach is patented by Alstom, and use of this approach would need to consider intellectual property implications.

Therefore, additional testing would be required to establish if it is feasible to achieve a 1.2 lb/TBtu Hg emission rate with sufficient operating margin on a lignite unit and if so, develop an overall Hg compliance approach that likely would consist of a suite of control approaches to achieve this rate on MRY Unit 2.

In summary, additional testing would include, but not be limited to, the following:

- Hg speciation data upstream of the ESP, upstream of the WFGD and at the stack (with no controls, current operation and maximum capacity of existing Hg control equipment, and test conditions for other listed items)
- Performance with increased concentrations of current fuel additive system, including additional injection locations, as well as potentially testing other halogen-based fuel additives than what is currently used.
- Performance with halogenated PAC, considering capabilities of existing Hg control equipment and increased injection rates (while also considering other test conditions for other listed items). Note that due to the limitations of the existing equipment, a separate test skid will be required to facilitate this testing campaign.
- If WFGD re-emission is determined to be occurring based on Hg speciation upstream and downstream of the WFGD, the performance of a re-emission additive can also be tested.

As mentioned previously, PAC suppliers have indicated that testing would be required in order to obtain any guaranteed performance. Therefore, recommended consumption and/or injection rates to determine the modifications and/or new systems required are not available at this time to develop the subsequent cost of the suite of Hg controls needed to achieve adequate operating margin below a 1.2 lb/TBtu Hg emission limit on MRY Unit 2.

4. SUMMARY

The existing MRY Unit 2 PM and Hg control technologies were found to not be capable of achieving the proposed emissions included in the April 24, 2023, MATS rule: filterable PM emissions limit of 0.010 lb/MMBtu and potentially 0.006 lb/MMBtu and Hg emissions limit of 1.2 lb/TBtu.

The evaluation of available PM control technologies found that an ESP rebuild would be required to achieve the proposed PM emission limit of 0.010 lb/MMBtu considering the need for adequate operating margin. However, testing to determine the baseline ESP inlet flow profile, ESP inlet and outlet emissions, and amount of PM removal occurring across the WFGD will likely be required in order for a vendor to complete a detailed qualitative study required to provide a PM emission guarantee. A baghouse will likely not provide sufficient operating margin for compliance with the more stringent 0.006 lb/MMBtu proposed emission limit; furthermore, this alternative was not considered to be economically feasible, and OEMs may not offer a PM emission guarantee with sufficient operating margin. A significant outage will be required to complete an ESP rebuild on MRY Unit 2, likely requiring the unit to be offline 12 weeks or longer as part the retrofit. Due to current post-pandemic market delays and the limited number of experienced OEMs capable of completing an ESP rebuild, it is highly likely that the implementation of this large-scale capital project will take longer than the estimated 36-month implementation schedule.

At the time of this evaluation, no evidence or examples demonstrating that an operating lignite unit could achieve the proposed Hg emission limit of 1.2 lb/TBtu were found. As the Hg content of the lignite coal fired at MRY Unit 2 can range from as low as 4.8 lb/TBtu to as high as 17.4 lb/TBtu, a wide range of flexibility in Hg control to account for instances of firing high Hg seams of coal to consistently achieve adequate operating margin below the proposed Hg emission limit will be required. Additional testing will also be required to navigate the challenges of Hg speciation, flue gas temperature, flow profile/mixing, residence time, and coal variability for application on a lignite fired unit to establish if it is feasible to achieve a 1.2 lb/TBtu Hg emission rate with sufficient operating margin. Furthermore, PAC suppliers have indicated that testing would be required in order to obtain any guaranteed performance. Once testing is completed, recommended consumption/injection rates, required flexibility of the suite of Hg control approaches and the subsequent costs of the modifications and/or new systems required to achieve adequate operating margin below a 1.2 lb/TBtu Hg emission limit on MRY Unit 2 can be developed.

ATTACHMENT F

INDUSTRIAL COMMISSION OF NORTH DAKOTA

NORTH DAKOTA TRANSMISSION AUTHORITY

Analysis of

Proposed EPA MATS Residual Risk and Technology Review and

Potential Effects on Grid Reliability in North Dakota

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North Dakota Transmission Authority

April 3, 2024

Assisted by:

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Center of the American Experiment

Contents

Executive Summary

On behalf of the North Dakota Transmission Authority (NDTA), the Center of the American Experiment prepared this study to analyze the potential impacts of EPA's proposed revisions to the Mercury and Air Toxics Standards (MATS) Rule on North Dakota's power generation and power grid reliability.

Our primary finding, which is drawn substantially from the Rule's administrative record, is that the proposed changes are likely not technologically feasible for lignite-based power generation facilities, will foreseeably result in the retirement of lignite power generation units, and will negatively impact consumers of electricity in the Midcontinent Independent Systems Operator (MISO) system by reducing the reliability of the electric grid and increasing costs for ratepayers.

Our analysis builds upon grid reliability data and forecasts from the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC), and it assesses what is likely to happen to grid reliability if the MATS Rule forces some or all of North Dakota's lignite power generation units to retire. We determined that the closure of lignite-fired powered power plants in the MISO footprint would increase the severity of projected future capacity shortfalls, i.e. rolling blackouts, in the MISO system even if these resources are replaced with wind, solar, battery storage, and natural gas plants. In reaching that determination, we have accepted EPA's estimates for capacity values of intermittent and thermal resources.

Moreover, building such replacement resources would come at a great cost to MISO ratepayers. The existing lignite facilities are largely depreciated assets that generate large quantities of dispatchable, low-cost electricity. Replacing these lignite facilities with new wind, solar, natural gas, and battery storage facilities would cost an additional $1.9 billion to $3.8 billion through 2035, compared to operating the current lignite facilities under status quo conditions.

MISO residents would also suffer economic damages from the increased severity of rolling blackouts. Accounting for projected increases in demand for electricity, we assess that if the MATS Rule goes into effect in the near future, by 2035, the MISO grid will experience up to an additional 73,699 megawatt hours (MWh) of unserved load, with an economic cost of up to $1.05 billion based on the Value of Lost Load (VoLL) criteria, which can be thought of as the Social Cost of Blackouts.

Section A: North Dakota's Power Environment

North Dakota Transmission Authority (NDTA)

The North Dakota Transmission Authority (NDTA) was established in 2005 by the North Dakota Legislative Assembly at the behest of the North Dakota Industrial Commission. Its primary mandate is to facilitate the growth of transmission infrastructure in North Dakota. The Authority serves as a pivotal force in encouraging new investments in transmission by aiding in facilitation, financing, development, and acquisition of transmission assets necessary to support the expansion of both lignite and wind energy projects in the state.

Operating as a 'builder of last resort,' the NDTA intervenes when private enterprises are unable or unwilling to undertake transmission projects on their own. Its membership, as stipulated by statute, comprises the members of the North Dakota Industrial Commission, including Governor, Attorney General, and Agriculture Commissioner.

Statutory authority for the North Dakota Transmission Authority (NDTA) is enshrined in Chapter 17-05 of the North Dakota Century Code. Specifically, Section 17-05-05 N.D.C.C. outlines the powers vested in the Authority, which include:

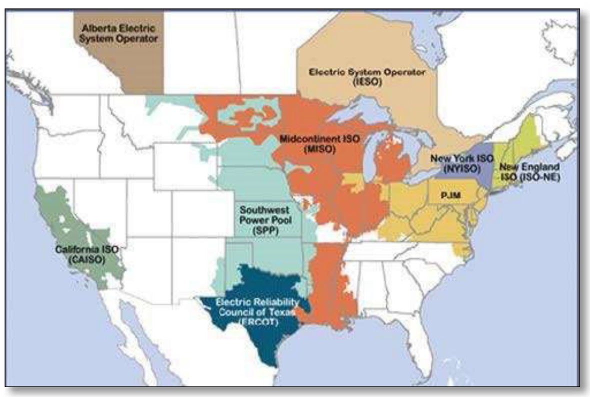
1. Granting or loaning money.
2. Issuing revenue bonds, with an upper limit of $800 million.
3. Entering into lease-sale contracts.
4. Owning, leasing, renting, and disposing of transmission facilities.
5. Entering contracts for the construction, maintenance, and operation of transmission facilities.
6. Conducting investigations, planning, prioritizing, and proposing transmission corridors.
7. Participating in regional transmission organizations.

In both project development and legislative initiatives, the North Dakota Transmission Authority (NDTA) plays an active role in enhancing the state's energy export capabilities and expanding transmission infrastructure to meet growing demand within North Dakota. Key to its success is a deep understanding of the technical and political complexities associated with energy transmission from generation sources to end-users. The Authority conducts outreach to existing transmission system owners, operators, and potential developers to grasp the intricacies of successful transmission infrastructure development. Additionally, collaboration with state and federal officials is essential to ensure that legislation and public policies support the efficient movement of electricity generated from North Dakota's abundant energy resources to local, regional, and national markets.

As the energy landscape evolves with a greater emphasis on intermittent generation resources, transmission planning becomes increasingly intricate. Changes in the generation mix and the redistribution of generation resource locations impose strains on existing transmission networks, potentially altering flow directions within the network. A significant aspect of the Authority's responsibilities involves closely monitoring regional transmission planning efforts. This includes observing the activities of regional transmission organizations (RTOs) recognized by the Federal Energy Regulatory Commission (FERC), which oversee the efficient and reliable operation of the transmission grid. While RTOs do not own transmission assets, they facilitate non-discriminatory access to the electric grid, manage congestion, ensure reliability, and oversee planning, expansion, and interregional coordination of electric transmission.

Many North Dakota service providers are participants in the Midcontinent Independent System Operator (MISO), covering the territories of several utilities and transmission developers. Additionally, some entities are part of the Southwest Power Pool (SPP), broadening the scope of transmission planning. Together, North Dakota utilities and transmission developers contribute to a complex system overseeing the transmission of over 200,000 megawatts of electricity across 100,000 miles of transmission lines, serving homes and businesses in multiple states.

MISO and SPP also operate power markets within their respective territories, managing pricing for electricity sales and purchases. This process determines which generating units supply electricity and provide ancillary services to maintain voltage and reliability. Overall, the NDTA's involvement in regional transmission planning and coordination is crucial for ensuring the reliability, efficiency, and affordability of electricity transmission across North Dakota and beyond.



FERC-Recognized Regional Transmission Organizations and Independent System Operators

(www.ferc.gov)

Generation Adequacy, Transmission Capacity & Load Forecast Studies

The North Dakota Transmission Authority (NDTA) conducts periodic independent evaluations to assess the adequacy of transmission infrastructure in the state. In 2023, the NDTA commissioned two generation resource adequacy studies, one for the Midcontinent Independent System Operator (MISO) and another for the Southwest Power Pool (SPP). Additionally, the NDTA recently completed a generation resource adequacy study examining the impact of the EPA's proposed Mercury and Air Toxics Standards (MATS) Rule. A transmission capacity study commissioned by the NDTA is scheduled for completion in the summer of 2024.

Regular load forecast studies are also commissioned by the NDTA, with the most recent study completed in 2021. This study, conducted by Barr Engineering, provided an update to the Power Forecast 2019, projecting energy demand growth over the next 20 years. The 2021 update incorporates factors such as industries expressing interest in locating in North Dakota, abundant natural gas availability from the Bakken wells, and the potential for carbon capture and sequestration from various sources. The 2021 update and the full study can be obtained from the North Dakota Industrial Commission website: Power Forecast Study – 2021 Update, https://www.ndic.nd.gov/sites/www/files/documents/Transmission-Authority/Publications/ta-annualreport-21.pdf

The Power Forecast 2021 Update projects a 10,000 GWhr increase in energy demand over the next two decades under the consensus scenario, requiring approximately 2200 to 2500 MW of additional capacity to meet demand. These projections are closely tied to industrial development forecasts and are coordinated with forecasts used by the North Dakota Pipeline Authority. These projections were highly dependent on industrial development and are premised on new federal regulations not forcing the early retirement of even more electric generation units.

Meeting this growing demand poses significant challenges for utilities responsible for providing reliable service. While there is considerable interest in increasing wind and solar generation, natural gas generation is also essential to provide stability to weather-dependent renewable sources. Importantly, load growth across the United States is driven by the electrification of transportation, heating/cooling systems, data centers, and manufacturing initiatives.

Studies consistently highlight the critical importance of maintaining existing dispatchable generation to prevent grid reliability failures. Ensuring uninterrupted power supply is paramount for national security, public safety, food supply, and overall economic stability. The NDTA's ongoing assessments and proactive planning are crucial for meeting the evolving energy needs of North Dakota while maintaining grid reliability and resilience.

The timing and implementation of resources to meet this growing demand is a significant challenge for the utilities. Importantly, electric demand growth across the United States over the next several decades is projected to be dramatic due to the electrification of transportation, home heating/conditioning, data center and artificial intelligence centers, as well as the effort to bring manufacturing back to the USA. Studies by NDTA and others all point to the critical need to keep all existing dispatchable generation online to avoid catastrophic grid reliability failures, and have been warning that the push to force the retirement of reliable, dispatchable fossil fuel generation units is occurring before it is projected there will be sufficient intermittent units in place to cover the anticipated increase in demand. And when demand for electricity exceeds the dispatchable supply, the foreseeable result will be blackouts or energy rationing.

Current North Dakota Generation Resources

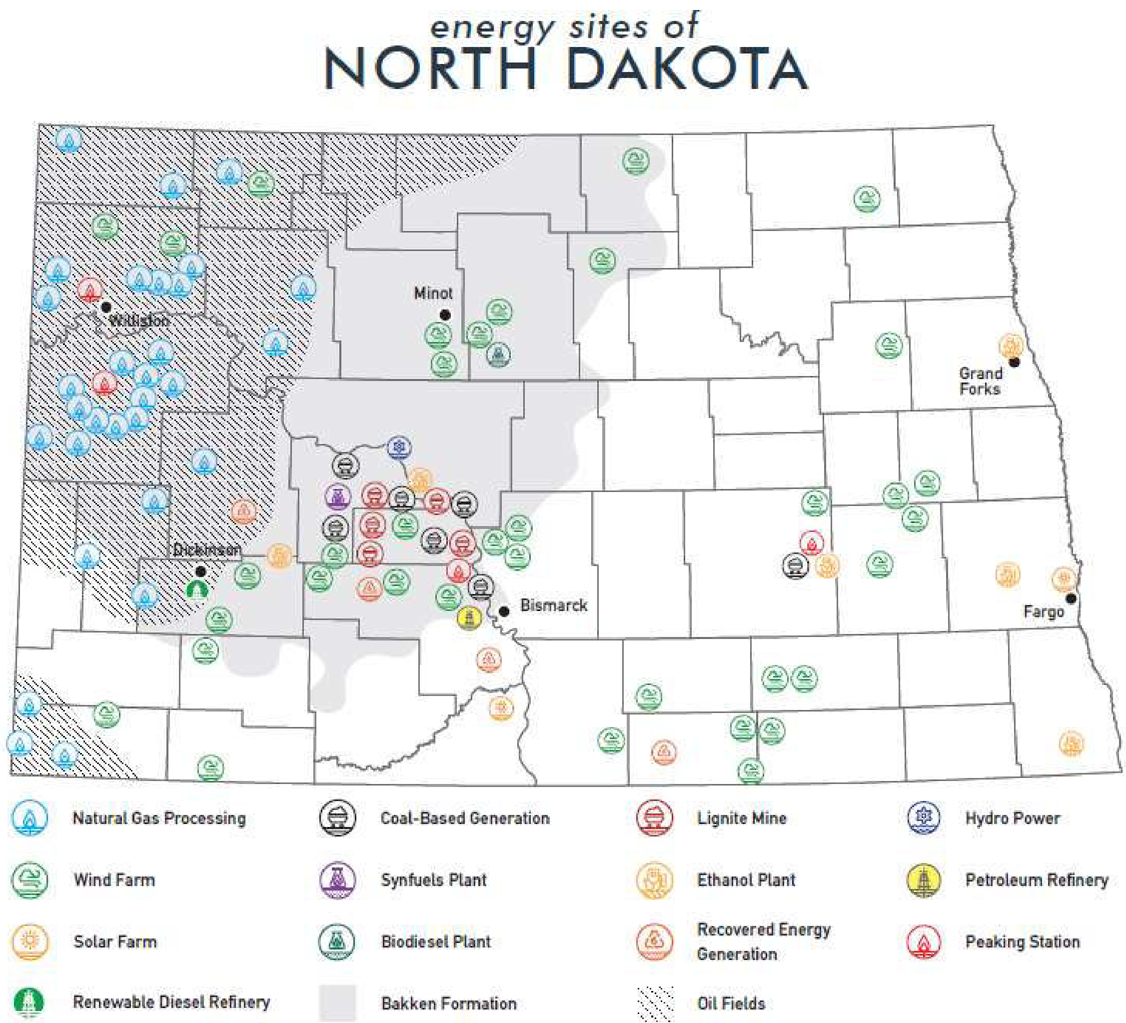
Here is the current breakdown of North Dakota's generation resources:

1. Renewable Generation:
    - Wind Generation: North Dakota has 4,250 MW of wind generation capacity in service, making it a significant contributor to the state's renewable energy portfolio. The average capacity factor for these generating facilities is 40% to 42%.
    - The 4,000 MW of wind generation receives a reduced capacity accreditation in the ISO of approximately 600 MW since it is intermittent. This is representative of the

amount that is estimated to be available for the peak demand in the summer.
- Solar Generation: Although North Dakota currently lacks utility-scale solar generation facilities in operation, some projects are in the queues of regional transmission organizations like MISO and SPP, indicating potential future development in this area.

2. Thermal Coal Generation:
   - North Dakota currently operates thermal coal generation at six locations, comprising a total of 10 generating units with a combined capacity of approximately 4,048 MW.
   - The average capacity factor for these generating plants ranged from 65% to 91% in 2021, excluding the retired Heskett Station.
   - Rainbow Energy operates the Coal Creek Station and the DC transmission line that transports ND produced energy to the Minneapolis region. Rainbow Energy is assessing a CO_2 capture project for the facility. In addition, approximately 400 MW of wind generation is planned for that area of McLean County to utilize the capacity on the DC line.
3. Hydro Generation:
   - North Dakota has one hydro generation site equipped with 5 units, boasting a total capacity of 614 MW.
   - However, the average capacity factor declined to approximately 43% in 2021 due to limitations imposed by water flow in the river, particularly during drought years.
4. Natural Gas Generation:
   - North Dakota operates three sites for electric generation utilizing natural gas, comprising 21 generating units with a total capacity of 596.3 MW.
   - These units include reciprocating engines and gas turbines, with variation in summer capacity influenced by the performance of gas generators in hot weather.
   - Total natural gas generation in North Dakota remained steady from 2019 through 2021, amounting to 1.445 GWhr in 2021.
5. Total Generation:
   - The combined total capacity of all types of utility-scale generation in North Dakota is approximately 8,863 MW.
   - Wind generation receives a reduced capacity accreditation in the ISO of approximately 600 MW due to its intermittent nature, down from 4,250MW of installed capacity, representing the estimated amount available during peak summer demand. However, newer installations have demonstrated slightly higher capacity for accreditation.

This comprehensive overview underscores the diverse mix of generation resources in North Dakota, with significant contributions from wind, coal, hydro, and natural gas. Continued assessment and adaptation to evolving energy needs and market dynamics are essential for ensuring a reliable and sustainable energy future for the state.



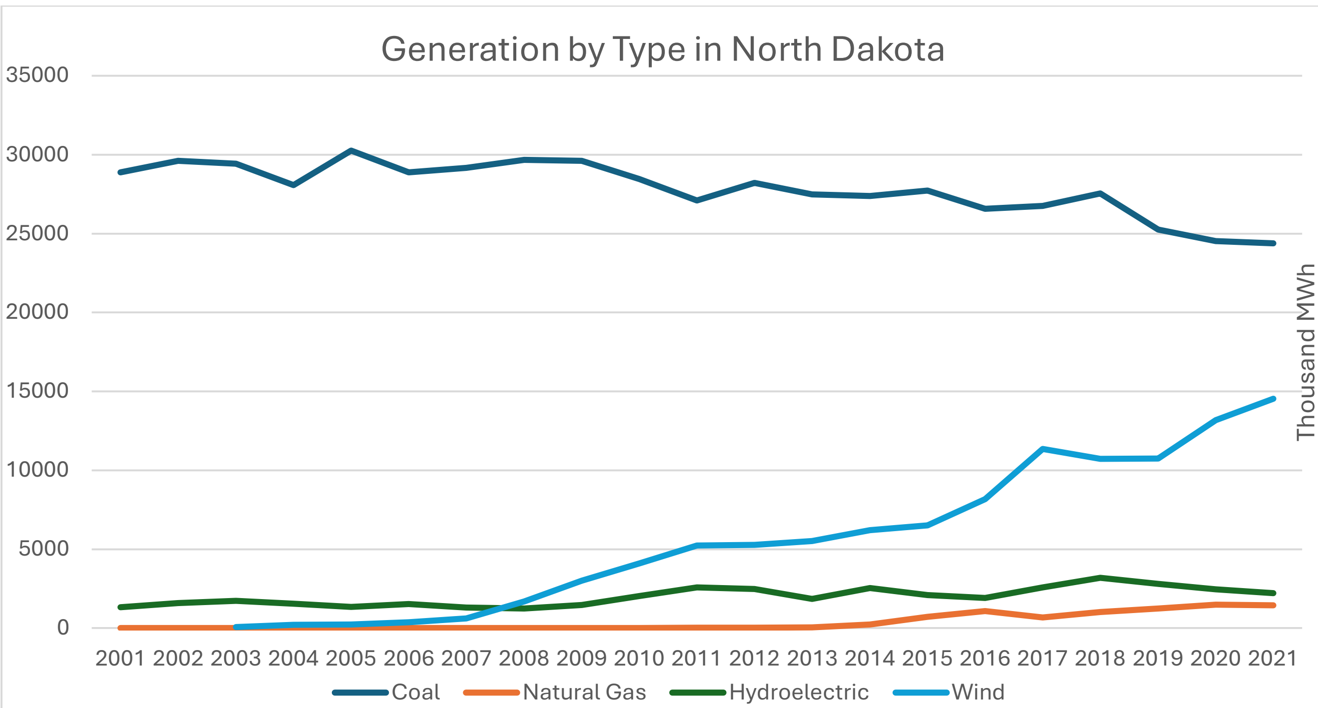
+ *Map courtesy of Bismarck State College National Energy Center of Excellence.*

Electric Generation Market & Utilization

In recent decades, North Dakota has emerged as a significant exporter of electricity, primarily fueled by the development of thermal lignite generation in the western part of the state since the 1960s. Concurrently, transmission infrastructure has been expanded to facilitate the export of electricity to markets predominantly situated to the east. Moreover, North Dakota has garnered recognition as an excellent source of wind generation, leading to additional transmission development to accommodate the transmission of this renewable energy to markets.

According to data from the Energy Information Administration, in 2020, North Dakota generated a total of 42,705 MWh of electricity from all sources, with 46% of this total being exported beyond the state's borders over two large high voltage direct current lines (HVDC), which serve load in the neighboring state of Minnesota and multiple 345kv and 230kv alternating current (AC) transmission lines serving surrounding states. Wind generation accounted for 31% of North Dakota's total electricity generation in 2020, highlighting the growing significance of renewable energy in the state's energy portfolio. Notably, industrial demand in North Dakota experienced substantial growth, expanding by nearly 11% in 2020.

While demand for electricity in markets outside of North Dakota, and in most areas within the state, has remained relatively stable in recent years, the Bakken region has witnessed notable demand growth. Over the past 16 years, total electricity generation in North Dakota has increased from 29,936 MWh to 42,705 MWh, with retail sales climbing from 10,516 MWh to 22,975 MWh. This growth is primarily attributed to the burgeoning development of the Bakken oil fields. Industrial consumption in North Dakota also witnessed a robust increase of over 11% in 2020, with power forecasts projecting a continued upward trajectory in demand.



Grid Resource Adequacy and Threats to Growth Opportunities

In 2023, both the MISO and SPP grid operators issued warnings about the adequacy of generation resources to meet peak demand situations. This highlights a growing concern that the desired pace of change towards a more sustainable energy future is outpacing the achievable pace of transformation. This concern is underscored by the stark increase in grid events necessitating the activation of emergency procedures. **For instance, prior to 2016, MISO had no instances requiring the use of emergency procedures, but since then, there have been 48 Maximum Generation events.**

Many experts in the industry project that, despite ambitious goals, realistic scenarios still foresee a substantial dependence on fossil fuel energy—potentially up to 50%—even by 2050. While efforts to decarbonize fossil fuel resources are underway, achieving complete carbon neutrality or a fully renewable energy grid by 2050 appears increasingly unlikely. The scalability and affordability of storage technology, particularly for renewable energy sources, remain significant challenges.

In response to these challenges, Governor Burgum has issued a visionary goal for North Dakota to achieve carbon neutrality in its combined energy and agriculture sectors by 2030. Governor Burgum's approach emphasizes innovation over mandates, aiming to attract industries and technologies that support this goal to the state. The initiative seeks to leverage advancements in carbon capture and sequestration technologies to retain conventional generation in North Dakota while also promoting sustainable agricultural practices and other innovative solutions, such as CO2 sequestration from ethanol production and enhanced oil recovery. These efforts demonstrate a commitment to proactive and pragmatic solutions to address the complexities of achieving carbon neutrality in the energy and agriculture sectors.

The state's vision for a decarbonized energy generation future faces significant challenges due to the individual and cumulative impact of expansive federal rulemakings. These regulations would curtail the flexibility to achieve the 2030 goal through the deployment of carbon capture and sequestration (CCS) technologies. Furthermore, they would impose financial burdens on electric cooperatives and utilities with limited resources, diverting investment away from future growth options toward retrofitting existing facilities with costly emissions technologies to comply with new federal requirements.

This regulatory burden not only impedes progress towards decarbonization but also introduces opportunity costs for utilities and cooperatives. The funds that would otherwise be allocated for future growth and innovation in clean energy solutions are instead diverted to compliance measures, hindering the state's ability to transition to a more sustainable energy future efficiently and effectively.

Ultimately, the restrictive nature of these federal rulemakings poses a significant obstacle to North Dakota's efforts to achieve its decarbonization goals and undermines the state's vision for a cleaner and more sustainable energy generation landscape. It highlights the need for a balanced approach to regulation that supports innovation and investment in carbon reduction technologies while also allowing for continued economic growth and development in the energy sector.

Grid Reliability Is Already Vulnerable

The fragility of grid reliability is already evident as warnings have been issued due to the declining ratio of dispatchable and intermittent generation supplies. This concerning trend poses significant threats to public safety, economic stability, and national security. Grid reliability is vital for ensuring continuous access to essential services, such as food production and military operations. Dispatchable reliable generation forms the backbone of grid stability, enabling the balancing of supply and demand fluctuations. Failure to address these reliability concerns will compromise critical infrastructure and expose society to substantial risks. Urgent action is required to safeguard grid reliability and mitigate the potential consequences for public safety and national security.

NERC's 2023 Reliability Risk Assessment

The North American Electric Reliability Council's 2023 Reliability Risk Assessment[1] are concerning as demonstrated in the slides below. The electrification of the US economy, data & AI center growth and the build it at home initiatives will substantially increase the demand for electricity generation and transmission.

NERC's 2023 Summer Reliability Assessment warns that two-thirds of North America is at risk of energy shortfalls this summer during periods of extreme demand. While there are no high-risk areas in this year's assessment, the number of areas identified as being at elevated risk has increased. The assessment finds that, while resources are adequate for normal summer peak demand, if summer temperatures spike, seven areas — the U.S. West, SPP and MISO, ERCOT, SERC Central, New England and Ontario — may face supply shortages during higher demand levels.

"Increased, rapid deployment of wind, solar and batteries have made a positive impact," said Mark Olson, NERC's manager of Reliability Assessments. "However, generator retirements continue to increase the risks associated with extreme summer temperatures, which factors into potential supply shortages in the western two-thirds of North America if summer temperatures spike."

The North American Electric Reliability Corporation (NERC) recently released its 2023 Long-Term Reliability Assessment (LTRA), which found MISO is the region most at risk of capacity shortfalls in the years spanning from 2024 to 2028 due to the retirement of thermal resources with inadequate reliable generation coming online to replace them.[2]

[1] NERC. "North American Reliability Assessment." North American Electric Reliability Corporation, May 2023, https://www.nerc.com/news/Headlines%20DL/Summer%20Reliability%20Assessment%20Announcement%20May%202023.pdf.

[2] North American Electric Reliability Corporation, "2023 Long-Term Reliability Assessment," December, 2023, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

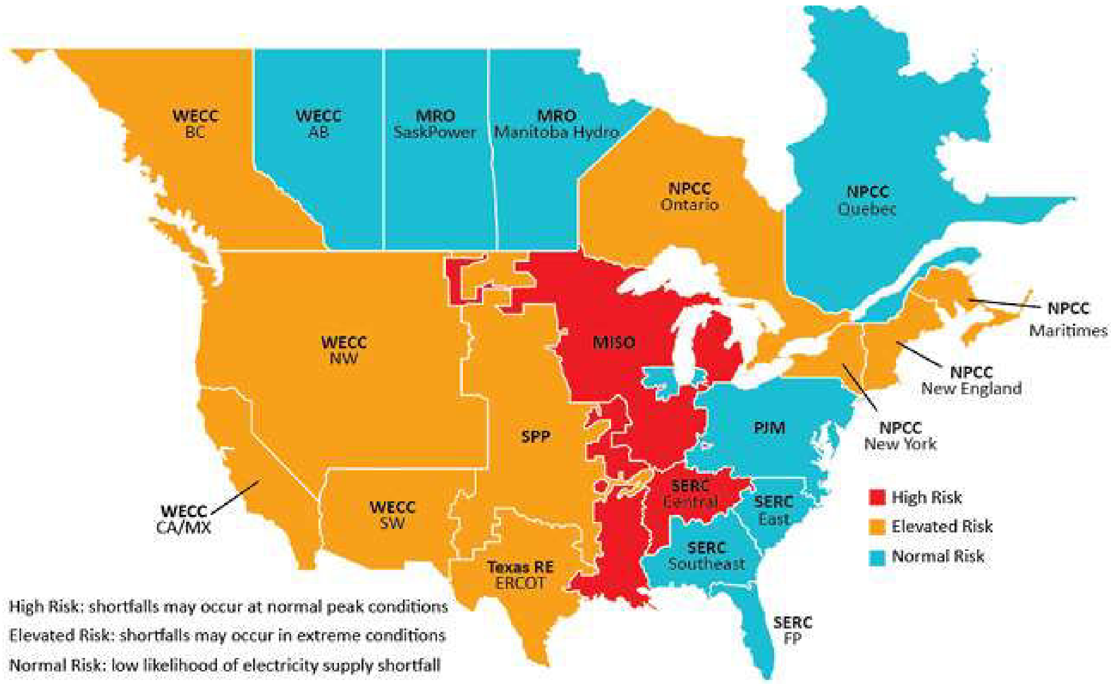


Figure 1: Risk Area Summary 2024–2028[8]

MISO is the region most at risk of rolling blackouts in the near future.

In 2028, MISO is projected to have a 4.7 GW capacity shortfall if expected generator retirements occur despite the addition of new resources that total over 12 GW, leaving MISO at risk of load shedding during normal peak conditions. This is because the new wind and solar resources that are being built have significantly lower accreditation values than the older coal, natural gas, and nuclear resources that are retiring.[3]

MISO's Response to the Reliability Imperative (2024)

On February 26, 2024, the Midcontinent Independent System Operator (MISO) released "MISO's Response to the Reliability Imperative[4]," a report which is updated periodically to reflect changing conditions in the 15-state MISO region that extends through the middle of the U.S. and into Canada. MISO's new report explains the disturbing outlook for electric reliability in its footprint unless urgent action is taken. The main reasons for this warning are the pace of premature retirements of dispatchable fossil generation and the resulting loss of accredited capacity and reliability attributes.

From 2014 to 2024, surplus reserve margins in MISO have been exhausted through load growth and unit retirements. Since 2022, MISO has been operating near the level of minimum reserve

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[3] Midcontinent Independent Systems Operator, "MISO's Response to the Reliability Imperative," February, 2024, https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.

[4] MISO. "MISO'S Response to the Reliability Imperative Updated February 2024." MISO, February 2024, https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.

margin requirements.[5]

According to the Reliability Imperative, MISO uses an annual planning tool called the OMS-MISO Survey to compile information about new resources utilities and states plan to build and older assets they intend to retire. The 2023 survey shows the region's level of "committed" resources declining going forward, with a potential shortfall of 2.1 GW occurring as soon as 2025 and growing larger over time.

MISO lists U.S. Environmental Protection Agency (EPA) regulations that prompt existing coal and gas resources to retire sooner than they otherwise would as a compounding reason for growing challenges to grid reliability. From the report, there is a section titled, "EPA Regulations Could Accelerate Retirements of Dispatchable Resources," which states:

> *"While MISO is fuel- and technology-neutral, MISO does have a responsibility to inform state and federal regulations that could jeopardize electric reliability.* ***In the view of MISO, several other grid operators, and numerous utilities and states, the U.S. Environmental Protection Agency (EPA) has issued a number of regulations that could threaten reliability in the MISO region and beyond.***
>
> *In May 2023, for example, EPA proposed a rule to regulate carbon emissions from all existing coal plants, certain existing gas plants and all new gas plants. As proposed, the rule would require existing coal and gas resources to either retire by certain dates or else retrofit with costly, emerging technologies such as carbon-capture and storage (CCS) or co-firing with low-carbon hydrogen.*
>
> *MISO and many other industry entities believe that while CCS and hydrogen co-firing technologies show promise, they are not yet viable at grid scale — and there are no assurances they will become available on EPA's optimistic timeline.* ***If EPA's proposed rule drives coal and gas resources to retire before enough replacement capacity is built with the critical attributes the system needs, grid reliability will be compromised.*** *The proposed rule may also have a chilling effect on attracting the capital investment needed to build new dispatchable resources*."

Despite these reliability warnings issued by MISO, EPA did not consider the reliability impacts of the proposed MATS rules required emission control upgrades and additions to units. It is likely that many units that would have to incur millions of dollars to retrofit emissions controls to comply with this proposal would not do so.[6]

In light of these shortcomings, the NDTA contracted with Center of the American Experiment to model the impacts of the MATS rules on resource adequacy, reliability, and cost of electricity to consumers. The findings of this analysis are detailed in Section D.

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[5] Midcontinent Independent Systems Operator, "MISO's Response to the Reliability Imperative," February, 2024, https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.

[6] Rae E. Cronmiller, "Comments on Proposed National Emission Standards for Hazardous Air Pollution: Coal-and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review," The National Rural Electric Cooperative Association, June 23, 2023, Attention Docket ID NO. EPA-HQ-OAR-2018-0794.

Conclusion: The Long Term Reliability of the MISO Grid is Already Precarious

As the state agency responsible for the strategic buildout and framework of electricity distribution, the North Dakota Transmission Authority (NDTA) is deeply concerned about the potential impact of federal rulemakings on the generation fleet in North Dakota and the ability to support future growth initiatives. The current strain on the electric transmission system due to load growth is already posing significant challenges to grid reliability, particularly in areas facing transmission constraints and limited access to dispatchable generation.

The escalating frequency of grid events requiring emergency procedures, such as the 48 Maximum Generation events in MISO since 2016 and the increasing number of alerts issued by SPP, over 194 alerts issued in 2022, underscores the urgency of addressing transmission congestion and bolstering reliable generation capacity. The economic growth and security of North Dakota are directly tied to the timely development of new transmission facilities in tandem with dependable dispatchable electric generation.

The impacts of grid strain extend beyond the energy sector, affecting multiple industries, ratepayers, and overall economic stability. Volatile wholesale prices and transmission congestion undermine business operations and investment confidence, hindering economic growth and prosperity. Moreover, reliable electricity supply is critical for essential services, including Department of Defense facilities, underscoring the broader implications of grid reliability issues. Achieving a balanced generation portfolio requires careful consideration of reliability and resilience under all weather conditions, especially amidst the electrification of America and the imperative to safeguard public welfare and security.

Additionally, over 50% of the electricity generated in North Dakota is exported to neighboring states, magnifying the ripple effects of any regulations impacting dispatchable electricity generation resources. By responsibly managing the generation portfolio and prioritizing generation adequacy, North Dakota and the nation can seize significant opportunities for economic growth, innovation, and sustainable development.

Section B: The Proposed MATS Rule Will Dramatically Affect North Dakota Lignite Electric Generating Units

The revised MATS Rule includes a proposal to eliminate the “low rank coal” subcategory established for lignite-powered facilities by requiring these facilities to comply with the same mercury emission limitation that currently applies to Electric Generating Units (EGUs) combusting bituminous and subbituminous coals, which is 1.2 pounds per trillion British thermal units of heat input (lb/TBtu). EPA’s proposal is a substantial lowering of the current mercury limitation for lignite fired EGUs, which is 4.0 lb/TBtu.[7,8] The proposal also includes a significant reduction in the particulate matter standard applicable to all existing units from 0.03 lb/mmBtu to 0.01 lb/mmBtu. Because North Dakota is somewhat unique to the degree in which its power generation relies upon lignite coal, the compliance costs for this Rule, while likely to substantial for coal plants all around the country, will be most acutely inflicted upon North Dakota's lignite-based power generation facilities.

Numerous comments in the administrative record, including from the regulated facilities in North Dakota and the North Dakota Department of Environmental Quality, provided EPA with notice that the new emission standards are not technologically feasible, will impose crippling compliance costs that may require facility retirement, and will result in a significant portion of the dispatchable power provided by coal-generation facilities being taken off the grid. This report will summarize some of those concerns in the section that follows, however, a full study of the technological feasibility of complying with the new emissions standards is beyond the scope of this report. For purposes of this report, we assume the regulated facilities and state regulator were forthright in their concerns about the feasibility of lignite-based facilities meeting the new standards.

The Proposed MATS Rule Eliminates the Lignite Subcategory for Mercury Emissions

Although the Proposed Rule affects all coal electrical generating utilities (EGUs), reducing the lignite emissions standards to levels of other coal ranks effectively eliminates the lignite sub-category and would have drastic consequences for North Dakota's lignite EGU industry.[9] EPA original decision to regulate separately a subcategory of lignite units was well-supported with documented information and a thorough analysis. In its comments filed in this Docket, on June 22, 2023, the North Dakota Department of Environmental Quality (hereafter DEQ) encouraged EPA to review that prior determination and reaffirm the need for a lignite subcategory and the associated emissions standards.[10]

Specifically, DEQ summarized the original MATS proposal in 2011 and final MATS rule in 2012, in which EPA presented a body of evidence in support of the lignite category. For example, the EPA wrote:

> "For Hg emissions from coal-fired units, we have determined that different emission limits for the two subcategories are warranted. There were no EGUs designed to burn a non-agglomerating virgin coal having a calorific value (moist, mineral matter free

[7] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[8] [8] J. Cichanowicz et al., *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology*, (June 2, 2023) ("Cichanowicz Report").

[9] EPA characterizes lignite as "low rank virgin coal". 88 Fed. Reg. 24,854, 24,875. For this comment letter, lignite will be used in place of low rank virgin coal.

[10] David Glatt, P.E., "Comments on the Proposed Rulemaking Titled "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review" (Docket ID No. EPA-HQOAR-2018-0794)," On Behalf of the North Dakota Department of Environmental Quality, June 22, 2023.

> basis) of 19,305 kJ/kg (8,300 Btu/lb) or less in an EGU with a height-to-depth ratio of 3.82 or greater among the top performing 12 percent of sources for Hg emissions, indicating a difference in the emissions for this HAP from these types of units.
>
> The boiler of a coal-fired EGU designed to burn coal with that heat value is larger than a boiler designed to burn coals with higher heat values to account for the larger volume of coal that must be combusted to generate the desired level of electricity. Because the emissions of Hg are different between these two subcategories, we are proposing to establish different Hg emission limits for the two coal-fired subcategories."

As explained by DEQ, EPA has not provided any scientific justification to support abandoning the lignite subcategory and requiring those facilities to comply with the emission standards applicable to other coal types. The most EPA identified in support of its proposal was a reference to information nearly 30 years old, which predated EPA's original determination.

The Proposed MATS Rule Will Not Provide Meaningful Human Health or Environmental Benefits

Section 112(f)(2) of the CAA directs EPA to assess the remaining residual public health and environmental risks posed by hazardous air pollutants (HAPs) emitted from the EGU source category.[11] Further regulation under MATS is required only if that residual risk assessment demonstrates that a tightening of the current HAP emission limitations is necessary to protect public health with an ample margin of safety or protect against adverse environmental effects.

When reviewing whether to revise the MATS Rule, EPA determined that further regulation of mercury and other HAPs would be unnecessary to address any remaining residual risk from any affected EGU within the source category. The stringent standards based on state-of-the-art control technologies that are currently imposed on coal-fired EGUs have already achieved significant reductions in HAP emissions. As EPA itself noted, the MATS rule has achieved steep reductions in HAP emission levels since 2010, including a 90 percent reduction in mercury, 96 percent reduction in acid gas HAPs, and an 81 percent reduction in non-mercury metal HAPs.[12]

Data from EPA and the U.N Global Mercury Assessment show mercury emissions from U.S. power plants are now so low they accounted for only 0.12 percent of global mercury emissions in 2022, assuming all other sources remained constant at 2018 levels.[13] These data demonstrate that

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[11] J. Cichanowicz et al., *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology*, at 29, Figure 6-7 (June 2, 2023) ("Cichanowicz Report").

[12] Fact Sheet, *EPA's Proposal to Strengthen and Update the Mercury and Air Toxics Standards for Power Plants,* https://www.epa.gov/system/files/documents/2023-04/Fact%20Sheet_MATS%20RTR%20Proposed%20Rule.pdf

[13] United Nations, "Global Mercury Assessment 2018," UN Environment Programme, August 21, 2019, https://wedocs.unep.org/bitstream/handle/20.500.11822/27579/GMA2018.pdf?sequence=1&isAllowed=y

US mercury emissions from power plants are lower than global cremation emissions, and North Dakota coal facilities emitted 9.25 times less mercury in 2021 than global cremations in 2018.[14]

Mercury Emissions Estimates by Sector 2018 vs U.S. and N.D. Coal Plant Emissions		
Category	US Tons	Percent of Global Emissions
Artisanal and small-scale mining	921.42	37.68
Global stationary combustion of coal	517.45	21.16
Non-ferrous metals production	359.32	14.69
Cement production	256.48	10.49
Waste from products	161.63	6.61
Vinyl chlorine monomer	64.09	2.62
Biomass burning	57.05	2.33
Ferrous metals production	43.89	1.79
Chlor alkali production	16.66	0.68
Waste incineration	16.44	0.67
Oil refining	15.81	0.65
Stationary combustion of oil and gas	7.84	0.32
Cremation	4.14	0.17
US stationary combustion of coal	2.90	0.12
North Dakota coal combustion	0.46	0.018

As the above chart indicates: the annual mercury emissions from global cremations (where the mercury primarily comes from individuals with dental fillings) exceed the mercury annually emitted by all coal-fired EGUs in the United States combined, and is orders of magnitude more than the mercury emissions from all coal-fired EGUs in North Dakota.[15]

Moreover, the Administrative Record indicates EPA has performed a comprehensive and detailed risk assessment that clearly documents the negligible remaining residual risks posed by the very low amount of HAPs now being emitted by coal-fired EGUs. EPA first performed that risk assessment in 2020, which concluded that "both the actual and allowable inhalation cancer risks to the individual most exposed were below 100-in-1 million, which is the presumptive limit of

[14] ERM Sustainability Initiative, "Benchmarking Air Emissions of the 100 Largest Power Producers in the United States," Interactive Tool, accessed February 29, 2024, https://www.sustainability.com/thinking/benchmarking-air-emissions-100-largest-us-power-producers/

[15] UN Environmental Programme. (2018). Global Mercury Report 2018, Technical Background Report to the Global Mercury Assessment. https://www.unenvironment.org/resources/publication/global-mercury-assessment-technical-background-report

acceptability" for protecting public health with an adequate margin of safety.[16] Similarly, EPA's risk assessment supports the conclusion that residual risks of HAP emissions from the EGU source category are "acceptable" for other potential public health effects, including both chronic and acute non-cancer effects.[17]

These conclusions have been confirmed by the detailed reevaluation of the 2020 risk assessment that the Agency is now completing as part of the current rule-making action. That EPA reevaluation clearly demonstrates that the 2020 risk assessment did not contain any significant methodological or factual errors that could call into question the results and conclusions reached in the 2020 risk assessment. Most notably, EPA used well-accepted approaches and methodologies for performing a residual risk analysis that adhere to the requirements of the statute and are consistent with prior residual risk assessments performed by EPA over the years for other industry sectors.[18]

The results from both residual risk assessments can lead to only one rational conclusion: the current MATS limitations provide an ample margin of safety to protect public health in accordance with CAA section 112.

The DEQ filed comments addressing these points and asking EPA to provide a better health benefit justification than the rationale currently included in the Regulatory Impacts Analysis (RIA).[19] In particular, DEQ noted that EPA cannot rely on non-HAPs' co-benefits to justify the Proposed Rule, and EPA has not identified any HAP-related benefits that would be sufficient to justify the Proposed Rule. The agency also voiced skepticism over what it called EPA' s suspect characterization of the health benefits that it identified, which is quoted below:

> While the screening analysis that EPA completed suggests that exposures associated with mercury emitted from EGUs, including lignite-fired EGUs, are below levels of concern from a public health standpoint, further reductions in these emissions should further decrease fish burden and exposure through fish consumption including exposures to subsistence fishers.[20]

DEQ's well-founded concern is that EPA's admission that current exposure associated with mercury is below levels of concern is directly inconsistent with, not support of, EPA's proposal for a lower standard.

DEQ commented that this theme, unfortunately, is consistent across the entire "Benefits Analysis" section of the RIA, citing another example of this inconsistency, which is quoted below:

> "Regarding the potential benefits of the rule from projected HAP reductions, we note that these are discussed only qualitatively and not quantitatively

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[16] 88 Fed. Reg. at 24,865.
[17] *Id*. at 24,865-66.
[18] 88 Fed. Reg. at 24,865.
[19] Regulatory Impact Analysis for the Proposed National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review (Apr. 2023), Docket ID: EPA-HQ-OAR-2018-0794-5837.
[20] *Id.* At p. 0-8.

> ....Overall, the uncertainty associated with modeling potential of benefits of mercury reduction for fish consumers would be sufficiently large as to compromise the utility of those benefit estimates-though importantly such uncertainty does not decrease our confidence that reductions in emissions should result in reduced exposures of HAP to the general population, including methylmercury exposures to subsistence fishers located near these facilities. Further, estimated risks from exposure to non-mercury metal HAP were not expected to exceed acceptable levels, although we note that these emissions reductions should result in decreased exposure to HAP for individuals living near these facilities."[21]

Comments filed by the Lignite Energy Council (LEC) further emphasize the point. LEC stated that according to the risk review EPA conducted in 2020, which EPA has proposed to reaffirm, the risks from current emissions of hazardous air pollutants (HAP) emitted by coal-fired power plants are several orders of magnitude below what EPA deems sufficient to satisfy the Clean Air Act.[22] LEC points out that EPA has for decades found risks to be acceptable with an ample margin of safety if maximum individual excess cancer risks presented by any single facility is less than "100-in-1 million." In comparison, EPA's analysis of the coal- and oil-fired electric utility source category recognizes the risk it presents is now at one tenth of that acceptable level, with a maximum risk from any individual facility of "9-in-1 million."

However, even that value vastly overstates the risk associated with coal-fired power plants. The "9-in-1 million" risk level identified by EPA is only associated with a single, uncontrolled, residual oil-fired facility located in Puerto Rico.[23] What EPA's discussion of risk fails to recognize, but its analysis clearly shows, is that the highest level of risk presented by any coal-fired power plant is actually "0.3-in-1 million," more than 300 times lower than the threshold EPA deems acceptable.[24]

The level of risk presented by North Dakota lignite-powered plants is lower still. According to EPA's risk review, the maximum risks presented by any North Dakota lignite-fired power plant is "0.08-in-1 million," yet another order of magnitude lower than the highest risk from any coal-fired plant, and more than three orders of magnitude lower than EPA's "acceptable" level of risk with an "ample margin of safety."

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[21] *Id.* at pp. 4-1 - 4-2.

[22] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[23] *Residual Risk Assessment for the Coal- and Oil-Fired EGU Source Category in Support of the 2020 Risk and Technology Review Final Rule*, Docket ID No. EPA-HQ-OAR-2018-0794-4553, App. 10, Tbls. 1 & 2a (Sept. 2019) ("Risk Assessment") (note that Table 2a is printed upside down in the final September 2019 version of the Residual Risk Assessment posted at www.regulations.gov, which may interfere with search commands; a searchable version of the same table is available in the December 2018 draft version, Docket ID No.). *See also* 84 Fed. Reg. at 2699 ("There are only 4 facilities in the source category with cancer risk at or above 1-in-1 million, and all of them are located in Puerto Rico.").

[24] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

The risks from North Dakota lignite are so low that they are more easily expressed, not in a million, but in a ***billion***—EPA has determined that the excess cancer risks from all North Dakota lignite plants fall between 5- and 80-in-1 billion.[25] Moreover, EPA's analysis indicates that those maximum risks are not associated with mercury.[26]

In fact, EPA's own analysis confirms the risks from North Dakota lignite-powered plants are so low they are little more than a rounding error that does not even qualify as a significant digit. In its analysis of the still low but relatively higher risk from the Puerto Rican oil-fired plants, EPA determined that one of those facilities presented a risk no greater than "1-in-1 million," even though EPA's modeling actually returned a risk level of "1.**09**-in-1 million."6 EPA discarded the extra ".09," apparently finding it too small to matter. However, that extra ".09" risk equates to "90-in-1 billion," and it is therefore higher than the ***entire*** risk identified for any North Dakota lignite plant.

The Administrative Record Indicates the Mercury Standard of 1.2 lb./TBtu is Technically Unachievable for EGUs using North Dakota Lignite Coal

The Administrative Record for the proposed rule suggests EPA made numerous critical mistakes in assuming lignite fired EGUs can achieve a 1.2 Hg/lb limit with 90% Hg removal. As detailed in the Cichanowicz Report, Section 6, EPA assumed the characteristics of lignite and subbituminous coals are similar such that the Hg removal by emission controls capabilities is similar. In this light, EPA did not consider that the high presence of sulfur trioxide (SO3) in lignite coal combustion flue gas that significantly limits the Hg emissions reduction potential of emissions controls.[27]

Similarly, as noted by LEC, EPA's proposal references data obtained via an information collection request as indicative of the level of performance achievable at North Dakota lignite facilities, but that data only reflects relatively short-term testing that does not fully capture the significant variability of lignite coals. Also, unlike other types of facilities that may be able to blend coals to achieve greater consistency in the character of their fuel, all North Dakota lignite units are located at mine-mouth facilities without access to other coal types, and therefore depend entirely on the fuel extracted from the neighboring mine. As a result, changes in constituents between seams of lignite coal can result in a high level of variability in the emission rates that result from use of the coal as it is mined over time.[28]

While LEC agreed with EPA that the injection of activated carbon is the most effective means of reducing mercury emissions from lignite-powered units, LEC also criticized EPA for ignoring the well-known diminishing returns of injecting more carbon. With each marginal increase in carbon

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[25] Risk Assessment, Tbl. 2a (indicating cancer risks of 8.07e-08, 3.09e-08, 1.31e-08, 1.21e-08, and 5.12e-09 for Facility NEI IDs 380578086511, 380578086311, 380558011011, 380578086511, 380578086611 (Milton R. Young, Leland Olds, Coal Creek, Antelope Valley, and Coyote).
[26] *Id*., at Tbl. 2a (indicating the target organ of the risk associated with the plants identified in note 5 is "respiratory").
[27] J. Cichanowicz et al., *Technical Comments on National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units Review of Residual Risk and Technology*, at 29, Figure 6-7 (June 2, 2023) ("Cichanowicz Report").
[28] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

injection, the incremental increase in emission reduction capability falls. Thus, injecting more and more carbon will not necessarily result in greater emission reductions beyond a certain injection level. LEC asked EPA to evaluate the effect of diminishing returns on its conclusion that North Dakota lignite-powered facilities can achieve the standard designed for all other units of 1.2 lb/TBtu.

EPA does not appear to have taken the above concerns into account in claiming lignite- powered facilities can achieve the performance levels achieved at subbituminous plants. As a result, EPA has significantly underestimated the level of control needed to achieve the proposed standard of 1.2 lb/TBtu. Contrary to the analysis EPA relies upon to justify lowering the standard for lignite plants, control efficiencies of greater than 90 percent would be needed for North Dakota lignite-powered facilities.[29] LEC's comments asked EPA to reconsider its proposal in light of these concerns, and in light of EPA's legal obligation to ensure all standards are "achievable," which means they "must be capable of being met under most adverse conditions which can reasonably be expected to recur."[30]

The Administrative Record indicates a key reason why EPA's proposed standards are unachievable is the chemical composition of North Dakota lignite. For example, lignite has different heat and moisture content than subbituminous coals. As a result, a greater volume of fuel and air is needed at lignite plants to produce the same heat input compared to subbituminous plants. Due to higher fuel and air flows, a much greater volume of sorbent is needed to achieve similar emission reductions, and the additional sorbent dramatically increases cost, and therefore reduces the cost-effectiveness, of the controls.[31]

Another distinguishing difference EPA appeared to overlook in its proposal is the higher sulfur concentration in North Dakota lignite relative to subbituminous Powder River Basin coal, which in turn produces a higher level of sulfur trioxide ("SO3"). In the past, EPA has worked with a consultant that recognized this reality as follow:

> With flue gas SO3 concentrations greater than 5-7 ppmv, the sorbent feed rate may be increased significantly to meet a high Hg removal and 90% or greater mercury removal may not be feasible in some cases. Based on commercial testing, capacity of activated carbon can be cut by as much as one half with an SO3 increase from just 5 ppmv to 10 ppmv.[32]

Cichanowicz et al. highlighted this passage from the S&L technology assessment and also noted that the presence of SO3 often affects capture rates in another way—by requiring units with measurable SO3 to be designed with higher gas temperature at the air heater exit to avoid corrosion that would otherwise occur if the SO3 is allowed to cool and condense on equipment

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[29] Cichanowicz Report, at 25, Table 6-1.
[30] *White Stallion Energy Center, LLC v. EPA*, 748 F.3d 1222, 1251 (2014) (citing *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431 n. 46 (D.C. Cir.1980)).
[31] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.
[32] Sargent & Lundy, *IPM Model – Updates to Cost and Performance for APC Technologies: Mercury Control Cost Development Methodology*, Project 12847-002, at 3 (Mar. 2013).

components. However, that higher exit gas temperature also impacts the effectiveness of sorbent injection systems—special-purpose tests on a fabric filter pilot plant showed an increase in gas temperature from 310ºF to 340ºF lowered sorbent Hg removal from 81% to 68%.[33] The higher levels of SO_3 formed by the higher sulfur content found in lignite fuels will inhibit the ability of injected sorbents to reduce mercury emissions at lignite plants to a far greater extent than at subbituminous plants.

LEC agreed with these concerns in its comments and raised another important consideration — the fact that, unlike subbituminous plants, selective catalytic reduction (SCR) is technically infeasible on North Dakota lignite, due to its chemical composition. Although SCR systems are primarily installed for the control of nitrogen oxides (NO_X), SCR can enhance the oxidation of elemental mercury ("Hg^0") which facilitates removal in downstream control equipment, such as wet flue gas desulfurization (FGD) systems.[34] The higher level of mercury control achievable with an SCR is almost certainly why the one lignite plant (Oak Grove) evaluated by EPA as part of its review of the MATS RTR appears capable of achieving the mercury limit set for other coal ranks—it has an SCR that cannot be installed on North Dakota lignite facilities.[35]

LEC's comments also highlighted the experience of two LEC members that recently evaluated the difference in mercury control achieved by plants using subbituminous coal equipped with an SCR and plants using lignite coal without an SCR. Based on those evaluations, North Dakota lignite-powered facilities were found to have much greater difficulty reducing mercury emissions, despite using more than three times the amount of halogenated activated carbon than the subbituminous plant.

In the past, EPA has questioned whether SCR is technically feasible for North Dakota lignite-powered facilities, and recent research has confirmed that the significant challenges associated with using SCR on North Dakota lignite remain unresolved.[36] Although SCR has been demonstrated on the types of lignite found in other parts of the country, North Dakota lignite differs substantially in chemical makeup because it contains a much higher concentration of alkali metals (*e.g.*, sodium and potassium) that render the catalyst ineffective.[37]

In particular, the relatively high concentration of sodium in North Dakota lignite forms vapor, condenses, and then coats other particles, or it forms its own particles at a size range of 0.02-0.05 μm. As a vapor or as a very small particle, the sodium will pass through any upstream emissions control equipment (*e.g.*, electrostatic precipitators and scrubbers), and thus will reach the SCR regardless of whether the SCR is located before other emission control devices (high-dust configuration) or after those other controls (low-dust or tail-end configurations).[38]

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[33] Sjostrom 2016.

[34] 88 Fed. Reg. at 24875.

[35] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[36] *See* Draft SIP, App. D, at D.2.c-5 (citing Benson, Schulte, Patwardhan, Jones (2021) "The Formation and Fate of Aerosols in Combustion Systems for SCR NO_X Control Strategies" A&WMA's 114th Annual Conference, #983723).

[37] *Id.*

[38] *Id.*

Once the sodium particles reach the SCR, they plug the pores of the catalyst, which are the key feature that allows for improved oxidation of other pollutants. The sodium also poisons the catalyst both inside the pores and on the surface, rendering the active component of the catalyst inactive. Recent efforts to address these concerns through either cleaning or regeneration of the catalyst have not been successful, even at pilot scale. A study recently cited by DEQ in its regional haze plan provides additional details on these efforts and the unsolved technical challenges that remain regarding the impact of alkali metals in North Dakota lignite on the technical feasibility of SCR.[39]

According to LEC, its members report that efforts to identify a willing vendor for an SCR on a North Dakota lignite unit have been unsuccessful—all vendors have declined to offer SCR for use on North Dakota lignite once they have closely reviewed the unique characteristics that make SCR infeasible on that particular fuel.[40]

In short, the Administrative Record and other available evidence indicates that North Dakota lignite-powered facilities will likely not be able to meet the revised emission standards EPA is proposing for the MATS Rule.

The Administrative Record Indicates the Lower PM Standard May Also Not Be Technically Feasible

In addition to imposing a more stringent mercury standard on lignite by essentially eliminating the subcategory, EPA's proposal also lowers the standard on fPM for all existing units to the level previously deemed achievable only by new units. However, like its proposed Hg standard for lignite, EPA's proposal to revise the PM standard for all coal types remains unjustified by any demonstration of potential human health or environmental benefits.

The LEC's comments detail particular concerns associated with EPA's failure to provide a reasonable justification for so dramatically reducing the PM limit.[41] As LEC noted, the risks that the MATS Rule is designed to address have already been eliminated, down to several orders of magnitude below the level at which Congress directed EPA to stop regulating. The highest residual risk for the entire source category, which is based on an oil-fired unit, is just one tenth of EPA's acceptable level of risk, and the highest risk from any coal plant is more than an order of magnitude below the risk presented by oil-fired units.

Furthermore, the Administrative Record suggests that EPA's analysis of the achievability of the new 0.01 lb/mmBtu standard is based on an arbitrary data set, and that analysis also suffers from a lack of transparency. Specifically, commenters observed that EPA relies on a Sargent & Lundy memorandum that lacks sufficient detail or supporting documentation to verify the assumptions made, essentially hiding much of the agency's thought process behind the claim that the

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[39] *Id.*

[40] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[41] *Id.*

information on which it is based is not available in public forums.[42] In doing so, EPA seemingly commits what it has previously cited as error in plans developed by states and industry—failing to provide sufficient information to understand the reasoning underlying key conclusions.[43]

Moreover, the Administrative Record indicates the combined effect of both the proposal to require universal use of CEMS and the lower standard of 0.01 lb/mmBtu will present a compounded challenge if finalized as proposed. Commenters indicated that the difficulty in demonstrating achievement of the new standard will be exacerbated by the requirement to use the less accurate CEMS, and the difficulty in using CEMS will be exacerbated by the dramatically lower standard.[44] In particular, serious concerns remain with respect to whether a fPM CEMS can effectively estimate emission rates at such low levels, or whether emissions that low will be too small for a CEMS to differentiate compliance from a false reading.[45] EPA attempts to allay these fears by claiming existing units can simply follow in the footsteps of new units, since new units have been subject to a CEMS requirement with a fPM emission limit of 0.090 lb/megawatt-hour since the inception of MATS.[46] **But that assurance provides no comfort—there are no new units.[47]**

In light of these shortcomings, the NDTA contracted with Center of the American Experiment to model the impacts of the MATS rules on resource adequacy, reliability, and cost of electricity to consumers. The findings of this analysis are detailed in Section D.

Section C: Impact of MATS Regulations- Power Plant Economics and Grid Reliability

Power Plant Economic Impacts

The economic impacts for a lignite power plant from the Mercury and Air Toxics Standards (MATS) finalized rule can be substantial. The updated MATS rule, if implemented by the

[42] *PM Incremental Improvement Memo*, Doc. ID EPA-HQ-OAR-2018-0794-5836 (March 2023) ("Improvements to existing particulate control devices will be dependent on a range of factors including the design and current operation of the units, which is not documented in public forums. … Unfortunately, the details of how those units' ESP designs, upgrades, and operation are not publicly available …. In order to evaluate the applicability of one or more of these potential improvements, information would need to be known about the existing ESPs and their respective operation which is not documented in public forums.").

[43] *See, e.g., Approval and Promulgation of Implementation Plans; Louisiana; Regional Haze State Implementation Plan*, 82 Fed. Reg. 32,294, 32,298 (July 13, 2017) ("Entergy's DSI and scrubber cost calculations were based on a propriety [sic] database, so we were unable to verify any of the company's costs. … Because of these issues, we developed our own control cost analyses ….").

[44] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

[45] *Id.*

[46] 88 Fed. Reg. at 24874. The electrical output-based limit for new EGUs translates to approximately 0.009 lb/mmBtu, which is slightly below EPA's proposed limit of 0.010 lb/mmBtu.

[47] Jason Bohrer, "Comments on *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24854 (Apr. 24, 2023), June 23, 2024.

Environmental Protection Agency (EPA), aims to reduce mercury and other hazardous air pollutant emissions from coal-fired power plants. Coal-firing power plants, and lignite-firing power plants in particular, may face specific challenges and economic consequences in complying with these regulations, which could result in their forced retirement. Some potential economic impacts include:

1. **Escalating Operational Expenditures:** Under this rule, lignite power plants will face an excessive economic burden from a significant uptick in operational costs due to the integration of pollution control equipment. The installation of advanced technologies like activated carbon injection (ACI) and flue gas desulfurization (FGD) systems necessitates continuous monitoring and maintenance to ensure optimal performance. Design specifications vary from plant to plant which increases the complexities of the operating systems that require regular cleaning, replacement of consumables, and calibration, all of which incur additional expenses. Moreover, the implementation of pollution control, measures may necessitate alterations in combustion processes or the introduction of supplementary fuel, further driving up operational costs. As a result, lignite power plants are burdened with substantial ongoing expenditures, while also lacking a positive cost benefit analysis, which will undermine their economic viability and competitiveness in the energy market**.**

2. **Dilemma of Plant Retrofitting or Retirement:** Lignite power plants are confronted with the challenging prospect of either retrofitting existing facilities or contemplating retirement in response to the stringent requirements of the Mercury and Air Toxics Standards (MATS). Plant retrofitting involves substantial investment in upgrading equipment and implementing advanced pollution control technologies to achieve compliance with regulatory mandates. However, these retrofitting endeavors entail significant additional costs, potentially straining the financial resources of plant owners and operators. Moreover, the uncertainty surrounding the long-term economic viability of retrofitted plants further complicates decision-making processes**.**

3. **Impact on Electricity Prices:** The implementation of pollution control technologies to comply with MATS regulations can impose significant financial burdens on lignite power plants. These costs, encompassing the installation, maintenance, and operation of such technologies, would ultimately be transferred to consumers in the form of higher electricity prices. As power plants seek to recoup the expenses incurred in meeting regulatory requirements, consumers will experience an uptick in their electricity bills. This escalation in electricity prices will have far-reaching implications for households, businesses, and industries reliant on affordable energy. It will affect household budgets, impact the competitiveness of businesses, and influence consumer spending patterns. Additionally, higher electricity prices will introduce challenges for industries sensitive to energy costs, potentially leading to shifts in production, investment, and employment patterns within the broader economy. Therefore, the economic impact of elevated electricity prices resulting

from MATS compliance should be carefully considered within the context of the energy market, taking into account the implications for consumers, businesses, and overall economic growth.

4. **Employment Effects:** The escalation in costs and the possibility of plant retrofitting or retirement can reverberate through the lignite industry and associated sectors, potentially leading to job losses. As lignite power plants grapple with increased operational expenses and the financial strain of compliance with regulatory requirements, they may be compelled to streamline operations or even cease production altogether. Such decisions can have a ripple effect on employment within the community, impacting not only plant workers but also individuals employed in ancillary industries such as mining, transportation, and manufacturing. Job losses in these sectors can contribute to economic challenges, including reduced consumer spending, increased unemployment rates, and a decline in overall economic activity. Furthermore, the social and psychological impacts of job loss on affected individuals and communities cannot be understated, as they may face financial insecurity, stress, and uncertainty about their future prospects. Therefore, the potential job impacts stemming from increased costs and plant adjustments underscore the broader economic implications of regulatory compliance measures in the lignite industry.

5. **Regional Economic Consequences:** Lignite power plants are often linchpins of regional economies, exerting substantial influence on employment, tax revenue, and economic activity. Any shifts in the economic viability of these plants, whether due to increased costs, regulatory compliance burdens, or operational adjustments, will trigger broader consequences for local economies. The potential closure or downsizing of lignite power plants can result in the loss of direct and indirect employment opportunities, affecting not only plant workers but also individuals and businesses reliant on plant-related activities. Moreover, the decline in plant operations will lead to reduced tax revenue for local governments, impacting their ability to fund essential services and infrastructure projects. Additionally, the loss of economic activity associated with lignite power plants will ripple through the supply chain, affecting suppliers, vendors, and service providers in the region. This domino effect will exacerbate economic challenges, including decreased consumer spending, increased business closures, and a general downturn in economic vitality. Therefore, changes in the economic landscape of the lignite industry will have far-reaching consequences for regional economies, underscoring the interconnectedness between energy production, employment, and overall economic well-being at the local level.

6. **Impact on Investment Decisions:** The economic ramifications of the MATS rule can significantly shape investment decisions within the lignite industry. Plant owners and prospective investors must carefully evaluate the long-term economic feasibility and potential returns on investment in light of stringent regulatory compliance mandates. The substantial costs associated with MATS compliance, including technology upgrades and operational adjustments, may deter investment in lignite power plants or prompt

divestment from existing assets. Investors may reassess the risk-return profile of lignite-related ventures, considering factors such as regulatory uncertainty, market volatility, and shifting energy trends. Moreover, the potential for increased operational costs and regulatory burdens may incentivize investment in alternative energy sources or cleaner technologies, which align more closely with evolving environmental and sustainability objectives. Therefore, the economic implications of the MATS rule play a pivotal role in shaping investment decisions within the lignite industry, influencing capital allocation, project planning, and strategic resource allocation strategies.

7. **Legal and Regulatory Costs:** Meeting MATS requirements often entails significant legal and regulatory costs associated with monitoring, reporting, and ensuring continued compliance. Lignite power plants must allocate resources to navigate complex regulatory frameworks, engage legal counsel, and implement robust monitoring and reporting systems to adhere to emissions standards. These additional expenses contribute to the overall economic strain on lignite power plants, exacerbating the financial challenges associated with regulatory compliance. As a result, the burden of legal and regulatory costs further underscores the financial pressures faced by lignite power plant operators, shaping their strategic decision-making and resource allocation efforts.

Grid Reliability Impacts

Compliance with the Mercury and Air Toxics Standards (MATS) rule will likely have grid reliability impacts on regional power grids that rely on lignite- or other coal-firing power plants. The impacts on grid reliability for power grids that rely on lignite- or other coal-firing power plants can include:

1. **Operational Adaptations and Flexibility Constraints**: The implementation of pollution control technologies like activated carbon injection (ACI) and flue gas desulfurization (FGD) systems necessitates operational modifications within lignite power plants. These adjustments may include alterations to combustion processes, fuel handling procedures, and overall plant operations to accommodate the integration of new equipment and systems. However, such operational changes can compromise the inherent flexibility of lignite power plants to respond effectively to fluctuating load conditions and grid demands. The need for continuous operation of pollution control systems, coupled with potential limitations in responsiveness, may impede the plant's ability to ramp up or down quickly in response to changes in electricity demand or supply. Consequently, the reliability of lignite power plants to maintain grid stability and meet grid operator requirements may be compromised, raising concerns about their ability to ensure consistent and secure electricity supply. Thus, while MATS compliance aims to mitigate environmental impacts, the operational adaptations required may introduce challenges to the reliability and flexibility of lignite power plants in supporting a resilient and dynamic energy grid.

2. **Disruptions Due to Equipment Installation**: The installation and retrofitting of pollution control equipment often necessitate temporary shutdowns or reduced operating capacities within lignite power plants. These planned downtime periods are essential for integrating new equipment, conducting modifications, and ensuring compliance with regulatory requirements. However, the interruptions in plant operations during these installation phases will have adverse effects on the overall reliability and availability of the plant. The temporary cessation of power generation activities will disrupt electricity supply, potentially affecting grid stability and reliability. Moreover, extended downtime periods may lead to revenue losses for plant operators and suppliers, as well as inconvenience for consumers and end-users reliant on consistent electricity provision. Therefore, while essential for achieving compliance with MATS regulations, the equipment installation process poses challenges to the reliability and continuity of lignite power plant operations, emphasizing the importance of efficient planning and management to minimize disruptions.

3. **Efficiency Implications**: The introduction of pollution control technologies, especially those targeting mercury emissions reduction, will potentially undermine the overall efficiency of lignite power plants. While these technologies play a crucial role in meeting regulatory standards, they often require additional energy inputs and introduce operational complexities that can compromise plant efficiency. For instance, activated carbon injection (ACI) systems necessitate the injection of powdered carbon into the flue gas stream, which can increase resistance and pressure drops within the system, thus reducing overall efficiency. Similarly, flue gas desulfurization (FGD) systems require energy-intensive processes such as limestone slurry preparation and circulation, further impacting plant efficiency. The reduction in efficiency can translate to decreased electricity output per unit of fuel input, potentially affecting the plant's ability to generate electricity reliably and meet demand fluctuations. Consequently, while pollution control measures are essential for environmental protection, the associated efficiency implications underscore the need for careful optimization and balancing of environmental and operational considerations to ensure reliable power generation from lignite plants.

4. **Elevated Maintenance Demands**: The incorporation of MATS-compliant equipment, including ACI and FGD systems, often translates to heightened maintenance requirements within lignite power plants. The intricate nature of these pollution control technologies necessitates more frequent inspections, cleaning, and servicing to ensure optimal performance and regulatory compliance. However, the increased maintenance needs can result in extended periods of downtime, during which the plant may be unable to generate electricity, impacting its reliability and availability. Moreover, the allocation of resources and manpower to address maintenance tasks diverts attention and resources away from other operational activities, potentially affecting overall plant efficiency and productivity. Therefore, while essential for environmental compliance, the elevated maintenance

demands associated with MATS-compliant equipment pose challenges to the reliability and operational continuity of lignite power plants, highlighting the importance of proactive maintenance planning and execution to minimize disruptions.

5. **Inherent Fuel Supply Hurdles:** Lignite power plants grapple with inherent challenges associated with the utilization of lignite coal, particularly in meeting stringent emission standards. Lignite, characterized by its lower rank and elevated moisture content, poses unique obstacles in combustion processes. The variability in chemical composition across different seams of coal extracted from mines further complicates the task of ensuring consistent and efficient combustion. Each seam presents distinct combustion characteristics, necessitating meticulous adjustments in operational parameters to maintain compliance with emission regulations. Consequently, lignite power plants encounter difficulties in securing a reliable and uniform fuel supply, which undermines their ability to consistently meet emission targets and operational efficiency goals. The intricacies of managing diverse coal qualities exacerbate the complexities of pollution control measures, posing significant operational challenges for lignite power plants.

6. **Integration Challenges**: The introduction of new pollution control technologies into operational lignite power plants may encounter compatibility hurdles. Ensuring seamless integration with existing infrastructure is paramount for preserving reliability. Compatibility issues can emerge from differences in technology specifications, operational parameters, or control systems between the new equipment and the plant's established infrastructure. Unaddressed disparities may lead to operational inefficiencies, malfunctions, or system failures. Thus, meticulous planning and coordination are vital to mitigate compatibility risks and uphold the reliability of lignite power plants. Failure to address these challenges will compromise plant performance, emphasizing the need for thorough assessment and integration procedures when adopting new technologies.

7. **System Coordination and Grid Stability:** Adjustments in operating conditions and responses to fluctuating load demands can disrupt system coordination and compromise grid stability. Lignite power plants must coordinate closely with grid operators to maintain reliable electricity supply while adhering to MATS requirements. Changes in plant operations, such as implementing pollution control technologies or adjusting output levels, can affect the overall balance of supply and demand within the grid. Without effective coordination, these changes may lead to imbalances, voltage fluctuations, or frequency deviations, posing risks to grid stability. Therefore, robust communication and collaboration between lignite power plants and grid operators are essential to ensure seamless integration of plant operations with broader grid dynamics. By coordinating effectively, lignite power plants can contribute to grid stability while meeting regulatory obligations, ensuring the reliable delivery of electricity to consumers.

8. **Continuous Compliance Management**: Adhering to emission limits mandated by MATS necessitates ongoing monitoring and fine-tuning of pollution control equipment. The chemical properties of lignite can vary even within coal seams from the same mine, posing challenges in preparation and adjustment for plant operations. This variability complicates efforts to maintain consistent compliance, requiring dynamic adjustments in day-to-day plant operations. Consequently, ensuring reliable compliance becomes a dynamic process, demanding meticulous attention to detail and proactive management of pollution control systems. Consistent monitoring and adjustment are essential to mitigate emissions effectively while sustaining the operational reliability of lignite power plants amidst the inherent variability of lignite coal properties.

9. **Supply Chain Vulnerabilities:** The consolidation in the power plant equipment sector over the past decade has reduced the number of suppliers available. Relying on specific suppliers for pollution control equipment and technologies introduces supply chain risks. Disruptions in the supply chain, such as shortages, delays, or quality issues, will impede the timely installation and operation of essential equipment, jeopardizing reliability. Lignite power plants must carefully assess and manage these supply chain vulnerabilities to ensure uninterrupted access to critical components and technologies necessary for regulatory compliance and operational integrity. Proactive measures, such as diversifying suppliers or implementing contingency plans, are crucial for mitigating supply chain risks and maintaining the reliability of lignite power plants.

10. **Long-Term Viability and Aging Infrastructure:** Compliance with MATS regulations will raise concerns about the long-term viability of older lignite power plants. Aging infrastructure may struggle to adapt to the requirements of new pollution control technologies, posing challenges that will impact reliability. The integration of these technologies into outdated systems may require extensive retrofitting or upgrades, which can strain resources and prolong downtime. Moreover, the operational lifespan of aging infrastructure may be limited, leading to questions about the economic feasibility of investing in costly compliance measures. Plant owners must carefully assess the cost-benefit ratio of compliance efforts and consider the potential impact on reliability when evaluating the long-term viability of older lignite power plants. Failure to address these challenges will compromise the reliability and competitiveness of these facilities in the evolving energy landscape.

Section D: Modeling Results

Summary

The EPA did not conduct a reliability analysis for its proposed MATS rules or its Post IRA base case, instead it conducted a Resource Adequacy and reserve margin analysis, which EPA has claimed is necessary but not sufficient to grid reliability.[48]

EPA's lack of reliability modeling prompted several entities to voice concerns in the original docket for the Proposed MATS rule would negatively impact grid reliability, including the National Rural Electric Coop Association, the American Coal Council, The Lignite Energy Council, PGen, the American Public Power Association, and the National Mining Association.[49,50,51,52,53,54]

To provide this necessary perspective, Center of the American Experiment modeled the reliability and cost impacts of the proposed Mercury and Air Toxics Standards (MATS) in the subregions consisting of the Midcontinent Independent Systems Operator (MISO) as it relates to the elimination of the subcategory for lignite-fired power plants.[55,]

Our analysis determined that the closure of lignite-fired powered power plants in the MISO footprint would increase the severity of projected future capacity shortfalls, i.e. rolling blackouts, in the MISO system if these resources are replaced with wind, solar, battery storage, and natural gas plants consistent with the EPA's estimates for capacity values for intermittent and thermal resources.

Building these replacement resources would come at a great cost to MISO ratepayers. The existing lignite facilities are largely depreciated assets that generate large quantities of dispatchable, low-cost electricity. Our modeling determined the total cost of replacement generation capacity in the Status Quo, Partial, and Full scenarios will cost $12.93 billion, $14.88 billion, and $16.76 billion, respectively, from 2024 through 2035, resulting in incremental costs of $1.9 billion in the Partial

[48] Resource Adequacy Analysis Technical Support Document, New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal Docket ID No. EPA-HQ-OAR-2023-0072 U.S. Environmental Protection Agency Office of Air and Radiation April 2023.
[49] NRECA Comments, EPA-HQ-OAR-2018-0794-5956, at 5-6.
[50] American Coal Council Comments, EPA-HQ-OAR-2018-0794-6808, at 3.
[51] LEC Comments, EPA-HQ-OAR-2018-0794-5957, at 17.
[52] PGen Comments, EPA-HQ-OAR-2018-0794-5994, at 5.
[53] APPA Comments, EPA-HQ-OAR-2018-0794-5958, at 33.
[54] NMA Comments, EPA-HQ-OAR-2018-0794-5986, at 29.
[55] U.S. Environmental Protection Agency, "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review," 88 FR 24854, April 24, 2023, https://www.federalregister.gov/documents/2023/04/24/2023-07383/national-emission-standards-for-hazardous-air-pollutants-coal--and-oil-fired-electric-utility-steam.

scenario and $3.8 billion in the Full scenario through 2035, compared to operating the current lignite facilities under status quo conditions.

MISO residents would also suffer economic damages from the increased severity of rolling blackouts, which can result in food spoilage, property damage, lost labor productivity, and loss of life. American Experiment calculated the economic damages associated with the increase in unserved electricity demand using a metric called the Value of Lost Load (VoLL) criteria, which can be thought of as the Social Cost of Blackouts.

Our analysis found that the MATS rule would cause an additional 73,699 additional megawatt hours (MWh) of unserved load in the in the Full MATS Retirement scenario in 2035 using 2019 hourly electricity demand and wind and solar capacity factors. Using a conservative value for the VoLL of $14,250 per MWh, we conclude the MATS rule would produce economic damages of $1.05 billion under these conditions.

Therefore, the incremental costs stemming from the closure of the 2,264 MW of lignite fired capacity in MISO under the Full scenario exceeds the projected net present value benefits of $3 billion from 2028 through 2037 using a 3 percent discount rate modeled by EPA in its Regulatory Impact Analysis.

Modeling the Reliability and Cost of the MISO Generating Fleet Under Three Scenarios

Our analysis examined the impact of the proposed MATS rules on the reliability of the MISO system through 2035 by comparing two lignite retirement scenarios to a "Status Quo" scenario that represents "business as usual" that assumes no changes to the generating fleet occur due to the MATS rule, or any other of EPA's pending regulations.[56]

Status Quo scenario: Installed generator capacity assumptions for MISO in the Status Quo scenario are based on announced retirements from U.S. Energy Information Administration (EIA) database and utility Integrated Resource Plans (IRPs) through 2035 compiled by Energy Ventures Analysis on behalf America's Power, a trade association whose sole mission is to advocate at the federal and state levels on behalf of the U.S. coal fleet.[57] This database is also used by the NERC LTRA suggesting it is among the most credible databases available for this analysis.[58] It should be noted that this database leaves considerably more coal and natural gas on its system than the MISO grid EPA assumes will be in service in the coming years in its Proposed Rule Supply Resource

[56] See Appendix 2: Capacity Retirements and Additions in Each Scenario.
[57] America's Power, "Proprietary data base maintained by Energy Ventures Analysis, an energy consultancy with expertise in electric power, natural gas, oil, coal, renewable energy, and environmental policies" Personal Communication, November 3, 2023.
[58] North American Electric Reliability Corporation, "2023 Long-Term Reliability Assessment," December, 2023, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

Utilization file, meaning our reliability assessment will be more conservative than if we used EPA's capacity projections.

Retired thermal resources in the Status Quo scenario are replaced by solar, wind, battery storage, and natural gas in accordance with the current MISO interconnection queue to maintain resource adequacy based on capacity values given to these generators in EPA's Proposed Rule Supply Resource Utilization file.[59] These capacity values are described in greater detail in the section labeled Replacement Capacity Based on EPA Methodology for Resource Adequacy.

Partial MATS Retirement scenario: The Partial MATS retirement scenario assumes 1,150 megawatts (MW) of lignite fired capacity in North Dakota is retired in addition to incorporating all of the announced retirements in the Status Quo. This value was chosen because it represents the retirement of one lignite facility in North Dakota that serves the MISO market. These resources are replaced with wind, solar, battery storage, and natural gas capacity using the methodology described greater detail in the section labeled Replacement Capacity Based on EPA Methodology for Resource Adequacy.[60]

Full MATS scenario: The Full MATS retirement scenario assumes the MATS regulations will cause all 2,264 MW of lignite-fired generators in the MISO system to retire, in addition to incorporating the retirements in the Status Quo scenario will occur.[61] These resources are replaced with wind, solar, battery storage, and natural gas capacity using the methodology described greater detail in the section labeled Replacement Capacity Based on EPA Methodology for Resource Adequacy.[62]

Reliability in each scenario

The EPA did not conduct a reliability analysis for its proposed MATS rules or its Post IRA base case. Instead, it conducted a Resource Adequacy analysis of its proposed rule, compared to the Post IRA base case.

Resource Adequacy and reserve margin analyses can be useful tools for determining resource adequacy and reliability, but the shift away from dispatchable thermal resources (fossil fuel) toward intermittent resources (wind and solar) increases the complexity and uncertainty in these analyses and makes them increasingly dependent on the quality of the assumptions used to construct capacity accreditations.[63]

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[59] U.S. Environmental Protect Agency, "Proposed Regulatory Option," Zip File, https://www.epa.gov/system/files/other-files/2023-04/Proposed%20Regulatory%20Option.zip
[60] See Appendix 3: Replacement Capacity Based on EPA Methodology for Resource Adequacy.
[61] These figures represent the rated summer capacity as indicated by the U.S. Energy Information Administration.
[62] See Appendix 3: Replacement Capacity Based on EPA Methodology for Resource Adequacy.
[63] See Appendix 4: Resource Adequacy in Each Scenario.

This is likely a key reason why EPA has distinguished between resource *adequacy* and resource *reliability* in its Resource Adequacy Technical Support Document for its proposed carbon dioxide regulations on new and existing power plants.[64,65] EPA stated:

> "As used here, the term **resource adequacy** is defined as the provision of adequate generating resources to meet projected load and generating reserve requirements in each power region, while **reliability** includes the ability to deliver the resources to the loads, such that the overall power grid remains stable." **[emphasis added].**" EPA goes on to say that "resource adequacy … is necessary (but not sufficient) for grid reliability.[66]

As the grid becomes more reliant upon non-dispatchable generators with lower reliability values, it is crucial to "stress test" the reliability outcomes of systems that use the EPA's capacity value assumptions in their Resource Adequacy analyses by comparing historic hourly electricity demand and wind and solar capacity factors against installed capacity assumptions in the Status Quo, Partial, and Full scenarios.

We conducted such an analysis by comparing EPA's modeled MISO generation portfolio to the historic hourly electricity demand and hourly capacity factors for wind and solar in 2019, 2020, 2021, and 2022. These data were obtained from the U.S. Energy Information Administration (EIA) Hourly Grid Monitor to assess whether the installed resources would be able to serve load for all hours in each Historic Comparison Year (HCY).[67]

For our analysis, hourly demand and wind and solar capacity factors were adjusted upward to meet EPA's peak load, annual generation, and capacity factor assumptions. These assumptions are generous to the EPA because they increase the annual output of wind and solar generators to levels that are not generally observed in MISO.

Extent of the Capacity Shortfalls

While our modeling determined that the retirement of lignite facilities had a minimal impact on the number of hours of capacity shortfalls observed in the Partial and Full scenarios, retiring the lignite facilities makes the extent of capacity shortfalls worse.

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[64] EPA did not produce a Resource Adequacy Technical Support Document for the MATS rules.
[65] U.S. Environmental Protection Agency, "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review," 88 FR 24854, April 24, 2023, https://www.federalregister.gov/documents/2023/04/24/2023-07383/national-emission-standards-for-hazardous-air-pollutants-coal--and-oil-fired-electric-utility-steam.
[66] Resource Adequacy Analysis Technical Support Document, New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal Docket ID No. EPA-HQ-OAR-2023-0072 U.S. Environmental Protection Agency Office of Air and Radiation April 2023.
[67] U.S. Energy Information Administration, "Hourly Grid Monitor," https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.

For example, Figure D-1 shows largest capacity shortfalls in the Status Quo scenario, which occur in 2035 using the 2021 Historical Comparison Year for hourly electricity demand and wind and solar capacity factors.

Each resource's hourly performance is charted in the graph below. Thermal units are assumed to be 100 percent available, which is consistent with EPA's capacity accreditation for these resources, and wind and solar are dispatched as available based on 2021 fluctuations in generation. Blue sections reflect the use of "Load Modifying Resources," which are reductions in electricity consumption by participants in the MISO market.

Purple areas show time periods where the batteries are discharged. These batteries are recharged on January 8th and 9th using the available natural gas and oil-fired generators. Red areas represent periods where all of the resources on the grid are unable to serve load due to low wind and solar output and drained battery storage systems. At its peak, the largest capacity shortfall is 15,731 MW.

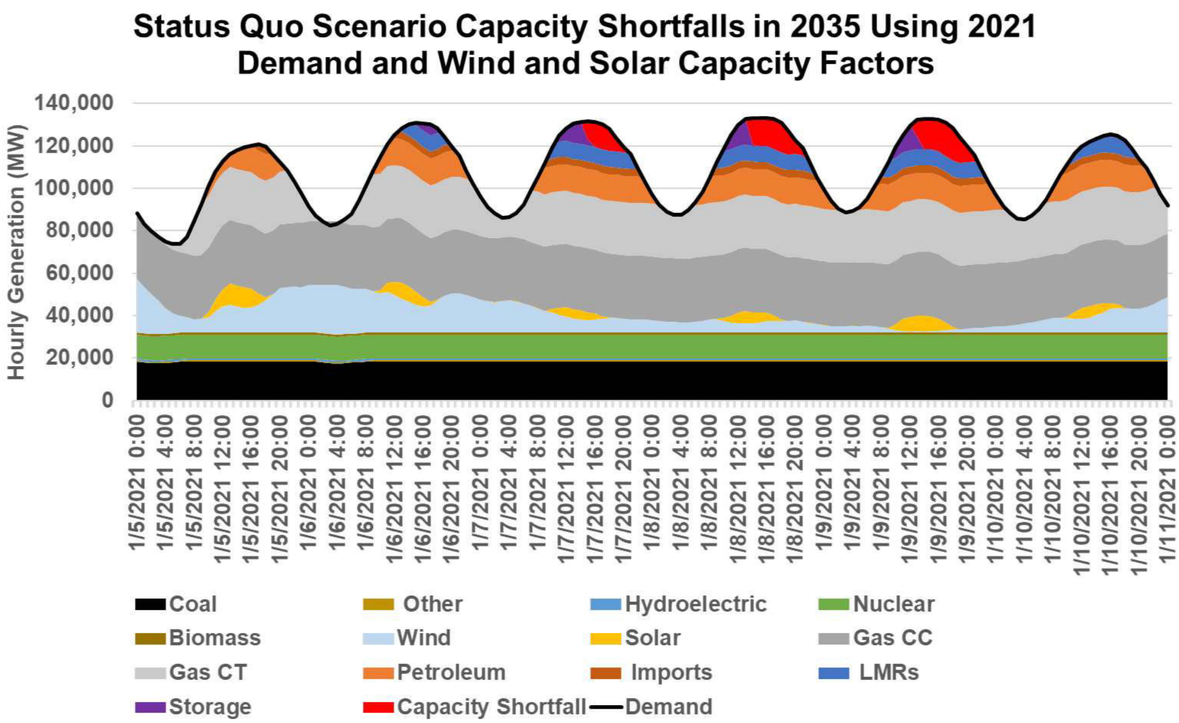

Figure D-1. This figure shows the generation of resources on the MISO grid in the Status Quo during a theoretical week in 2035. The purple portions of the graph show the battery storage discharging to provide electricity during periods of low wind and solar generation. Unfortunately, the battery storage does not last long enough to avoid blackouts during a wind drought.

These capacity shortfalls become more pronounced in the Partial and Full scenarios as less dispatchable capacity exists on the grid to serve load. Figure D-2 shows the three capacity shortfall events in Figure D-1. It depicts the blackouts observed in the Status Quo scenario in green, and the additional MW of unserved load in the Partial and Full scenarios in yellow and red, respectively.

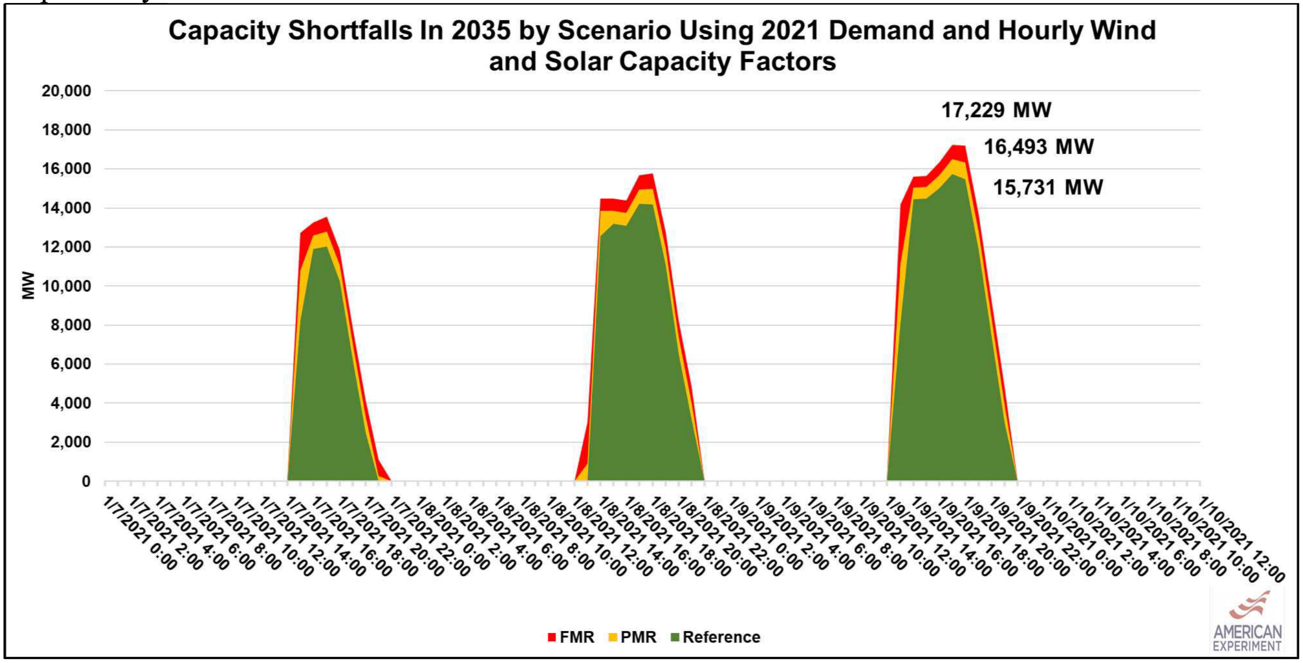

Figure D-2. Capacity shortfalls increase during a hypothetical January 9th, 2035 from 15,731 MW at their peak in the Status Quo to 16,493 MW in the Partial scenario and 17,229 MW in the Full scenario.

Table D-1 shows the largest capacity shortfall, in terms of MW, for each scenario in each of the four Historical Comparison Years studied and the incremental increase in the largest shortfall due to the lignite closures stemming from the MATS rule for the Partial and Full scenarios.

The largest incremental increase in capacity shortfalls would occur in the 2020 HCY in the Full scenario as the blackouts would increase from 552 MW in the Status Quo scenario to 3,295 in the Full scenario, a difference of 2,743 MW.

Maximum MW Shortfalls in 2035 in Each HCY					
Data Year	Status Quo	Partial	Partial Difference	Full	Full Difference
2019	15,130	15,842	712	16,530	1,400
2020	552	2,587	2,034	3,295	2,743
2021	15,731	16,493	762	17,229	1,498
2022	10,615	11,409	794	12,177	1,562

Table D-1. This table shows the largest capacity shortfall, in terms of MW, for each scenario in each of the four Historical Comparison Years studied and the incremental increase in the largest shortfalls due to the lignite closures stemming from the MATS rule for the Partial and Full scenarios.

It is important to note that this difference is larger than the amount of lignite-fired capacity that is retired in the Full scenario (2,264 MW) because the retirement of these facilities reduces the amount of capacity available to charge battery storage resources.

Unserved MWh in Each Scenario

The amount of unserved load in each scenario can also be measured in megawatt hours (MWh). This metric is a product of the number of hours with insufficient energy resources multiplied by the hourly energy shortfall, measured in MW. This metric may be a more tangible way to understand the impact that the unserved load will have on families, businesses, and the broader economy. Each MWh reflects an increment of time where electric consumers in the MISO grid will not have access to power.

Table D-2 shows the number of MWhs of unserved load in each scenario for the four HCYs studied. In some HCYs, the incremental number of unserved MWhs is fairly small, but in other years they are substantial. In the 2020 HCY, the Partial scenario had 2,042 more MWhs of unserved load than the Status Quo scenario, and the Full scenario had 4,265 MWh of additional unserved load, compared to the Status Quo Scenario.

Total MWh Shortfalls in 2035 in Each HCY					
Data Year	Status Quo	Partial	Partial Difference	Full	Full Difference
2019	168,723	204,050	35,327	242,393	73,669
2020	582	2,624	2,042	4,847	4,265
2021	244,743	273,927	29,184	304,021	59,278
2022	53,458	62,223	8,765	71,304	17,846

Table D-2. The incremental MWh of unserved load ranges from 2,042 to 35,327 in the Partial scenario, and from 4,265 to 73,669 in the Full scenario.

In the 2019 HCY, the Partial scenario experienced an additional 35,327 MWh of unserved load and the Full scenario experienced 73,669 MWh of unserved load. These additional MWh of unserved load will impose hardships on families, businesses, and the broader economy.

The Social Cost of Blackouts Using the Value of Lost Load (VoLL)

Blackouts are costly. They frequently result in food spoilage, lost economic activity, and they can also be deadly. Regional grid planners attempt to quantify the cost of blackouts with a metric called the Value of Lost Load (VoLL). The VoLL is a monetary indicator *expressing the costs associated with an interruption of electricity supply*, expressed in dollars per megawatt hour (MWh) of unserved electricity.

MISO currently assigns a Value of Lost Load (VOLL) of $3,500 per megawatt hour of unserved load. However, Potomac Economics, the Independent Market Monitor for MISO, recommended a value of $25,000 per MWh for the region.[68] For this study, we used a midpoint value of $14,250 per MWh of unserved load to calculate the social cost of the blackouts under each modeled scenario.

Table D-3 shows the economic damage of blackouts in each scenario in model year 2035 and shows the incremental increase in the VOLL in the Partial and Full scenarios. Incremental VOLL costs are highest using the 2019 HCY where MISO experiences an additional $503.4 million in economic damages due to blackouts in the Partial scenario, and an additional $1.05 billion in the Full scenario.

Value of Lost Load for Capacity Shortfalls in 2035 in Each HCY					
Data Year	Status Quo	Partial	Partial Difference	Full	Full Difference
2019	$2,404,309,657	$2,907,716,665	$503,407,008	$3,454,098,692	$1,049,789,035
2020	$8,296,505	$37,389,117	$29,092,612	$69,074,216	$60,777,712
2021	$3,487,594,170	$3,903,464,847	$415,870,677	$4,332,301,464	$844,707,294
2022	$761,782,023	$886,680,023	$124,898,001	$1,016,083,680	$254,301,657

Table D-3. MISO would experience millions of dollars in additional economic damage if the lignite fired power plants in its footprint are shut down in response to the MATS regulations.

It is important to note that these VOLL figures are not the total estimated cost impacts of blackouts for the MATS regulations. Rather, they are a snapshot of a range of possible outcomes for the year 2035 based on variations in electricity demand and wind and solar productivity.

The VOLL demonstrates harm of the economy in a multitude of ways. For the industrial/commercial sector, direct costs from losing power (and therefore benefits from avoiding power outages) can be (1) opportunity cost of idle resources, (2) production shortfalls / delays, (3) damage to equipment and capital, and (4) any health or safety impacts to employees. There are also indirect or macroeconomic costs to downstream businesses/consumers who might depend on the products from a company who experiences a power outage.[69]

For the residential sector, the direct costs are different. They can include (1) restrictions on activities (e.g. lost leisure time, lost work time, and associated stress), (2) financial costs through property damage (e.g. damage to real estate via bursting pipes, food spoilage), and (3) health and safety issues (e.g. reliance on breathing machines, air filters).[70]

[68] David B. Patton, "Summary of the 2022 MISO State of the Market Report," Potomac Economics, July 13, 2023, https://cdn.misoenergy.org/20230713%20MSC%20Item%2006%20IMM%20State%20of%20the%20Market%20Recommendations629500.pdf.

[69] Will Gorman, "The Quest to Quantify the Value of Lost Load: A Critical Review of the Economics of Power Outages," The Electricity Journal Volume 35, Issue 8, October 2022, https://www.sciencedirect.com/science/article/pii/S1040619022001130.

[70] Will Gorman, "The Quest to Quantify the Value of Lost Load: A Critical Review of the Economics of Power Outages," The Electricity Journal Volume 35, Issue 8, October 2022, https://www.sciencedirect.com/science/article/pii/S1040619022001130.

Hours of Capacity Shortfalls

Comparing hourly historic electricity demand and wind and solar output to MISO grid in the Status Quo scenario, our modeling found that MISO would have capacity shortfalls in the 2019, 2021, and 2022 HCYs which can be seen in Table D-4 below.

There would be additional capacity shortfalls in all of the HCYs modeled in the Partial and Full scenarios, where the Partial scenario would experience four additional hours of blackouts in 2019 HCY, one additional hour of blackouts in the 2020 HCY, four additional hours of blackouts in 2021 HCY, and one additional hour of blackouts in the 2022 HCY. In the Full scenario, there would be five additional hours of blackouts in the 2019 HCY, one additional hour of blackouts in the 2020 HCY, eight additional hours in the 2021 HCY, and two additional hours in the 2022 HCY, compared to the Status Quo Scenario.

Hours of Capacity Shortfalls in 2035 in Each HCY					
Data Year	Status Quo	Partial	Partial Difference	Full	Full Difference
2019	28	32	4	33	5
2020	2	3	1	3	1
2021	24	28	4	32	8
2022	13	14	1	15	2

Table D-4. Capacity shortfalls occur in three of the four HCYs in the Status Quo scenario and all four HCYs for the Partial and Full scenarios.

Cost of replacement generation

Our VOLL analysis demonstrates that the MATS rules will cause significant economic harm in MISO by reducing the amount of dispatchable capacity on the grid due to lignite plant closures stemming from the removal of the lignite subcategory.

However, load serving entities (LSEs) will also begin to incur costs as they build replacement generation to maintain resource adequacy if lignite resources are forced to retire in response to the proposed MATS rules. These costs will be passed on to electricity consumers and must be calculated to produce accurate estimates of the true cost of the MATS regulations.

We modeled the cost of the replacement generation under the Status Quoe, Partial and Full scenarios. The cost of the Partial and Full scenarios, when compared to the Status Quo scenario, is used to determine the additional economic burden that the MATS regulations will impose onto MISO electricity customers.

Our modeling determined the total cost of replacement generation capacity in the Status Quo, Partial, and Full scenarios will cost $12.93 billion, $14.88 billion, and $16.76 billion, respectively, from 2024 through 2035 (see Figure D-3).

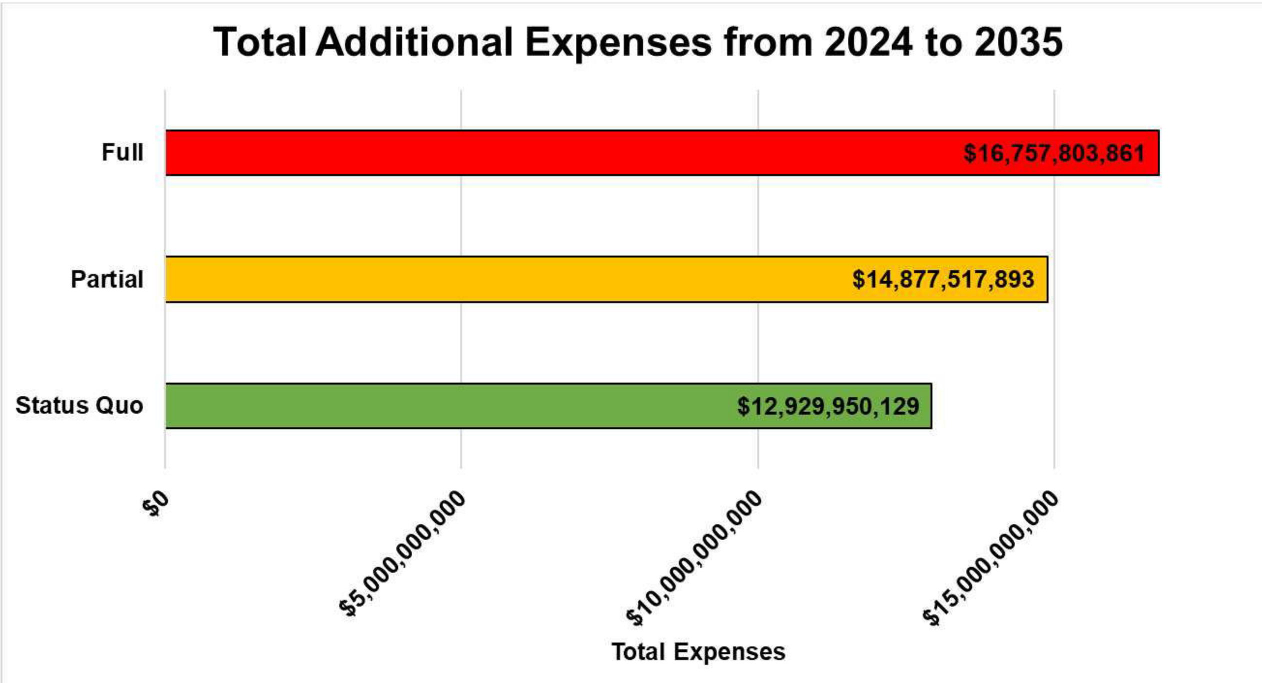

Figure D-3. The Partial scenario will cost $1.95 billion more than the Status Quo scenario from 2024 through 2035 and the Full scenario will cost $3.8 billion more than the Status Quo scenario in this timeframe.

Figure D-4 shows the incremental cost of the Partial and Full scenarios from 2024 through 2030, the period reflecting the up-front costs of complying with the regulations. From 2024 through 2028, LSEs would incur $337 million by building replacement generation in the Partial scenario, compared to the Status Quo scenario, and $654 million in the Full scenario, relative to the Status Quo. It should be noted that these costs are only the cost of building replacement generation and do not factor in the cost of decommissioning or remediating existing power plants or mine sites.

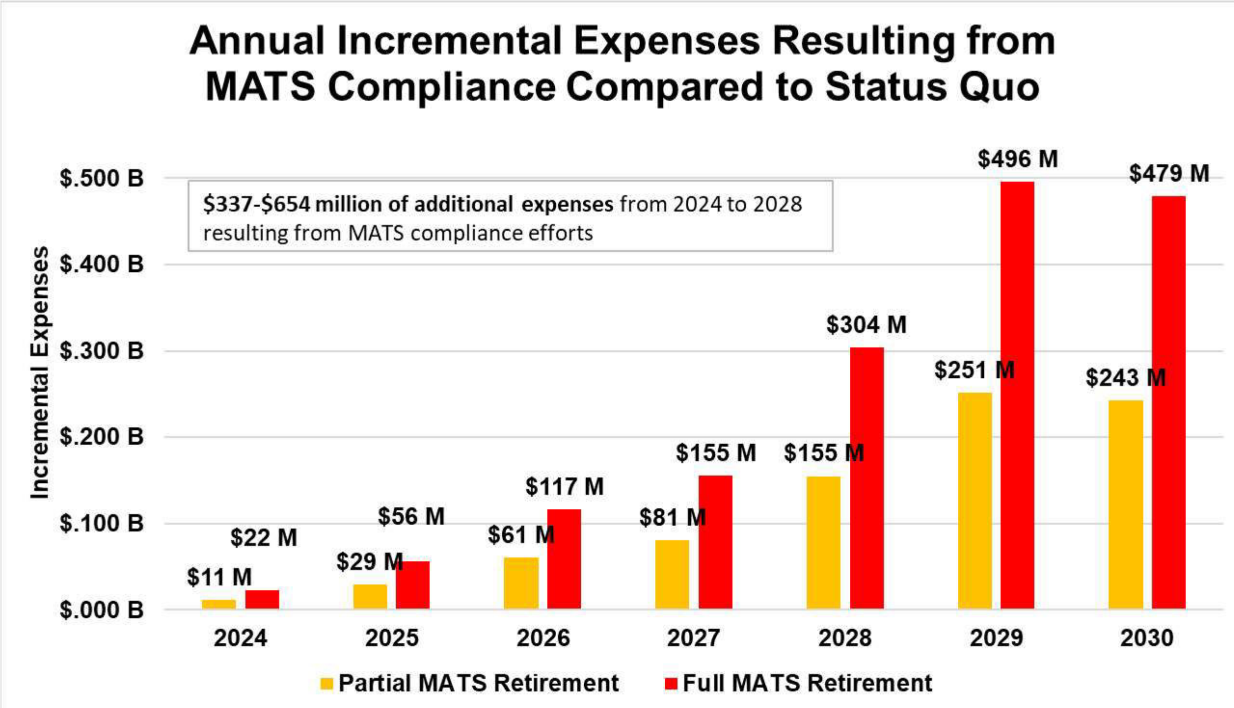

Figure D-4. This figure shows the annual cost of building the replacement capacity needed to maintain resource adequacy after the retirement of the lignite plants based on EPA's capacity accreditation values for wind, solar, storage, and thermal resources.

We describe the total costs of replacement generation capacity for each scenario in greater detail below. The assumptions used to calculate the cost of replacement generation can be found in Appendix 1: Modeling Assumptions.

Status Quo scenario:

The Status Quo scenario results in the retirement of 28,756.8 MW of coal resources, 7,852 MW of natural gas capacity, and 462 MW of petroleum capacity. These retirements are already projected to occur without imposition of the new MATS Rule or other federal regulations. This retired capacity is replaced with 4,306 MW of natural gas, 19,436 MW of wind, 29,652 MW of solar, and 3,304 MW of storage.[71]

The total cost of replacement generation for the Status Quo scenario is $12.9 billion. The majority of these expenses consist of additional fixed costs of building new wind, solar, and battery storage facilities, such as fixed operational and maintenance (O&M), capital costs, and utility returns.

Compared to the current grid, the Status Quo scenario saves $32 billion in fuel costs, $11.5 billion in variable operations and maintenance costs, and $5 billion in taxes. However, these savings are

[71] See Appendix 2: Capacity Retirements and Additions in Each Scenario.

far outweighed by $5.1 billion in additional fixed costs, $16 billion in capital costs, $2.1 billion in transmission costs, and $38.2 billion in utility profits (see Figure D-5).

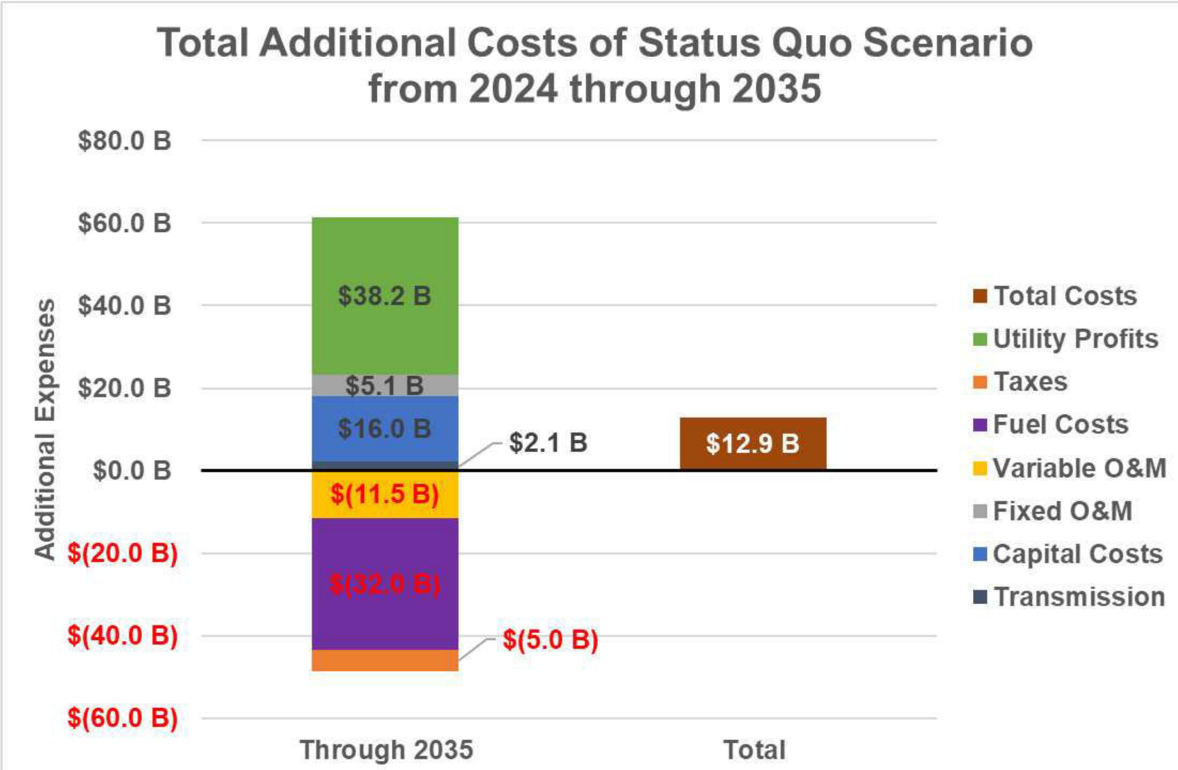

Figure D-5. The Status Quo scenario saves consumers money from lower fuel costs, fewer variable operations and maintenance costs, and lower taxes (due to federal subsidies) but these savings are outweighed by the additional costs. As a result, building the grid in the Status Quo scenario would increase costs by $12.93 billion compared to today's costs.

These additional costs will have an impact on electricity rates. Our cost modeling determined that electricity costs for MISO ratepayers would be 9.89 cents per kWh in the Status Quo scenario, an increase of nearly 3.5 percent relative to current costs of 9.56 cents per kWh.[72]

Partial MATS Retirement scenario:

The Partial scenario results in the closure of 1,151 MW of lignite capacity and necessitates an incremental increase in replacement capacity of 1,015 MW wind, 1,549 MW solar, and 173 MW storage, compared to the Status Quo scenario.[73]

The total cost of replacement generation for the Partial scenario is $14.9 billion, and the total incremental cost is $1.9 billion compared to the Status Quo scenario. The majority of these

[72] Annual Electric Power Industry Report, Form EIA-861 detailed data files, https://www.eia.gov/electricity/data/eia861/.
[73] See Appendix 2: Capacity Retirements and Additions in Each Scenario.

expenses consist of additional fixed costs of building new wind, solar, and battery storage facilities, such as fixed operational and maintenance (O&M), capital costs, and utility returns.

Compared to the current grid, the Partial scenario saves $32.7 billion in fuel costs, $11.6 billion in variable operations and maintenance costs, and $5.1 billion in taxes. However, these savings are far outweighed by $5.3 billion in additional fixed costs, $17.1 billion in capital costs, $2.2 billion in transmission costs, and $39.7 billion in utility profits (see Figure D-6).

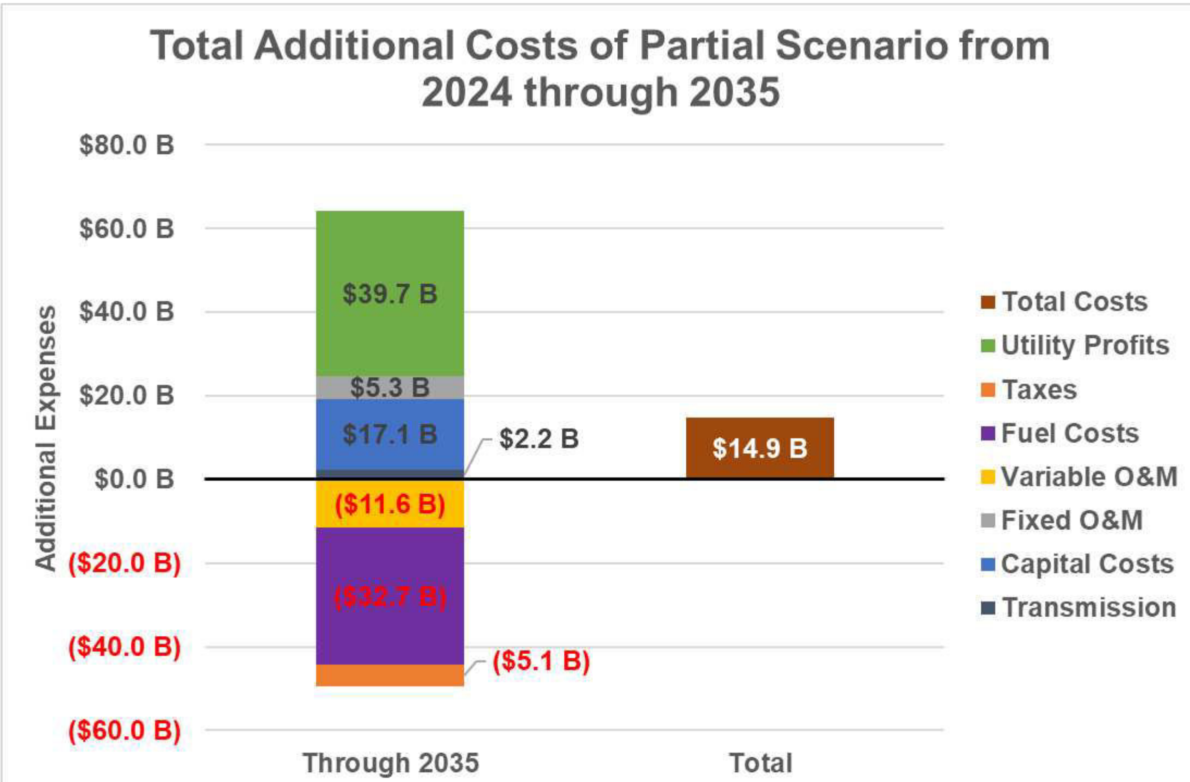

Figure D-6. The Partial scenario results in an $14.88 billion in additional costs compared to the current grid due to additional capital costs, fixed operations and maintenance costs, additional transmission costs, and additional utility profits.

Compared to the Status Quo scenario, the incremental savings are $664 million in fuel costs, $119.7 million in variable operations and maintenance costs, and $102.2 million in taxes, which are outweighed by $178.7 million in additional fixed costs, $1.1 billion in capital costs, $116.5 million in transmission costs, and $1.4 billion in utility profits (see Figure D-7).

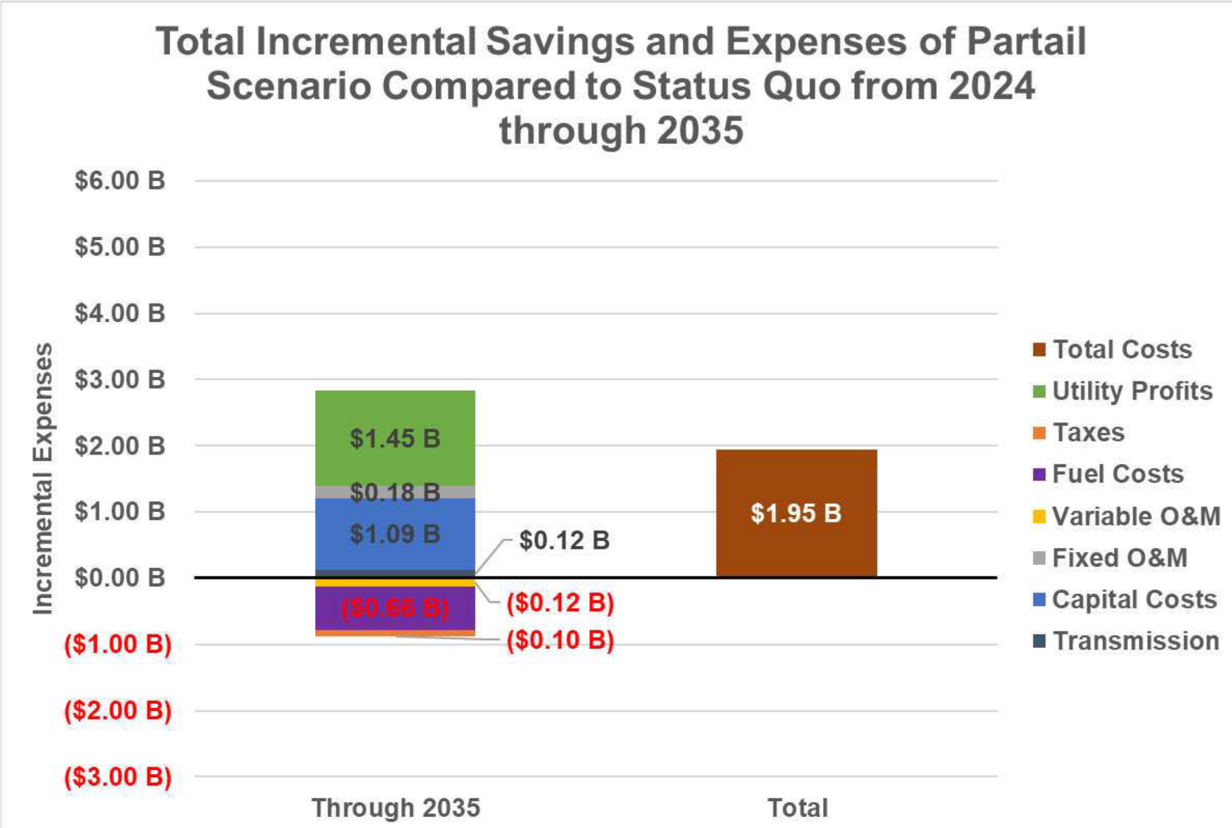

Figure D-7. The Partial scenario will cost MISO ratepayers an additional $1.9 billion from 2024 through 2035.

These incremental costs mean Load Serving Entities will incur an additional $1.9 billion because of these rules. These costs will start incurring before the compliance deadline is finalized in 2028, totaling $337 million of additional expenses compared to the Status Quo scenario (see Figure D-8).

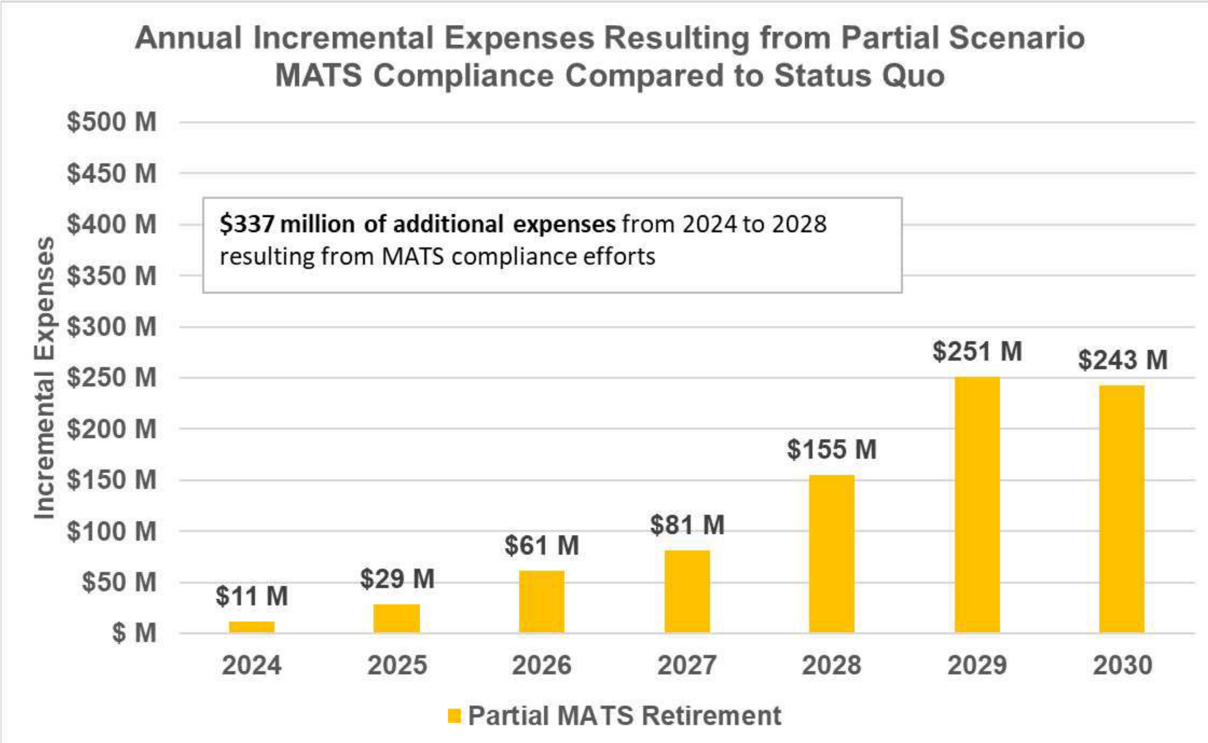

Figure D-8. This figure shows the annual incremental cost incurred by LSEs as a result of the lignite closures in the Partial scenario.

These additional costs will have an impact on electricity rates. Our cost modeling determined that electricity costs for MISO ratepayers would be 9.95 cents per kWh in the Partial scenario, an increase of nearly 3.9 percent relative to current costs of 9.58.

Full MATS scenario:

Under the Full scenario, 2,264 MW of lignite capacity would be forced to retire resulting results in an incremental increase in replacement capacity of 1,997 MW wind, 3,048 MW solar, and 304 MW storage compared to the Status Quo scenario.

The total cost of replacement generation for the Full scenario is $16.8 billion, and the total incremental cost is $3.8 billion compared to Status Quo scenario. The majority of these expenses consist of additional fixed costs of building new wind, solar, and battery storage facilities, such as fixed operational and maintenance (O&M), capital costs, and utility returns.

Compared to the current grid, the Full scenario saves $33.3 billion in fuel costs, $11.7 billion in variable operations and maintenance costs, and $5.2 billion in taxes. However, these savings are far outweighed by $5.4 billion in additional fixed costs, $18.1 billion in capital costs, $2.4 billion in transmission costs, and $41.1 billion in utility profits (see Figure D-9).

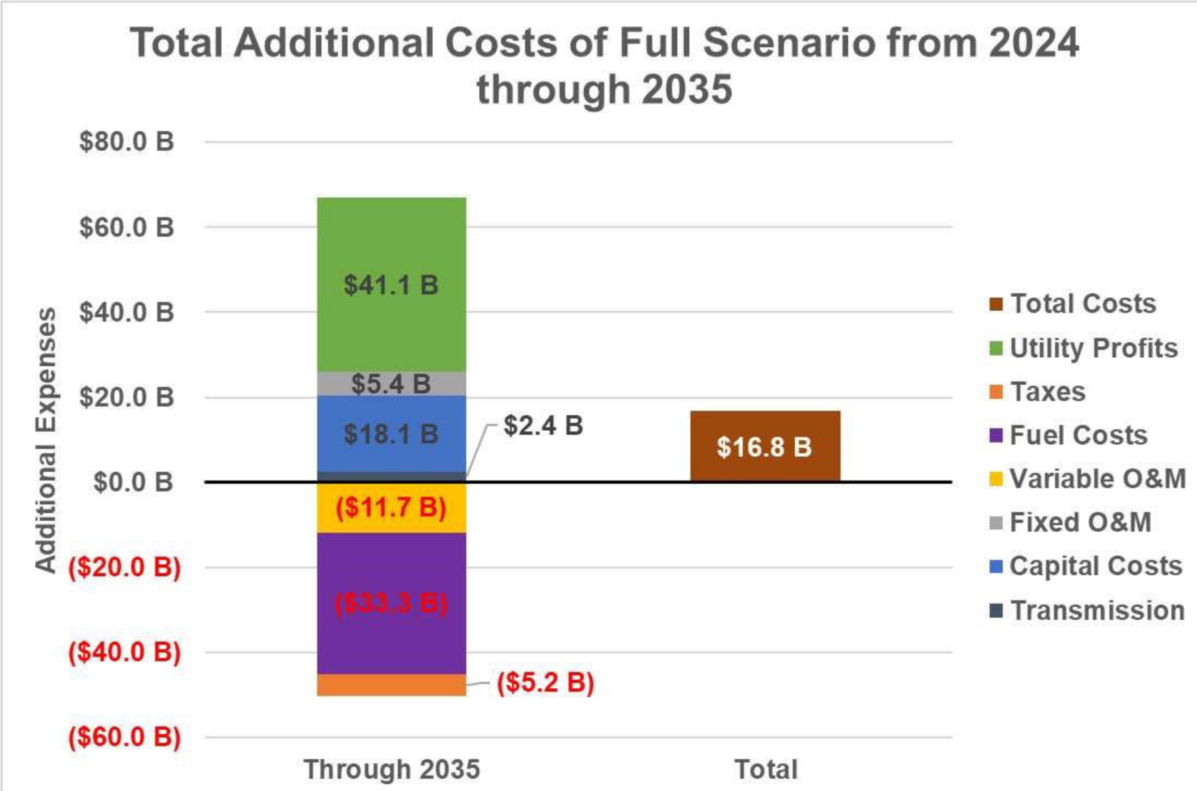

Figure D-9. The Full scenario results in an increase of $16.76 billion in costs compared to the current grid.

Compared to the Status Quo scenario, the incremental savings are $1.3 million in fuel costs, $235.1 million in variable operations and maintenance costs, and $202 million in taxes, which are outweighed by $350.8 million in additional fixed costs, $2.1 billion in capital costs, $229.1 million in transmission costs, and $2.8 billion in utility profits (see Figure D-10).

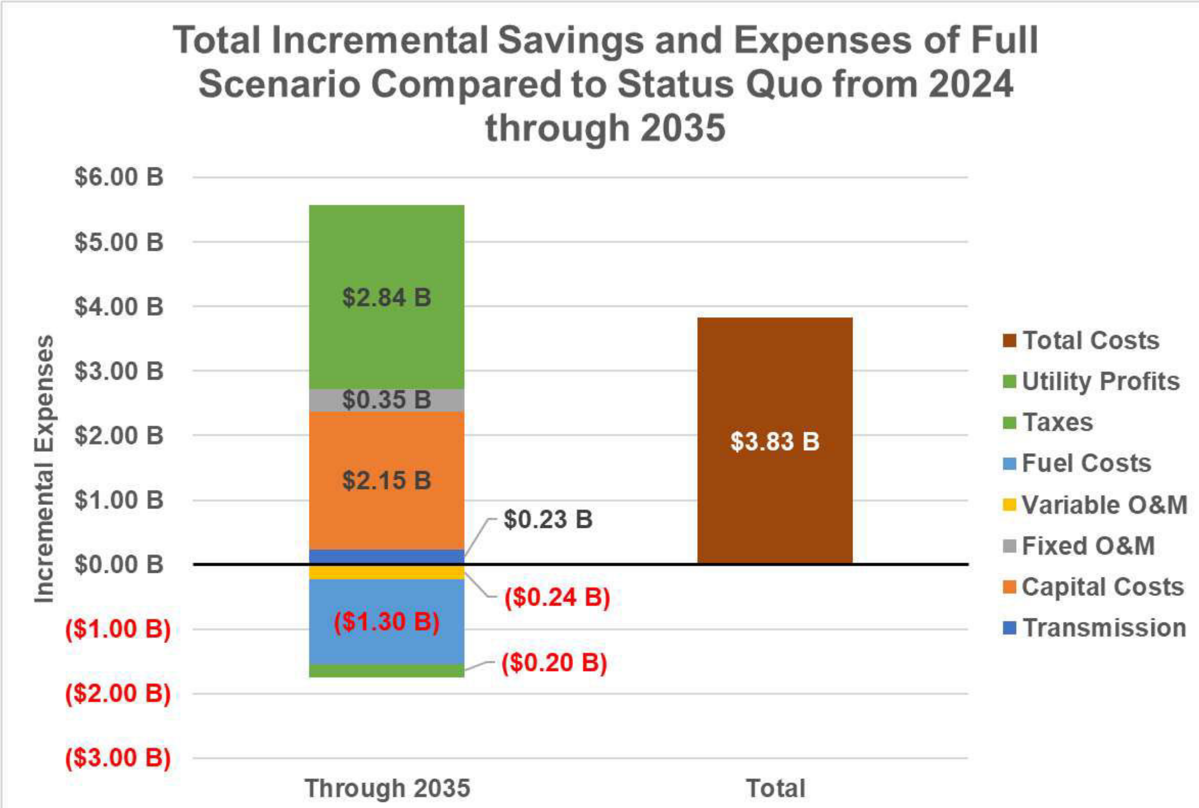

Figure D-10. This figure itemizes the expenses incurred in the Full scenario, which will cost an additional $3.8 billion compared to the Status Quo scenario.

These incremental costs mean Load Serving Entities will incur an additional $3.8 billion in the Full scenario because of these rules. These costs will start incurring before the compliance deadline is finalized in 2028, totaling $654 million of additional expenses compared to the Status Quo scenario (see Figure D-11).

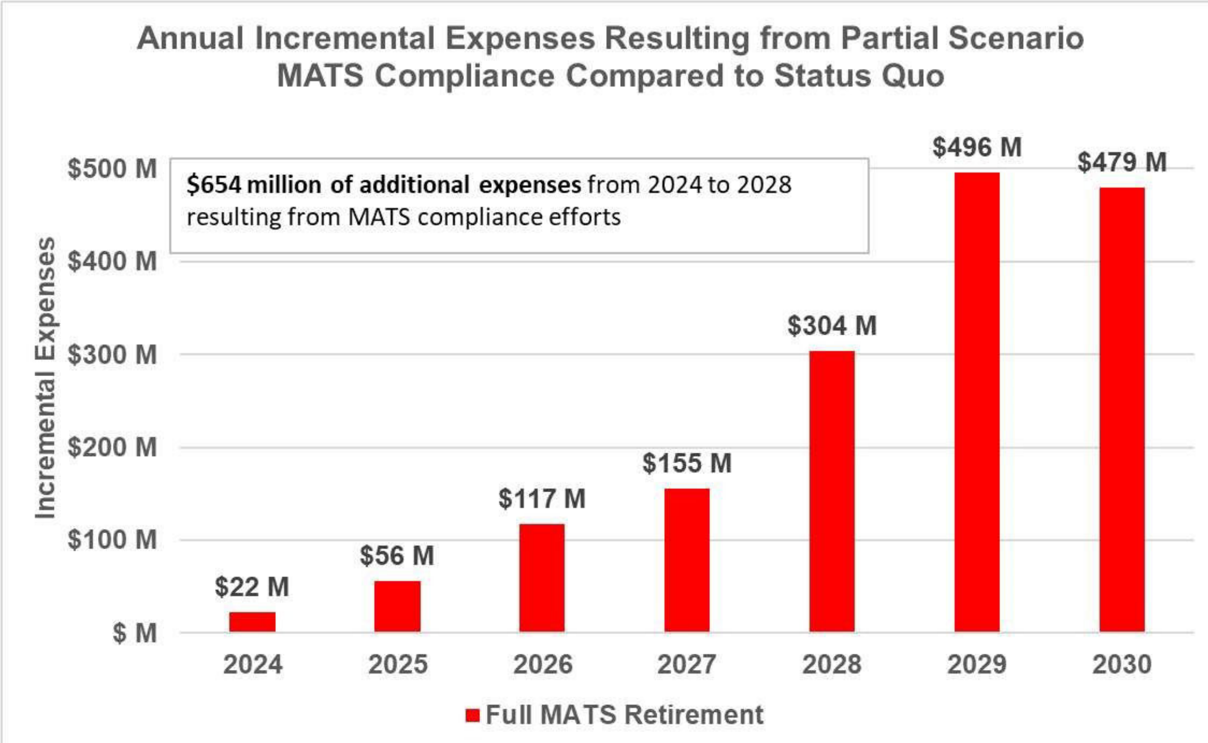

Figure D-11. LSEs would incur an additional $654 million in additional expenses, compared to the Status Quo scenario, as a result of the proposed MATS rules.

These additional costs will have an impact on electricity rates. Our cost modeling determined that electricity costs for MISO ratepayers would be 9.97 cents per kWh in the Full scenario, an increase of nearly 4.1 percent relative to current costs of 9.58.

Conclusion:

By effectively eliminating the subcategory for lignite power plants and ignoring the breadth of evidence demonstrating that these regulations are not reasonably attainable, the MATS rules will increase the severity of capacity shortfalls in the MISO region, resulting in economic damages from the ensuing blackouts ranging from $29 million to $1.05 billion, depending on the HCY used, and imposing $1.9 billion to $3.8 billion in the cost of replacement generation capacity in the Partial and Full scenarios, respectively.

Therefore, the costs stemming from the closure of the 2,264 MW of lignite fired capacity in MISO exceeds the projected net present value benefits of $3 billion from 2028 through 2037 using a 3 percent discount rate modeled by EPA in its Regulatory Impact Analysis.[74]

[74] Regulatory Impact Analysis for the Proposed National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review (Apr. 2023), Docket ID: EPA-HQ-OAR-2018-0794-5837.

Appendix 1: Modeling Assumptions

Electricity Consumption Assumptions

Annual electricity consumption in each model year is increased in accordance with EPA's assumptions in the IPM in each of the MISO subregions.

Peak Demand and Reserve Margin Assumptions

The modeled peak demand and reserve margin in each of the model years are increased in accordance with the IPM in each of the MISO subregions.

Time Horizon Studied

This analysis studies the impact of the proposed MATS rules from 2024 through 2035 to accurately account for the costs LSEs would incur by building replacement generation in response to the potential shutdown of lignite capacity.

This timeline downwardly biases the cost of compliance with the regulations because power plants are long term investments, often paid off over a 30-year time period. This means the changes to the resource portfolio in MISO resulting from these rules will affect electricity rates for decades beyond 2035.

Hourly Load, Capacity Factors, and Peak Demand Assumptions

Hourly load shapes and wind and solar generation were determined using data for the entire MISO region obtained from EIA's Hourly Grid Monitor. Load shapes were obtained for 2019, 2020, 2021, and 2022. [75] These inputs were entered into the model to assess hourly load shapes and assess possible capacity shortfalls in 2035 using each of the historical years.

Capacity factors used for wind and solar facilities were adjusted upward to match EPA assumptions that new wind and solar facilities will have capacity factors as high as 42.2 percent and 24.7 percent, respectively. These are generous assumptions because the current MISO-wide capacity factor of existing wind turbines is only 36 percent, and solar is 20 percent.

Our analysis upwardly adjusted observed capacity factors to EPA's estimates despite the fact that EPA's assumptions for onshore wind are significantly higher than observed capacity factors reported from Lawrence Berkeley National Labs, which demonstrates that new wind turbines entering operation since 2015 have never achieved annual capacity factors of 42.2 percent (See Figure D-12).[76]

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[75] Energy Information Administration, "Hourly Electric Grid Monitor," Accessed August 12, 2022, https://www.eia.gov/ electricity/gridmonitor/dashboard/electric_overview/balancing_authority/MISO

[76] Lawrence Berkely National Labs, "Wind Power Performance," Land Based Wind Report, Accessed July 27, 2023, https://emp.lbl.gov/wind-power-performance.

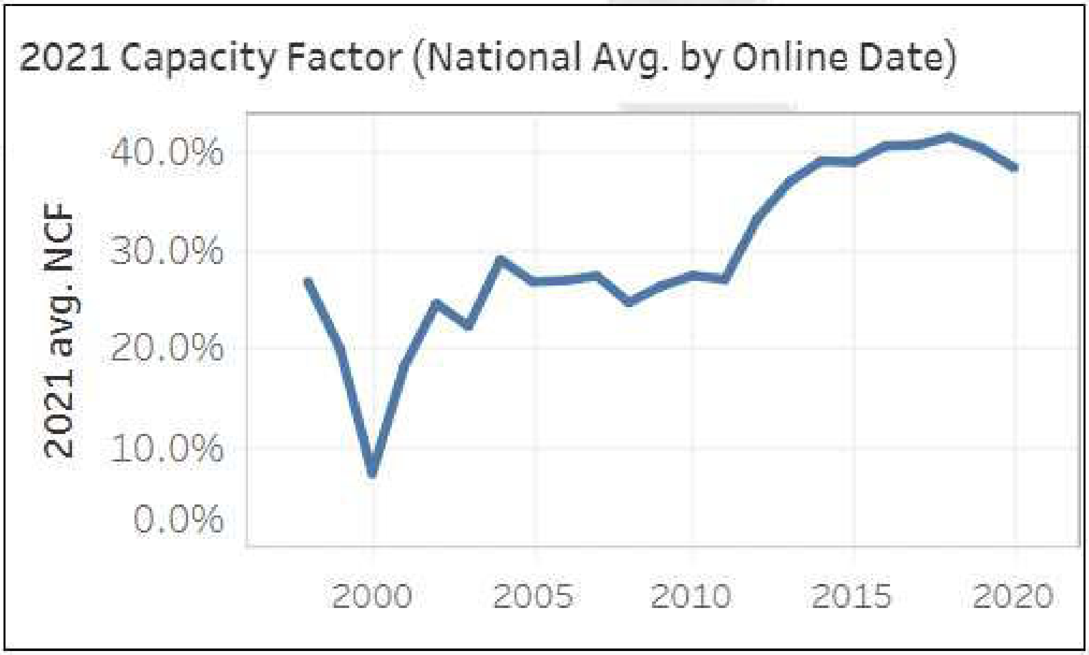

Figure D-12. This *figure shows capacity factors for U.S. onshore wind turbines by the year they entered service. In no year do these turbines reach EPA's assumed 42.2 percent capacity factor on an annual basis.*

Another generous assumption is that we did not hold natural gas plants accountable to other EPA rules, such as the Carbon Rule, that may be in effect in addition to the MATS rule and would cap natural gas generators at 49 percent capacity factors to avoid using carbon capture and sequestration or co-firing with hydrogen. Doing so would have resulted in even more capacity shortfalls.

Line Losses

Line losses are assumed to be 5 percent of the electricity transmitted and distributed in the United States based on U.S. on EIA data from 2017 through 2021.[77]

Value of Lost Load

The value of lost load (VoLL) is a monetary indicator *expressing the costs associated with an interruption of electricity supply*, expressed in dollars per megawatt hour (MWh) of unserved electricity.

[77] Energy Information Administration, "How Much Electricity is Lost in Electricity Transmission and Distribution in the United States," Frequently Asked Questions, https://www.eia.gov/tools/faqs/faq.php?id=105&t=3

Our analysis uses a conservative midpoint estimate of $14,250 per MWh for VoLL. This value is higher than MISO's previous VoLL estimate of $3,500 per MWh, but significantly lower than the Independent Market Monitor's suggested estimate of $25,000 per MWh.[78]

Plant Retirement Schedules

Our modeling utilizes announced coal and natural gas retirement dates from U.S. EIA databases and announced closures in utility IRPs using a dataset collected by NERA economic consulting.

Plant Construction by Type

The resource adequacy and reliability portions of this analysis use MISO Interconnection Queue data to project into the future. EPA capacity values are applied to each newly constructed resource until the MISO system hits its target reserve margin based on EPA's peak demand forecast in its IPM.

Load Modifying Resources, Demand Response, and Imports

Our model allows for the use of 7,875 MW of Load Modifying Resources (LMRs) and 3,638 MW external resources (imports) in determining how much reliable capacity will be needed within MISO to meet peak electricity demand under the new MATS rules.

Utility Returns

Most of the load serving entities in MISO are vertically integrated utilities operating under the Cost-of-Service model. The amount of profit a utility makes on capital assets is called the Rate of Return (RoR) on the Rate Base. For the purposes of our study, the assumed rate of return is 9.9 percent with debt/equity split of 48.92/51.08 based on the rate of return and debt/equity split of the ten-largest investor-owned utilities in MISO.

Transmission

This analysis assumes the building of transmission estimated at $10.3 billion, which is consistent with MISO tranche 1 for the Status Quo Scenario. For the Full and Partial scenarios, transmission costs are estimated to be $223,913 per MW of new installed capacity to account for the increased wind, solar, storage, and natural gas capacity additions.

Taxes and Subsidies

Additional tax payments for utilities were calculated to be of 1.3 percent of the rate base. The state income tax rate of 7.3 percent was estimated by averaging the states within the MISO region. The

[78] Potomac Economics, "2022 State of the Market Report for the MISO Electricity Markets," Independent Market Monitor for the Midcontinent ISO, June 15, 2023, https://www.potomaceconomics.com/wp-content/uploads/2023/06/2022-MISO-SOM_Report_Body-Final.pdf.

Federal income tax rate is 21 percent. The value of the Production Tax Credit (PTC) is $27.50. The Investment Tax Credit (ITC) 30 percent through 2032, 26 percent in 2033, and 22 percent in 2034.

Battery Storage

Battery storage assumes a 5 percent efficiency loss on both ends (charging and discharging).

Maximum discharge rates for the MISO system model runs were held at the max capacity of the storage fleet, less efficiency losses. Battery storage is assumed to be 4-hour storage, while pumped storage is assumed to be 8-hour storage.

Wind and Solar Degradation

According to the Lawrence Berkeley National Laboratory, output from a typical U.S. wind farm shrinks by about 13 percent over 17 years, with most of this decline taking place after the project turns ten years old. According to the National Renewable Energy Laboratory, solar panels lose one percent of their generation capacity each year and last roughly 25 years, which causes the cost per megawatt hour (MWh) of electricity to increase each year.[79] However, our study does not take wind or solar degradation into account.

Capital Costs, and Fixed and Variable Operation and Maintenance Costs

Capital costs for all new generating units are sourced from the EIA 2023 Assumptions to the Annual Energy Outlook (AOE) Electricity Market Module (EMM). These costs are held constant throughout the model run. Expenses for fixed and variable O&M for new resources were also obtained from the EMM. MISO region capital costs were used, and national fixed and variable O&M costs were obtained from Table 3 in the EMM report.[80]

Discount Rate

A discount rate of 3.76 percent is used in accordance with EPA's assumptions in the IPM.

Unit Lifespans

Different power plant types have different useful lifespans. Our analysis takes these lifespans into account. Wind turbines are assumed to last for 20 years, solar panels are assumed to last 25 years, battery storage for 15 years. Natural gas plants are assumed to last for 30 years.

Repowering

Our model assumes wind turbines, solar panels, and battery storage facilities are repowered after they reach the end of their useful lives. Our model also excludes economic repowering, a growing

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[79] Liam Stoker, "Built Solar Assets Are 'Chronically Underperforming,' and Modules Degrading Faster than Expected, Research Finds," PV Tech, June 8, 2021, https://www.pv-tech.org/built-solar-assets-are-chronically-underperforming-andmodules-degrading-faster-than-expected-research-finds/.

[80] U.S. Energy Information Administration, "Electricity Market Module," Assumptions to the Annual Energy Outlook 2022, March 2022, https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.

trend whereby wind turbines are repowered after just 10 to 12 years to recapture the wind Production Tax Credit (PTC). This trend will almost certainly grow in response to IRA subsidies.

EPA does not appear to take repowering into consideration because the amount of existing wind on its systems never changes. If our understanding of EPA's methodology is accurate, this a large oversight that must be corrected.

Fuel Cost Assumptions

Fuel costs for existing power facilities were estimated using FERC Form 1 filings and adjusted for current fuel prices.[81,82] Fuel prices for new natural gas power plants were estimated by averaging annual fuel costs within the MISO region according to EPA.[83] Existing coal fuel cost assumptions of $17.82 per MWh were based on 2020 FERC Form 1 filings.

Inflation Reduction Act (IRA) Subsidies

Our analysis assumes all wind projects will qualify for IRA subsidies and elect the Production Tax Credit, valued at $27.50 per MWh throughout the model run. Solar facilities are assumed to select the Investment Tax Credit in an amount of 30 percent of the capital cost of the project.

Appendix 2: Capacity Retirements and Additions in Each Scenario

This section details the capacity additions and retirements in the MISO region under each scenario.

Status Quo scenario: The Status Quo scenario results in the retirement of 28,756.8 MW of coal resources, 7,852 MW of natural gas capacity, and 462 MW of petroleum capacity. Additions in the Status Quo scenario consist of 4,306 MW of natural gas, 19,436 MW of wind, 29,652 MW of solar, and 3,304 MW of storage.

Annual retirement and additions can be seen in Figure D-13 below.

[81] Trading Economics, "Natural Gas," https://tradingeconomics.com/commodity/natural-gas.
[82] https://data.nasdaq.com/data/EIA/COAL-us-coal-prices-by-region
[83] U.S. Energy Information Administration, "Open Data," https://www.eia.gov/opendata/v1/qb.php?category=40694&sdid=SEDS.NUEGD.WI.A

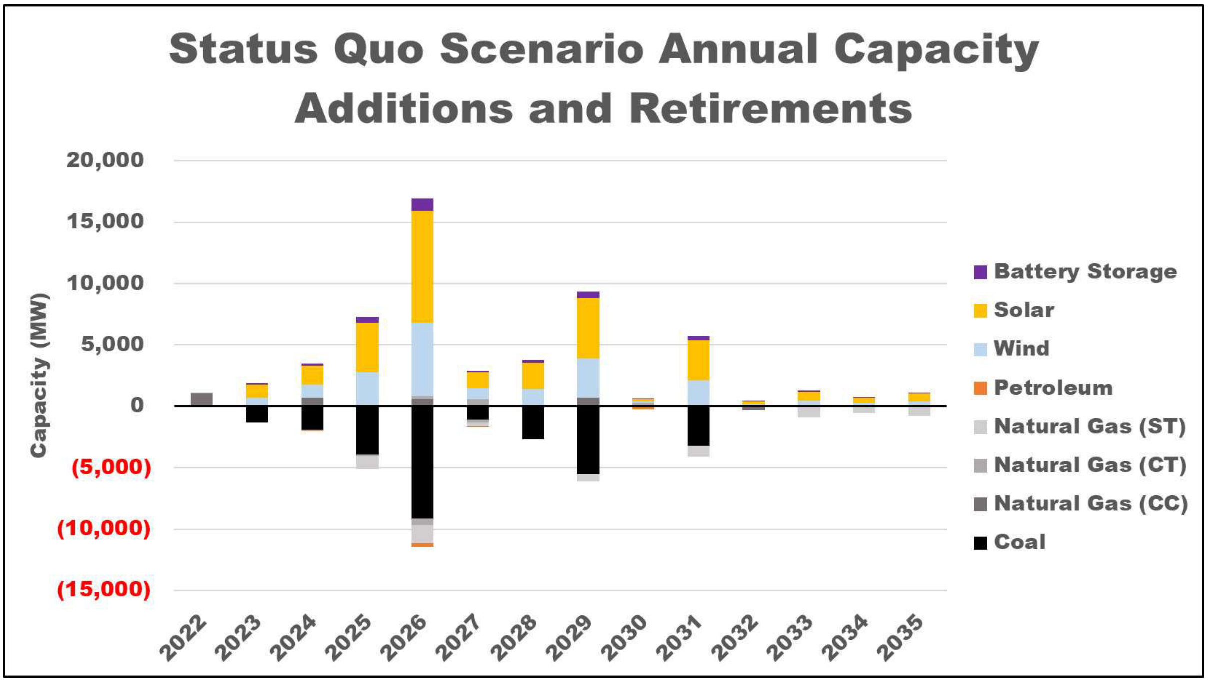


Figure D-13. This graph shows the annual capacity additions and subtractions needed to maintain resource adequacy using EPA's capacity accreditation metrics.

Partial scenario: The Partial scenario results in the retirement of 29,908 MW of coal resources, 7,852 MW of natural gas capacity, and 462 MW of petroleum capacity. To replace this retired capacity, additions in the Partial scenario consist of 4,306 MW of natural gas, 20,451 MW of wind, 31,201 MW of solar, and 3,477 MW of storage (see Figure D-14). The incremental closure of 1,151 MW of lignite capacity results in an incremental increase in a replacement capacity of 1,015 MW wind, 1,549 MW solar, and 173 MW storage (see Figure D-15).[84]

[84] Replacement capacity is more than the retiring 1,151 MW of coal capacity because intermittent resources like wind and solar have lower capacity values than coal capacity.

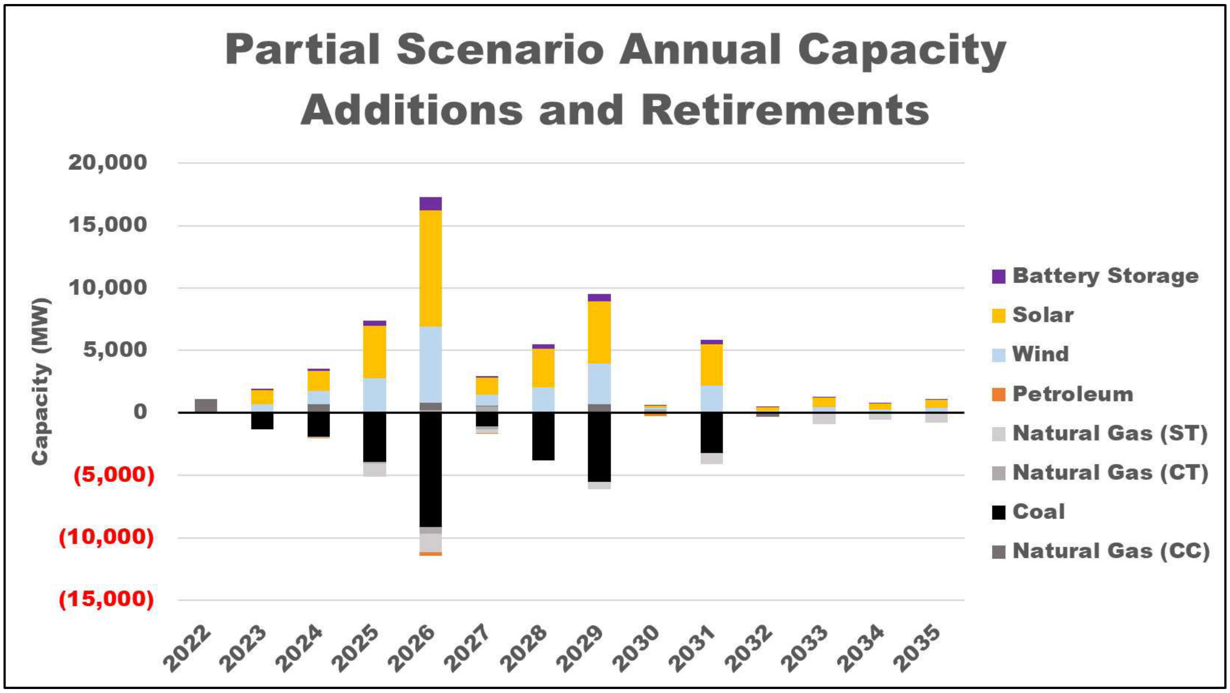


Figure D-14. This graph shows the annual capacity additions and subtractions needed to maintain resource adequacy using EPA's capacity accreditation metrics.

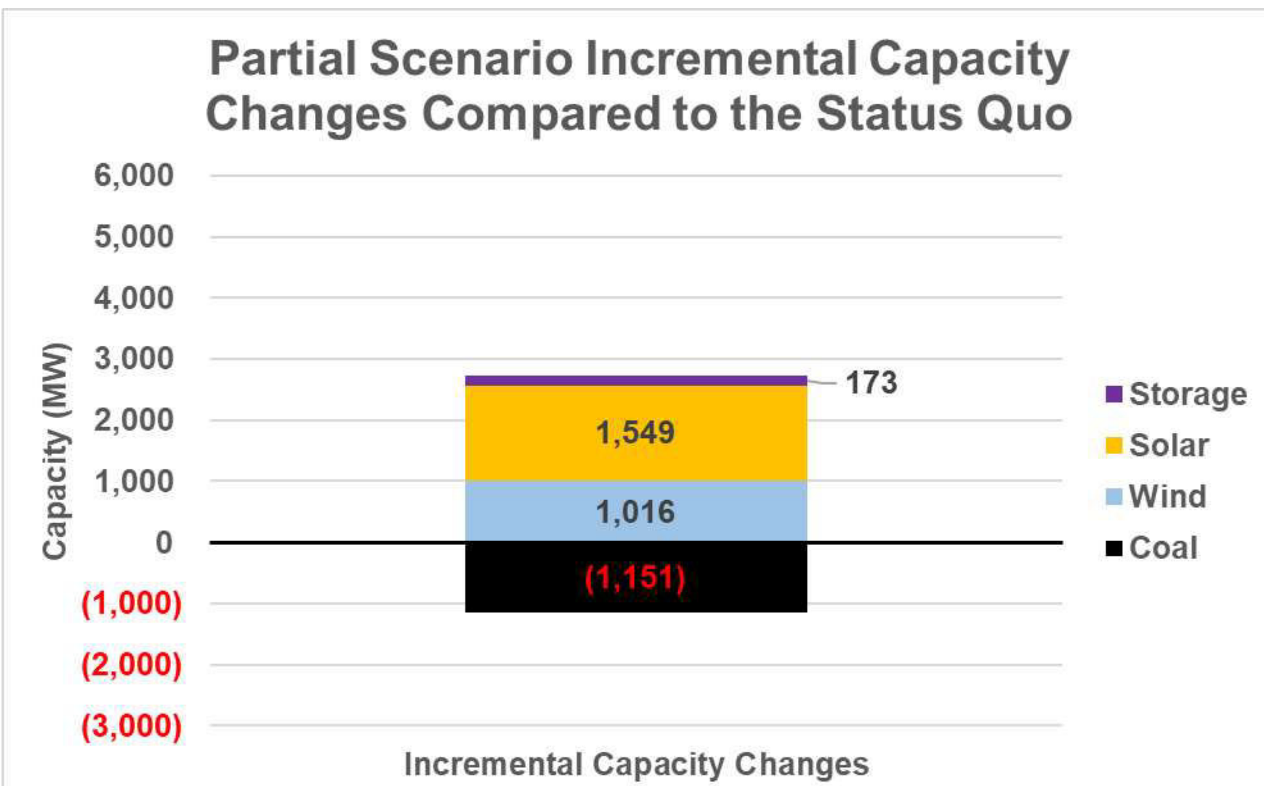


Figure D-15. This figure shows the incremental capacity retirements and additions in the MISO region under the Partial scenario.

Full Scenario: The Full scenario results in the retirement of 31,021 MW of coal resources, 7,852 MW of natural gas capacity, and 462 MW of petroleum capacity. To replace this retired capacity, additions in the Full scenario consist of 4,306 MW of natural gas, 21,433 MW of wind, 32,700 MW of solar, and 3,644 MW of storage (see Figure D-16). The incremental closure of 2,264 MW of lignite capacity results in an incremental increase in a replacement capacity of 1,997 MW wind, 3,048 MW solar, and 304 MW storage, compared to the Status Quo scenario (see Figure D-17).

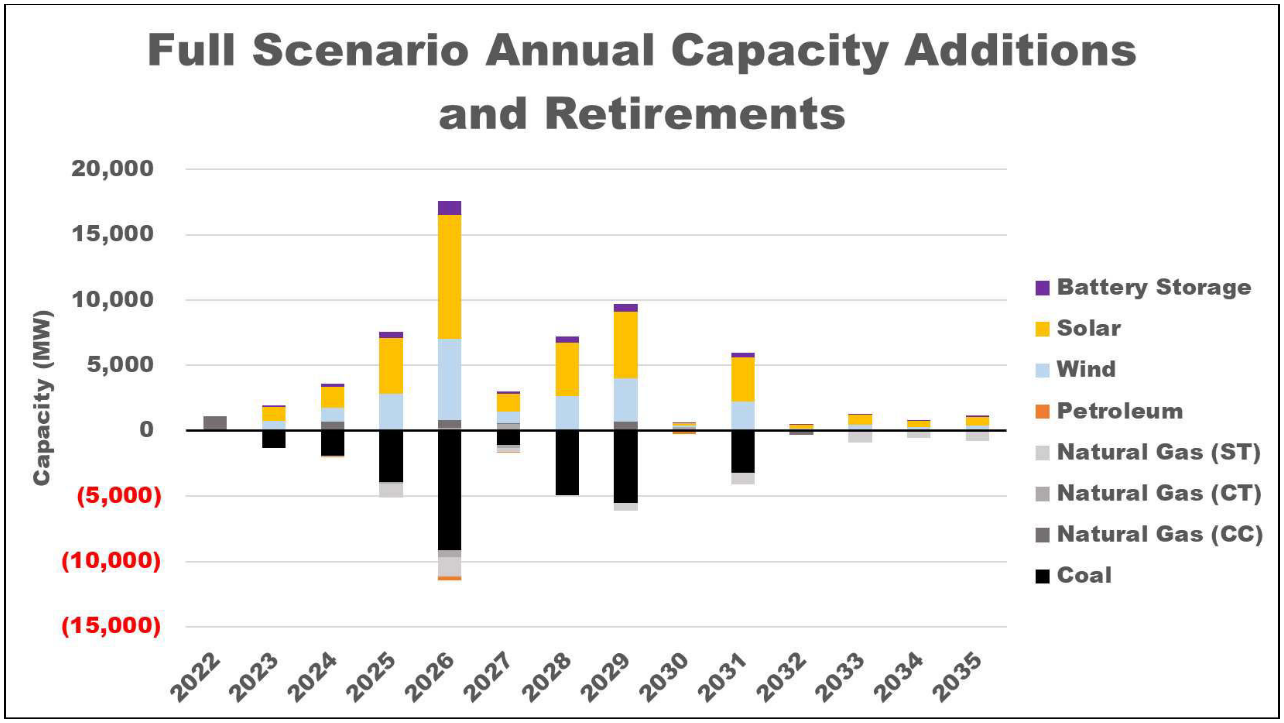


Figure D-16. This graph shows the annual capacity additions and subtractions needed to maintain resource adequacy using EPA's capacity accreditation metrics.

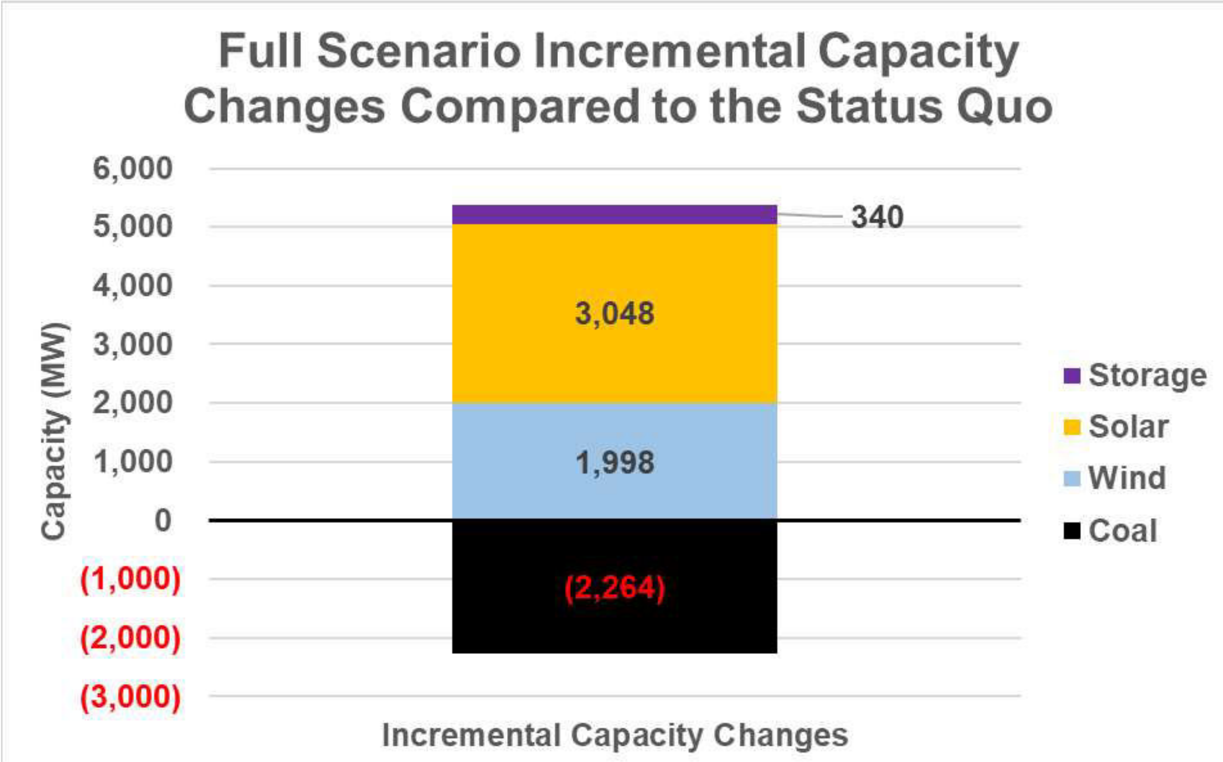


Figure D-17. This figure shows the incremental capacity closures and additions in the Full scenario.

Figure D-18 shows the capacity retirements and additions in the Partial and Full scenarios.

Comparison:

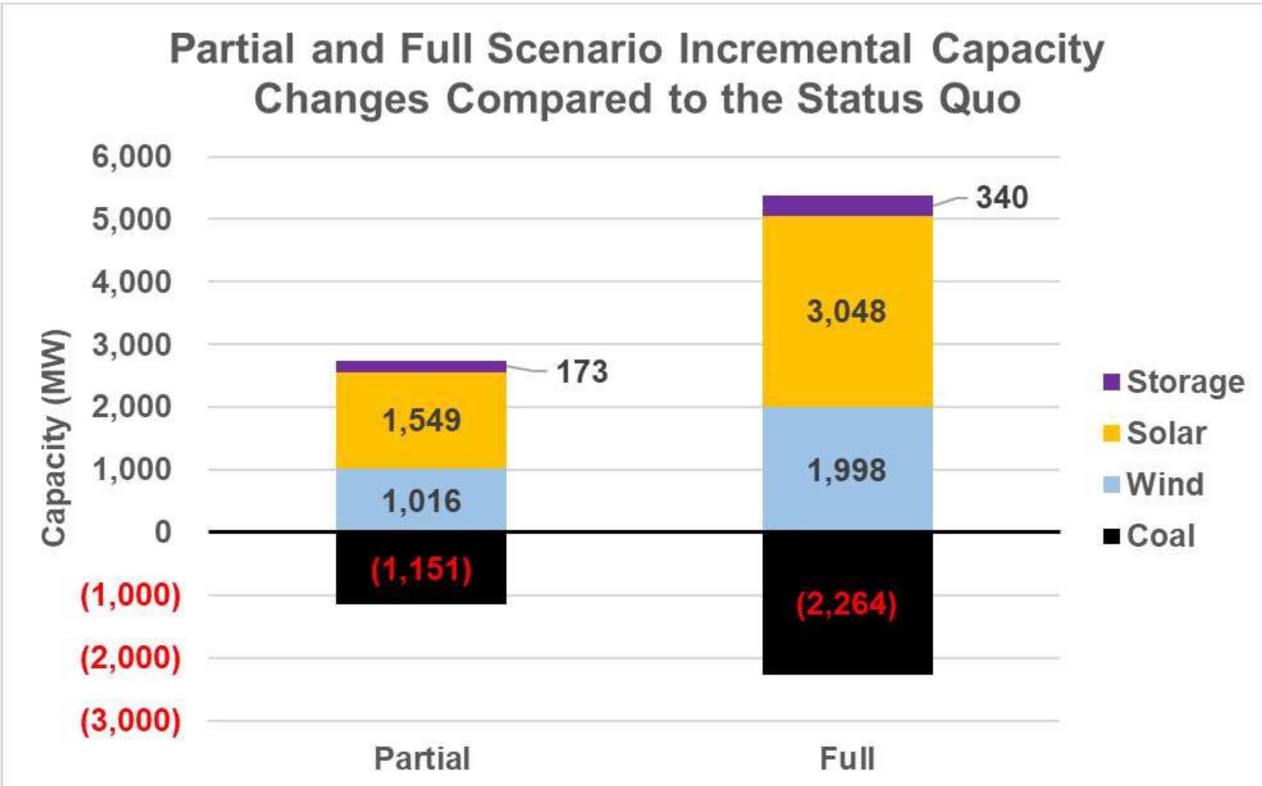


Figure D-18 comparison. This figure demonstrates the incremental retirements and additions in each scenario.

Appendix 3: Replacement Capacity Based on EPA Methodology for Resource Adequacy

The capacity selected in our model to replace the retiring resources is based on two main factors. The first factor is the MISO interconnection queue, which is predominantly filled with solar and wind projects and a relatively small amount of natural gas. The second factor is the EPA's resource adequacy (RA) accreditation values in the Integrating Planning Model's (IPM) Proposed Rule Supply Resource Utilization file and Post-IRA Base Case found in the Regulatory Impact Analysis.

The IMP assumes a capacity accreditation of 100 percent for thermal resources, and variable intermittent technologies (primarily wind and solar) receive region-specific capacity credits to help meet target reserve margin constraints. Due to their variability, resources such as wind and solar received a lower capacity accreditation when solving for resource adequacy (see Table D-4).

EPA Integrated Planning Model

Capacity Accreditation in MISO

Resource	Capacity Value
Existing Wind	19%
Existing Solar	55%
New Onshore Wind 2035	17%
New Solar 2035	52%
Thermal	100%
Battery Storage	100%

Table D-4. This figure shows the capacity values for each resource based on EPA's estimates in its IPM.

In order to determine whether the available blend of power generation sources will be able to meet projected demand, each available generation source is multiplied against its capacity value, and the available resources are then "stacked" to determine if there is enough accredited power generation capacity to meet projected demand and maintain resource adequacy.

It should be noted that EPA's accreditation values from the IPM are generous compared to the accreditation values given by RTOs. For example, in the MISO region, grid planners assume that dispatchable thermal resources like coal, natural gas, and nuclear power plants will be able to produce electricity 90 percent of the time when the power is needed most, resulting in a UCAP rating of 90 percent. In contrast, MISO believes wind resources will only provide about 18.1 percent of their potential output during summer peak times, and solar facilities will produce 50 percent of their potential output. This report uses the generous capacity values provided by EPA; however, if the capacity values used by the RTOs were to be utilized, the projected energy shortfalls and blackouts would be even worse.

Appendix 4: Resource Adequacy in Each Scenario

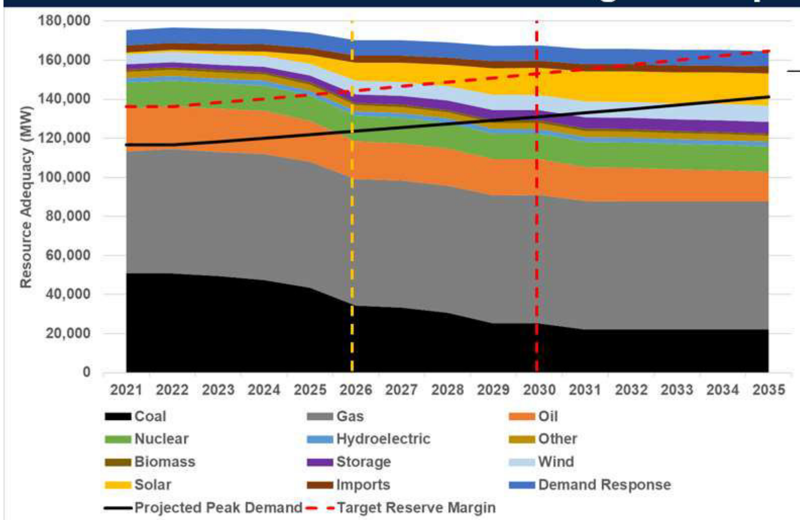
We performed a Resource Adequacy analysis on each of the three scenarios modeled to determine the potential impact to grid reliability in MISO region if implementation of the MATS Rule results in the forced retirement of lignite power plants.

Status Quo scenario

Under the Status Quo scenario, there is enough dispatchable capacity in MISO to meet the projected peak demand and target reserve margin established by EPA in the RIA documents

Proposed Rule Supply Resource Utilization file until the end of 2025, shown in the black font in the table in Figure D-19.[85]

Status Quo Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	109%
2028	14%	4%	106%
2029	17%	4%	100%
2030	16%	4%	98%
2031	18%	4%	94%
2032	18%	4%	92%
2033	18%	4%	90%
2034	18%	4%	89%
2035	18%	4%	87%

Estimated firm capacity using EPA's accreditation values for wind, solar, storage, and thermal resources (100%). EPA assumes a 16.8 percent reserve margin. Different than MISO cleared UCAP (unforced [accredited] capacity). Red indicates intermittent generation is necessary to meet Target Reserve Margins. The rest of the reserve margin not covered in the table consists of load modifying resources.

- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2029: Reserve margin depends on W/S/B*
- *2030 – 2035: Peak Demand depends on W/S/B*

Figure D-19. By 2030, MISO will rely on wind, solar, and battery storage to meet its projected peak demand and target reserve margin.

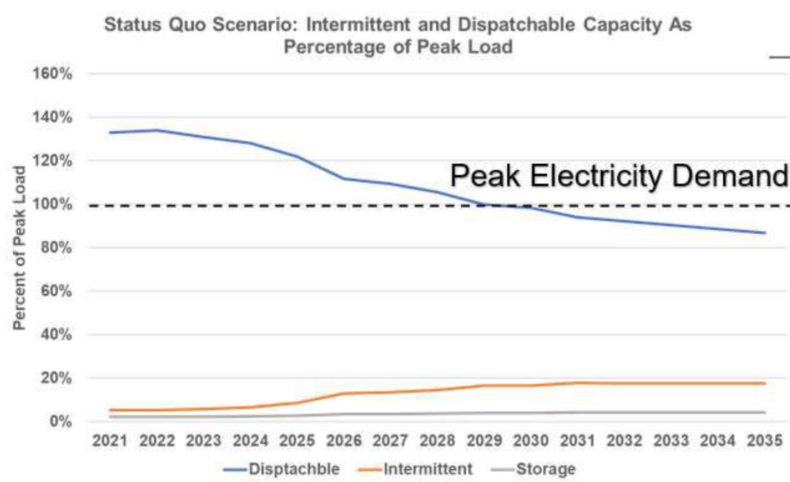
Beginning in 2026, MISO becomes reliant upon wind, solar, imports, or demand response (DR) to meet its target reserve margin, but the RTO still has enough dispatchable capacity to meet its projected peak demand. By 2030, the MISO region will rely on thermal resources and 4-hour battery storage to meet its peak demand, and by 2031 the region will no longer have enough dispatchable capacity or storage to meet its projected peak demand, and it will rely exclusively on non-dispatchable resources and imports to meet its target reserve margin.[86]

The trend of falling dispatchable capacity relative to projected peak demand can be seen more clearly in Figure D-20 below. By 2035, dispatchable capacity consisting of thermal generation and battery storage will only be able to provide 91 percent of the projected peak demand, necessitating the use of wind and solar to maintain resource adequacy.

[85] Analysis of the Proposed MATS Risk and Technology Review (RTR) | US EPA, https://www.epa.gov/power-sector-modeling/analysis-proposed-mats-risk-and-technology-review-rtr

[86] While battery storage is considered dispatchable in this analysis for the sake of simplicity, battery resources are not a substitute for generation because as grids become more reliant upon wind and solar, battery resources may not be sufficiently charged to provide the needed dispatchable power.

Status Quo Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Estimated firm capacity using EPA's accreditation values for wind, solar, storage (100%), and thermal resources (100%).

Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	109%
2028	14%	4%	106%
2029	17%	4%	100%
2030	16%	4%	98%
2031	18%	4%	94%
2032	18%	4%	92%
2033	18%	4%	90%
2034	18%	4%	89%
2035	18%	4%	87%

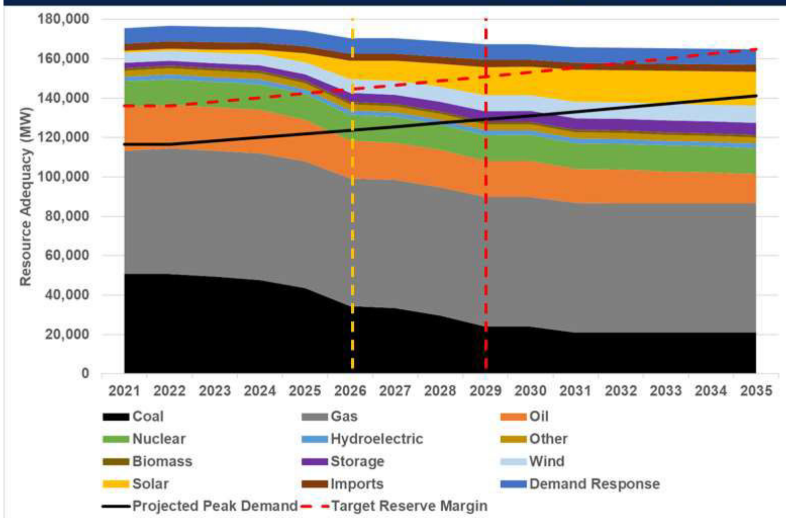
- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2029: Reserve margin depends on W/S/B*
- *2030 – 2035: Peak Demand depends on W/S/B*

D-20. By 2035, dispatchable generators will only constitute 87 percent of projected peak demand, with storage accounting for four percent of peak demand capacity.

Partial scenario

Like the Status Quo Scenario, there is enough dispatchable capacity in MISO under the Partial scenario to meet the projected peak demand and target reserve margin established by EPA in the RIA documents Proposed Rule Supply Resource Utilization file until the end of 2025, shown in the black font in the table in Figure D-21.

Partial Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	109%
2028	15%	4%	105%
2029	17%	4%	99%
2030	17%	4%	98%
2031	18%	4%	93%
2032	18%	4%	92%
2033	18%	4%	90%
2034	18%	4%	88%
2035	18%	4%	86%

Estimated firm capacity using EPA's accreditation values for wind, solar, storage (100%), and thermal resources (100%). EPA assumes a 16.8 percent reserve margin. Different than MISO cleared UCAP (unforced [accredited] capacity). Red indicates intermittent generation is necessary to meet Target Reserve Margins. The rest of the reserve margin not covered in the table consists of load modifying resources.

- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2028: Reserve margin depends on W/S/B*
- *2029 – 2035: Peak Demand depends on W/S/B*

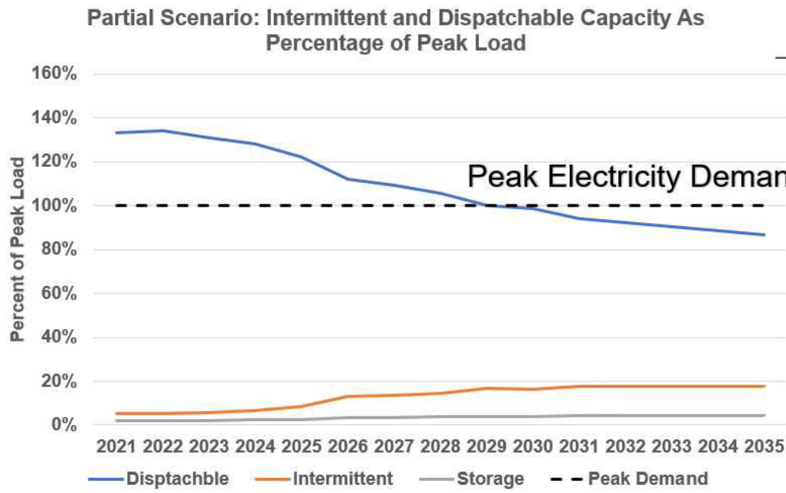
Figure D-21. By 2029, MISO will rely on wind, solar, and battery storage to meet its projected peak demand and target reserve margin.

MISO becomes reliant upon wind, solar, imports, or demand response (DR) to meet its target reserve margin in 2025, but the RTO still has enough dispatchable capacity to meet its projected peak demand. The percentage of MISO's projected peak demand that will be met by dispatchable resources in 2028 declines from 106 percent in the Status Quo scenario to 105 percent in the Partial scenario, reflecting the loss of 1,151 MW of lignite power plants in North Dakota.

In this scenario, the MISO region will no longer have enough dispatchable capacity to meet its projected peak demand in 2029, a year earlier than the Status Quo scenario, and it will rely on non-dispatchable resources, imports, or storage to meet its target reserve margin.

The trend of falling dispatchable capacity relative to projected peak demand can be seen more clearly in Figure D-22 below. By 2035, dispatchable capacity will only be able to provide 86 percent of the projected peak demand.

Partial Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	109%
2028	15%	4%	105%
2029	17%	4%	99%
2030	17%	4%	98%
2031	18%	4%	93%
2032	18%	4%	92%
2033	18%	4%	90%
2034	18%	4%	88%
2035	18%	4%	86%

Estimated firm capacity using EPA's accreditation values for wind, solar, storage (100%), and thermal resources (100%).

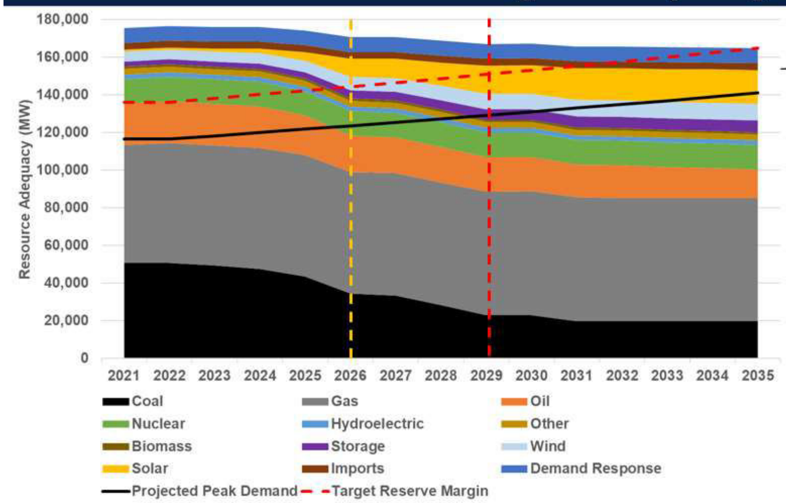
- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2028: Reserve margin depends on W/S/B*
- *2029 – 2035: Peak Demand depends on W/S/B*

Figure D-22. The percentage of peak electricity demand being served by dispatchable resources drops by one percent in 2028, relative to the Status Quo scenario, due to the closure of lignite capacity in MISO due to the MATS rule.

Full scenario

Like the Status Quo scenario and Partial scenario, there is enough dispatchable capacity in MISO under the Full scenario to meet the projected peak demand and target reserve margin established by EPA in the RIA documents Proposed Rule Supply Resource Utilization file until the end of 2025, shown in the black font in the table in Figure D-23.

Full Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	109%
2028	16%	4%	104%
2029	18%	4%	98%
2030	18%	4%	97%
2031	19%	5%	92%
2032	19%	4%	91%
2033	19%	4%	89%
2034	19%	4%	87%
2035	19%	4%	85%

Estimated firm capacity using EPA's accreditation values for wind, solar, storage (100%), and thermal resources (100%). EPA assumes a 16.8 percent reserve margin. Different than MISO cleared UCAP (unforced [accredited] capacity). Red indicates intermittent generation is necessary to meet Target Reserve Margins. The rest of the reserve margin not covered in the table consists of load modifying resources.

- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2028: Reserve margin depends on W/S/B*
- *2029 – 2035: Peak Demand depends on W/S/B*

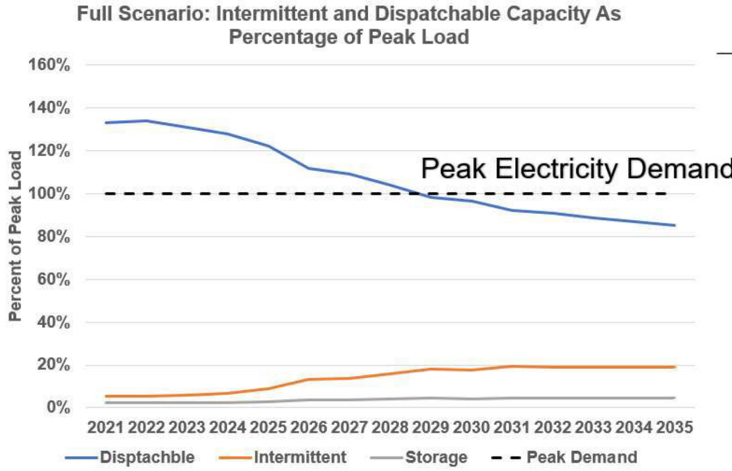
Figure D-23. The amount of dispatchable capacity available to meet projected peak demand in 2028 falls from 106 percent in the Status Quo scenario to 104 percent in the Full scenario, reflecting the closure of all the lignite capacity in MISO that year.

MISO becomes reliant upon wind, solar, imports, or demand response (DR) to meet its target reserve margin in 2025, but the RTO still has enough dispatchable capacity to meet its projected peak demand. The percentage of MISO's projected peak demand that will be met by dispatchable resources in 2028 declines from 106 percent in the Status Quo scenario to 104 percent in the Full scenario, reflecting the loss of 2,264 MW of lignite power plants in North Dakota.

In this scenario, the MISO region will no longer have enough dispatchable capacity to meet its projected peak demand in 2029, a year earlier than the Status Quo scenario, and it will rely on non-dispatchable resources, imports or storage to meet its target reserve margin.

The trend of falling dispatchable capacity relative to projected peak demand can be seen more clearly in Figure D-24 below. By 2035, dispatchable capacity will only be able to provide 85 percent of the projected peak demand, a two percent decline relative to the Status Quo scenario, necessitating the use of wind and solar to maintain resource adequacy.

Full Scenario RA is Maintained by Replacing Retiring Capacity with New Resources Using EPA Capacity Values, But…



Year	% Intermittent	% Storage	% Dispatchable
2023	6%	2%	131%
2024	7%	2%	128%
2025	9%	3%	122%
2026	13%	4%	112%
2027	14%	4%	109%
2028	16%	4%	104%
2029	18%	4%	98%
2030	18%	4%	97%
2031	19%	5%	92%
2032	19%	4%	91%
2033	19%	4%	89%
2034	19%	4%	87%
2035	19%	4%	85%

Estimated firm capacity using EPA's accreditation values for wind, solar, storage (100%), and thermal resources (100%).

- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2028: Reserve margin depends on W/S/B*
- *2029 – 2035: Peak Demand depends on W/S/B*

Figure D-24. The amount of peak demand that can be met with dispatchable resources in 2028 falls from 106 in the Status Quo scenario to 104 in the Full scenario.

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF NORTH DAKOTA, et al. *Petitioners*, v. U.S. ENVIRONMENTAL PROTECTION AGENCY *Respondent*.	Case No. 24-1119

DECLARATION OF
SONJA NOWAKOWSKI

Pursuant to 28 U.S.C. § 1746, I, Sonja Nowakowski, duly affirm under penalty of perjury as follows:

1. I am over 18 years of age, have personal knowledge of the matters set forth herein, and am competent to make this sworn declaration. The facts contained in this sworn declaration are true and accurate and are based on my personal knowledge.

2. I am the Administrator of the Montana Department of Environmental Quality ("DEQ") Air, Energy, and Mining Division, and have personal knowledge of the facts herein in this Declaration. Prior to

joining DEQ in 2021, I worked for the Montana Legislature for 15 years. I served in a nonpartisan capacity as a research analyst in the Legislative Environmental Policy Office and as the Research Director for the Office of Research and Policy Analysis. My nonpartisan work for the Legislature focused on environment and energy policy.

3. As the Administrator of DEQ's Air, Energy, and Mining Division, I am familiar with DEQ permitting processes for coal mining, natural gas fueled electricity generators, coal fueled electricity generators, petroleum refineries, and oil pipelines under their respective substantive permitting statutes. I am also familiar with the requirements for energy planning and procurement in Montana, renewable energy programs in Montana, and Montana's transitioning energy marketplace.

4. Additionally, I am familiar with the U.S. Environmental Protection Agency's National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-Fired Electric Utility Steam Generating Units, also known as the Mercury and Air Toxics Standards or MATS, including the recent revision of these standards, published April 25, 2024.

5. DEQ has a particular interest in averting the disruptive impacts of the Rule on Montana's electricity supply. DEQ houses the state energy bureau, see ARM 17.1.101(3)(c)(iii), which means DEQ has administrative and information sharing obligations concerning Montana's energy supply emergency powers, see §§ 90-4- 301 to -319, MCA; ARM 14.8.401–412; Mont. Disaster and Emergency Services Division, Montana Emergency Response Framework, 35 (April 2022), https://des.mt.gov/Preparedness/MERF-ESF1/MERF_2022/2022-MERF-final.pdf (DEQ is designated the "Primary Agency" for Emergency Support Function 12, which is responsible for coordinating "the state's efforts in the restoration and protection of Montana's critical electricity…systems during and following a disaster or significant disruption.") DEQ is also required to provide comment on Montana public utilities' long term electricity supply planning before the Montana Public Service Commission, § 69-3-1205(3), MCA, which entails an evaluation "of cost-effective means for the public utility to meet the service requirements of its Montana customers[,]" § 69-3-1204(2)(a)(i), MCA.

6. The Rule introduces significant economic uncertainty for important electricity generating units ("EGUs") in the portfolio of electricity resources serving Montana residents and businesses and underpinning the export of electricity to utilities across the pacific northwest region of states. Specifically, the Rule requires upgrades of emission control systems at Colstrip Units 3 and 4 ("Colstrip") in Rosebud County, Montana, and the Yellowstone Energy Limited Partnership (YELP) EGU in Yellowstone County by mid-2027. Colstrip Units 3 and 4 have a combined nameplate generating capacity of 1,480 MW and currently serve residential and commercial customers of NorthWestern Energy in Montana, Montana large industrial customers of Talen Energy, as well as electricity customers across Idaho, Washington, and Oregon. The YELP plant is a 52 megawatt petroleum coke-fueled EGU located in Yellowstone County, Montana. The EGU sells energy to NorthWestern Energy.

7. In comments submitted to the EPA regarding the draft Rule, Colstrip operator Talen Energy cited the capital cost of Rule, noting that upgrading Colstrip to comply with the Proposed Rule is cost-prohibitive, resulting in at least $350,000,000 in capital costs, plus an additional $15

million in annual operating costs. Talen found "the cost effectiveness for Colstrip to install the various controls are significantly higher than EPA's estimate of $39,192/ton, ranging from $73,156/ton to $133,104/ton and from $68,114/ton to $168,132/ton ... The high costs associated with installing, testing, and implementing new controls, coupled with limited time and electric generation for the recovery of such costs, may cause Colstrip to shut down prematurely if the owners deem that it is not economically feasible to install the necessary controls to comply with the proposed fPM standard. A premature shutdown of Colstrip would have significant economic impacts on Montana and beyond and raises serious concerns about grid reliability and transmission, factors that were not considered by EPA in setting the proposed fPM standard." NorthWestern Energy, a 20 percent owner of Colstrip Unit 4, noted that the Rule compliance costs would result in significant costs to Montana customers. NorthWestern Energy also finds, "In addition, if Colstrip is closed in the near term, NorthWestern cannot provide adequate and reliable electrical service for its Montana customers without new replacement baseload capacity. Colstrip currently plays an essential role in baseload capacity for NorthWestern…"

8. EPA dismisses the potential impacts to electric system reliability caused by closure of EGUs that are unable to justify the economic impact of Rule compliance costs by mid-2027. In dismissing those concerns, EPA does not adequately account for direct impacts of the Rule in Montana and the NorthWestern Energy Balancing Authority that would be caused by potential closure of impacted EGUs. Colstrip Units 3 and 4 generated forty one percent of the electricity generated in Montana in 2022, and represented twenty three percent of total installed generating capacity, see Electricity Statistics Tables, Mont. Department of Environmental Quality, accessed at https://deq.mt.gov/files/Energy/Documents/Energy_Statistics/ElectricityTables2023-Updated.xlsx. Colstrip's generating capacity in high load events varies depending on maintenance schedules, and the availability and price of other supply resources. However, during the peak of record setting electricity demand in the NorthWestern Balancing Authority driven by a severe cold weather event in January 2024, coal fired EGUs within the balancing authority generated seventy five percent of the customer electricity demand, see Hourly Electric Grid Monitor, U.S. Energy Information Administration,

https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/NWMT (accessed May 8, 2024). Peak electricity demand for that event hit on January 13, 2024, a day when temperatures dropped below minus 30 degrees Fahrenheit in major population centers served by NorthWestern.

9. The retirement by mid-2027 of Colstrip Units 3 and 4 would require replacing the generating capacity and energy output of those EGUs with a mix of resources capable of reliably meeting comparable energy and capacity requirements, while continuing to meet the growing demand for electricity in Montana. A timeline of three years to conduct the siting, development, construction and commissioning of the energy supply resources, demand side resources, and/or transmission assets required to meet those energy and capacity demands, in accordance with local, state, and federal permitting and interconnection requirements, is inadequate. By comparison, the development by NorthWestern Energy of Yellowstone County Generating Station, a 175 MW natural gas-fueled, reciprocating internal combustion engine generating facility was initiated by NorthWestern in a December 2019 submittal to the Montana Public Service Commission of an RFP for Capacity Resources,

see Montana Public Service Commission, Docket 2019.93.011. The EGU is expected to begin service four and a half years later in mid-2024. The requirement to replace the output of the Colstrip units would come at a time when the Western Electricity Coordinating Council has assessed that, "(s)upply chain disruptions, increasing costs, production obstacles, and an overwhelmed interconnection queue threaten industry timelines to build new resources," see 2023 Western Assessment of Resource Adequacy, Western Electricity Coordinating Council (accessed May 8, 2024), https://www.wecc.org/Administrative/2023%20Western%20Assessment%20of%20Resource%20Adequacy.pdf. The Rule's three-year, mid-2027 compliance timeline threatens the ability of Montana utilities to meet customer demands in accordance with other legal requirements, such as North American Electric Reliability Corporation ("NERC") Standards. See NERC, Reliability Standards (last visited May 3, 2024), https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx.

10. Import transmission capacity to serve loads in Montana is severely constrained during peak load events and would likely be insufficient to serve Montana customers absent the output of EGUs

threatened by the Rule. Relying on existing import transmission capacity to serve peak loads, even if Montana industrial customers and utilities were able to identify adequate out-of-state energy supply, risks the reliability of electricity service in Montana. NorthWestern Energy, which serves as the transmission provider for much of the state, assessed in its comments on the draft Rule: "Relying on transmission lines and interconnections to import the electricity needed to serve such a large portion of our Montana load inherently increases the risk of outages and the resulting failure to serve customers during times of greatest electricity demand," see NorthWestern Corporation Comments, Docket ID No. EPA–HQ–OAR–2018–0794, June 23, 2023, page 14. Furthermore, the development, siting, and permitting of significant new interstate transmission capacity, while essential to serving Montana's long term energy needs and access to markets, is a notoriously complex and time intensive undertaking. New transmission development typically requires acquisition of right of way across public and private land, Tribal government consultations, as well as the coordination of federal, state, and local permitting agencies. At this time, DEQ, which implements the Major Facility Siting Act (MFSA) has not granted a

MFSA certificate for any new interstate transmission projects. New import transmission capacity should not be relied upon as a resource to replace the output of EGUs affected by the Rule within the three-year compliance timeline prescribed by EPA.

11. EPA seems to appreciate the need for potential extensions of the compliance deadline to accommodate the reliability requirements of utilities served by EGUs undertaking compliance activities; the Rule provides for up to a one-year extension of the compliance period for EGUs that are making steps towards compliance. However, no allowance for extensions appears to be provided for EGUs facing retirement due to the uneconomic impact of compliance costs. This approach is inconsistent with regard to the EPA's consideration of electricity reliability impacts from the Rule and further penalizes customers served by impacted EGUs where utilities may be forced to procure or construct alternate energy supply resources on a very tight timeline.

12. Risks to electricity system reliability, driven in part by retirement of dispatchable, high-capacity factor thermal EGUs, is a matter of significant concern. WECC reports that current utility

resource plans in the western interconnect "are not sufficient to meet future demand over each of the next 10 years," and that "starting in 2026, the number and magnitude of demand-at-risk hours increase by orders of magnitude." WECC attributes the growing risks to reliability to increasing variability, "driven primarily by the addition of non-dispatchable variable energy resources (VER), the retirement of dispatchable resources, and the increase in load uncertainty due to extreme weather events," see 2023 Western Assessment of Resource Adequacy, Western Electricity Coordinating Council (accessed May 8, 2024),

https://www.wecc.org/Administrative/2023%20Western%20Assessment%20of%20Resource%20Adequacy.pdf.

Sonja Nowakowski

SONJA NOWAKOWSKI
Dated: May 20, 2024

JERRY PURVIS
DECLARATION OF HARM IN SUPPORT OF MOTION FOR A STAY PENDING REVIEW

1. My name is Jerry Purvis. I am Vice President of Environmental Affairs at East Kentucky Power Cooperative, Inc. (East Kentucky). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. I have 30 years of experience in electrical power generation. I have been employed at East Kentucky since 1994. I hold a bachelor's degree in Chemistry from Morehead State University and a bachelor's degree in Chemical Engineering from the University of Kentucky. I have a Master of Business Administration from Morehead State University. As Vice President, I am responsible for promoting proactive environmental policies, implementing comprehensive compliance strategies, and supporting East Kentucky's sustainability goals. I manage East Kentucky's staff and outside consultants in pursuit of these goals.

3. I am providing this Declaration in support of the motions to stay challenging the U.S. Environmental Protection Agency's (EPA) National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 89 Fed. Reg. 38508 (May 7, 2024), known as the Mercury and Air Toxics Standards Risk and Technology Review (the Final Rule or the MATS RTR).

4. East Kentucky is a not-for-profit electric generation and transmission cooperative headquartered in Winchester, Kentucky. East Kentucky is owned, operated, and governed by its members, who use the energy and services East Kentucky provides. These owner-member cooperatives provide energy to 520,000 homes, farms, and businesses across 87 counties in Kentucky. East Kentucky's purpose is to generate electricity and transmit it to 16 Owner-Member cooperatives that distribute it to retail, end-use consumers (Owner-Members). East Kentucky provides wholesale energy and services to Owner-Member distribution cooperatives through baseload units, peaking units, hydroelectric power, solar panels,

landfill gas to energy units and distributed generation resource power purchases – transmitting power across the rural Kentucky areas via more than 2,900 miles of transmission lines. East Kentucky's Owner-Members' collective customer base is comprised largely of residential customers (93%). And, in 2019, 57% of East Kentucky's owner-member retail sales were to the residential class. Electricity is the primary method for water heating and home heating for this class of customers.

5. East Kentucky is a member of PJM Interconnection (PJM). PJM is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in 13 states and the District of Columbia.

6. East Kentucky is a member of the National Rural Electric Cooperative Association (NRECA). NRECA represents the interests of rural electric cooperatives across the country.

7. Demand for electricity is increasing in Kentucky. East Kentucky predicts increased demand during the time span in which this Final Rule would impact. East Kentucky forecasts net total energy requirements to increase from 13.5 to 16.7 million MWh (megawatt hours), an average of 1.5

percent per year over the 2021 through 2035 period.[1] Residential sales will increase by 0.7 percent per year, and small commercial sales (customers with ≤1000 KVA (kilo-volt-amperes)) will increase by 0.9 percent per year. The greatest area of growth will be for large commercial and industrial sales (customers with >1000 KVA), projected to increase by 3.3 percent per year.

8. East Kentucky is the voice for a substantial number of end users of electricity in its service territory that live in impoverished communities. These communities place a high value on affordable energy costs. East Kentucky's service territory includes rural areas with some of the lowest economic demographics in the United States. In these areas, families are literally faced with a daily choice between food, electricity, and medicine. Of the 87 counties that East Kentucky's Owner-Member cooperatives serve, 40 counties experience persistent poverty, as reported by the USDA.

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[1] East Kentucky Integrated Resource Plan, Load Forecast 2021-2035 (Dec. 2020) (IRP 2020).

9. Many of these hardworking Americans have been plagued by unemployment from mines, trucking companies, restaurants and other businesses. The unemployment rate is 60% higher than the national average. They rely on government assistance to survive; anywhere from 30% to 54% of total income in most of the counties that East Kentucky serves comes from governmental assistance programs. Forty-two percent of these electricity users are elderly (65 years or older). Many are on fixed incomes and reside in energy-leaking mobile homes. Recent brutal cold weather has caused their monthly electric bills to skyrocket. East Kentucky has a strong interest in keeping energy affordable to assist its 16 Owner-Member cooperatives in serving people facing the harsh realities of today's economy.

10. The MATS RTR threatens the viability of one of East Kentucky's essential coal-fired assets. It places burdens on the power sector, as a whole, and causes harm to our customers, including rural families, dependent on affordable, reliable electricity.

EAST KENTUCKY'S IMPACTED ELECTRIC GENERATING UNITS

11. East Kentucky owns electric generating units (affected EGUs) that fall within the Final Rule's scope of coverage and thus must comply with the Final Rule's stringent new filterable particulate matter (fPM) standard for coal-fired units. The Final Rule requires East Kentucky to expend substantial costs to comply with the fPM portion of the Rule that, ultimately, the rural ratepayers in East Kentucky's service area, must bear. Moreover, the Final Rule is so stringent that the margin between compliance and non-compliance is so thin that even a minor glitch would very likely cause a forced outage that would otherwise unnecessarily expose East Kentucky and its ratepayers to performance penalties in PJM and substantial exposure in the energy markets. Given the rapid growth in demand for electricity from large data centers and other new and expanding loads – coupled with the EPA's other chorus of new rules that target greenhouse gas emissions, coal combustion residuals, effluents,

ozone and particulates – the cumulative impact of the Final Rule will be to further jeopardize grid stability and reliability.

12. Spurlock Station, East Kentucky's flagship plant, is located near Maysville, Kentucky on the Ohio River. All four units at Spurlock have state-of-the-art NOx, SO_2, PM, and Hg controls. Spurlock Station combusts bituminous coal.

13. Spurlock Unit 3 is a coal-fired circulating fluidized bed boiler (CFB) unit (278 MW), which is designed to emit less NOx and SO_2 in the combustion process. Unit 3 has a SNCR to control NOx, a dry FGD to control SO_2/SO_3, and a filter fabric baghouse to control fPM. In essence, as fPM passes out of the Unit 3 boiler, it passes through a structure filled with 8,256 fabric bags that collect the fPM for later disposal. The limits for this type of emission are measured in hundredths of a pound of material per million British Thermal Units of energy produced (lb./mmBtu). Unit 3 is adversely affected by the Final Rule.

14. Spurlock Unit 3 has a stellar MATS compliance record with no historical exceedances of MATS Rule requirements. The Final Rule

confirms that the existing fPM and other MATS limits, are sufficiently protective of human health and the environment. Therefore, East Kentucky's existing fPM controls provide ample protection to ensure the communities surrounding Spurlock Station enjoy clean air.

15. East Kentucky has made substantial investments in Spurlock Station due to recent EPA environmental rules, including a conversion to dry bottom ash, ash pond clean closure by removal, and a new waste water treatment system with evaporation to ensure the plant is fully compliant with Effluent Limitation Guidelines (ELGs) and the 2015 Coal Combustion Residuals (CCR) rule. Altogether, EKPC has invested $1.8 billion in environmental control equipment.

16. EKPC is presently evaluating the need for further extraordinary expenditures due to the EPA Rules released on April 25, 2024.[2] Collectively,

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[2] New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39798 (May 9, 2024) (Greenhouse Gas Power Sector Rule); Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR

these rules impose egregious financial impacts on EKPC, its members, and end users. This Final Rule's costs must be considered as cumulative environmental costs that will detrimentally impact the cost to heat and cool the homes of rural ratepayers in disadvantaged communities and to power the job-creating businesses that provide employment to these individuals.

MATS RTR RULE REVISIONS

17. The MATS RTR decreases the limit for fPM from 0.030 lb/mmBtu to 0.010 lb/mmBtu (the New fPM Limitation) – an unprecedented 67% reduction that imposes substantial risks to unit performance in PJM with little to no environmental benefit. The Final Rule

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Surface Impoundments, 89 Fed. Reg. 38950 (May 8, 2024); Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 89 Fed. Reg. 40198 (May 9, 2024); National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 89 Fed. Reg. 38508 (May 7, 2024).

exceeds the point where the law of diminishing returns suggests that the additional limitations are not warranted.

18. The Final Rule also requires adoption of continuous emission monitoring systems (CEMS) as the only method to demonstrate compliance with the New fPM Limitation, eliminating the option to use quarterly stack testing and also eliminating the Low Emitting EGU (LEE) program. These requirements will increase the costs associated with program compliance without offering any substantial benefit beyond what the current measurement and verification procedures already afford.

19. Compliance with the New fPM Limitation and installation of PM CEMS are required on or before three years after the effective date of the Final Rule. To be able to meet these deadlines, East Kentucky and other utilities must begin work now to be in a position to comply.

20. The MATS RTR also eliminates the low rank coal subcategory for lignite-powered facilities and revises the limit for mercury from lignite-fired power plants from 4.0 lb/TBtu to 1.2 lb/TBtu (the New Mercury

Limitation). The New Mercury Limitation does not affect East Kentucky because the cooperative's coal-fired plants do not combust lignite fuels.

THE NEW fPM LIMITATION WILL CAUSE IMMEDIATE AND IRREPARABLE HARM TO EAST KENTUCKY

21. Spurlock Unit 3 is not presently capable of meeting the New fPM Limitation of 0.010 lb/mmBtu on a sustained basis. Although no data exists to confirm that compliance can in fact be achieved, East Kentucky has devised an initial strategy to improve fPM removal performance of the Spurlock Unit 3 baghouse.

22. To attempt to meet the New fPM Limitation, Spurlock Unit 3 must expeditiously begin a study and upgrades to its baghouse (the Baghouse Upgrade Project). The cost of the Baghouse Upgrade Project causes additional financial harm to East Kentucky and its owner-members.

23. Given the requirements associated with designing, permitting, financing and securing state regulatory approval for the Baghouse Upgrade Project, work must begin during the early pendency of this litigation due to the compliance date for the Final Rule.

24. It is unknown to what extent the Baghouse Upgrade Project will improve Unit 3's fPM emission rates. Regardless of the potential improvements of the Project, the 2005-vintage baghouse installed at Unit 3 was not designed to meet 0.010 lb/mmBtu. The baghouse is undersized to achieve the fPM Limitation and must operate flawlessly to attain compliance. In East Kentucky's experience with baghouse operation at CFB units, the Unit 3 baghouse will certainly fail, despite best engineering and maintenance practices, due to the lack of any margin to meet the aggressively low new fPM Limitation.

25. Therefore, East Kentucky anticipates being harmed by increased Unit 3 forced outages, resulting in potential penalties and exposure to market volatility in the PJM market. Lower fPM emission limitations, in general, put environmental control equipment under more stress in the summer and winter on peak days. Since the limit for fPM was reduced immensely (67%), there is little margin for error. **To put the effect of the Final Rule in context, a single hole the size of a human pinky finger in one of over 8,000 fabric filter bags within the baghouse can**

cause an exceedance of the new standard and, thereby, force the unit offline. It is simply unreasonable to think that a baghouse will perform perfectly under every operating condition in every period of the year. Even if Unit 3 and its upgraded baghouse achieve initial compliance with the Final Rule, the new and stricter fPM limitations on peak demand days – when PJM is calling for all available generators to produce power in order to avoid blackouts - stress the fPM controls to the point of a forced outage. Forced outages in PJM are unforgiving and highly penalized with the added injury of having to pay market prices for power during periods when it is least available and, therefore, most expensive. East Kentucky estimated, as an example, the penalty and damages caused by one forced outage event on Spurlock Unit 3 could easily exceed $31 million per seven-day outage. For a non-profit cooperative such as EKPC, an entire year's worth of margins could be wiped out in a single weekend of extreme weather.

Cost of Spurlock Unit 3 Seven Day Outage

PJM Market Pricing Conditions	Cost of Replacement Power for Unit 3	Lost Capacity Payment	PJM PAI Non-Performance Penalty	Total
Winter Average Cost	$1,640,785	$232,066	0	$1,872,851
Summer Average Cost	$1,600,361	$232,066	0	$1,832,427
Winter High Cost	$3,371,164	$232,066	0	$3,503,230
Winter Storm Event	$13,203,225	$232,066	$17,595,000	$31,030,291

Note 1: Winter Average Cost is based on replacement power at an average day-ahead price for January 2023
Note 2: Winter High Cost is based on replacement power at an average 168 highest hours of real-time LMP in January 2024
Note 3: Winter Storm Event is based on replacement power at an average 168 highest hours of real-time LMP in December 2022 around and including Winter Storm Elliott
Note 4: All prices include 7-days of power
Note 5: PJM Performance Assessment Interval (PAI) Non-Performance Penalty is assessed during a reliability event due to certain triggering events identified in the PJM Tariff, such as during a manual load shed event. The cost calculation assumes a 23 Hour PAI event.

26. The table above illustrates that, for an unplanned forced outage in PJM, EKPC could experience up to a $31,030,291 dollar penalty for not showing up as a result from a hole in the baghouse the size of a pinky finger. This illustrates the dissonance between the very marginal environmental impact of the Final Rule and the very real, tangible and irreparable harm that would result from a forced outage coming at an inopportune moment.

27. Of course, the foregoing analysis assumes that replacement power is even available for purchase from the PJM market during a Final

Rule-induced forced outage. PJM has signaled that EPA's new environmental regulations – particularly the Greenhouse Gas Power Sector Rule – will reduce the dispatchable capacity in the PJM system. PJM states, "[I]n the very years when we are projecting significant increases in the demand for electricity, the [Greenhouse Gas Power Sector] Rule may work to drive premature retirement of coal units that provide essential reliability services . . ." Plainly, any unit downtime exacerbates an already precarious reliability situation, especially considering the increasing demand for electricity in Kentucky and elsewhere in the PJM region.

28. East Kentucky, as a non-profit electric cooperative, has limited financial resources to risk PJM penalties of this magnitude, especially when layered with other environmental compliance projects due to EPA's recent rulemaking agenda. All of these projects must take place during the same time period. These costs will place upward pressure on rates for rural customers and impact East Kentucky's ability to supply affordable, reliable energy to customers.

THE MATS RTR CREATES GRID RELIABILITY CONCERNS

29. Compliance costs and increased maintenance needs associated with the Final Rule create a significant risk of energy reliability and economic hardship.

30. Spurlock Unit 3 would not be available during forced outage time periods because the baghouse is not designed to provide sufficient margin for compliance with the New fPM Limitation, such that even a pinky-sized hole in one of the baghouse bags would cause an exceedance. During these time periods, existing generation resources may not be adequate in Kentucky to sustain the grid. Multiple new EPA environmental regulations directly and profoundly impact generation resources in Kentucky, causing multiple unit retirements in a short time frame. This Final Rule makes it more likely that Spurlock Unit 3 will be forced off-line when PJM depends upon it the most, contributing to cumulative reliability concerns.

31. If the interruption of power delivery from a grid failure occurs, East Kentucky, its members, the economy, and the public health of end

users in its service territory would be immediately harmed. Kentuckians rely on electricity to heat and cool their homes. Affordable and consistent power supports essential health services to the elderly, infirm, and to vulnerable individuals with chronic health conditions. Evidence from the grid failure during winter storm Elliott in the PJM area shows the documented health impacts and morbidity caused by those events. Other concrete damages would occur such as business shutdowns, food spoilage, property damage, and lost labor productivity.

32. Further economic development in Kentucky is at risk without the ability to provide sufficient energy to support new factories, data centers, and other infrastructure necessary to attract industry, and, in turn, create new jobs. Energy powers the economy from which the government derives tax revenues. The MATS RTR imposes tremendous new risks on East Kentucky and the power grid while offering benefits that are, at best, marginal.

SUMMARY OF HARM TO EAST KENTUCKY

33. At this time, Spurlock Unit 3 cannot currently meet the New fPM Limitation on a sustained basis.

34. East Kentucky must immediately expend several million dollars to determine how Spurlock Unit 3's fPM performance can be improved. Irrespective of the Project improvements, the Unit 3 baghouse's design provides virtually no compliance margin. However, the reality of the current state-of-the-art dictates that there will be failures from time to time. A very small hole in a single bag is the margin of error between compliance and enormous risk of exposure to PJM performance penalties and energy market exposures.

35. East Kentucky is harmed by the MATS RTR because it must expend financial resources to commence the Baghouse Upgrade Project sooner than later to lower its fPM emissions and to meet the MATS RTR compliance deadline. The Final Rule's unyielding mandates will result in less reliability and greater costs with no significant improvement in air quality.

36. These costs cannot be deferred or delayed until the courts reach a final determination on the merits of the Petition for Review and all appeals are exhausted. East Kentucky expects that could take several years. If the Final Rule remains in effect while challenges are pending, East Kentucky will have no choice but to incur significant non-refundable compliance costs as well as to shoulder the many other substantial, immediate, and irreparable harms described above. The consumers who rely on power generated by East Kentucky might find themselves with less reliable power or without the means to pay for it or both.

* * * *

[Signature Follows on Next Page]

I declare under penalty of perjury that the foregoing is true and correct.

Jerry Purvis

Dated: 6/5/2024

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE OF NORTH DAKOTA, *et al.*,	§	
	§	
Petitioners,	§	
	§	
v.	§	No. 24-1119
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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *et al.*	§	
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Respondents.	§	

DECLARATION OF D. W. RICKERSON, P.E., SENIOR VICE PRESIDENT AND CHIEF OPERATING OFFICER FOR ELECTRIC RELIABILITY COUNCIL OF TEXAS, INC.

I, D. W. Rickerson, P.E., declare as follows:

1. I am the Senior Vice President and Chief Operating Officer for Electric Reliability Council of Texas, Inc. (ERCOT), where I am responsible for overseeing grid and market operations, system planning, and weatherization. I am providing this declaration on behalf of ERCOT.

2. ERCOT is the independent system operator (ISO) designated by the Public Utility Commission of Texas (PUCT) for the purposes of managing the operation and planning of the ERCOT transmission grid, which serves the majority of customers in the State of Texas. ERCOT is also responsible for operating the wholesale market for electricity in the ERCOT region and facilitating customers' choices of retail providers of electricity.

3. Texas law assigns ERCOT a number of critical functions, including the fundamental responsibility to ensure the reliability and adequacy of the bulk power system in the ERCOT region. ERCOT's most basic function in ensuring system reliability is to individually dispatch hundreds of generators located across the system to match the system demand at every moment of every day while observing both the physical and stability limits of the transmission network that transfers power from generators to consumers.

4. In its role as ISO, ERCOT also conducts forward-looking assessments to evaluate the adequacy of generation resources to serve future system demand and to identify and plan transmission lines and other facilities to ensure that power from generation facilities can be reliably transported to serve customer demand.

5. It is my understanding that the U.S. Environmental Protection Agency (EPA)'s final rule revising the National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-Fired Electric Utility Steam Generating Units (EGUs) (hereinafter, "the rule") was published in the Federal Register on May 7, 2024 and will become effective on July 8, 2024.

6. It is also my understanding that the rule reduces the level of allowable emissions of filterable particulate matter (fPM) from coal-fired power plants by two thirds and reduces the level of allowable emissions of mercury from lignite-fired

power plants by 70 percent. Further, it is my understanding that these lower emissions limits would apply beginning July 6, 2027.

7. I am providing this declaration to express my concerns that the rule could lead to retirements of lignite-fired EGUs and potentially other coal-fired EGUs, which could impair ERCOT's ability to ensure reliable electric service for the citizens of Texas.

8. In recent years, the ERCOT region has experienced significant growth of renewable generation, including wind and solar technologies. As of today's date, ERCOT is the national leader in utility-scale solar and wind generating capacity, with approximately 24,000 MW of solar capacity and 39,000 MW of wind capacity installed.

9. While solar and wind generation technologies provide significant amounts of low-marginal-cost power, they are not dependable sources because they produce power only in proportion to the amount of available sunlight and wind. ERCOT cannot dispatch solar generators at nighttime or wind generators when the wind is not blowing. ERCOT must rely on other dispatchable generation resources to serve the system demand that cannot be consistently served by renewable sources of power.

10. One relatively new form of dispatchable power is electric energy storage, which typically exists in the form of utility-scale batteries. As with

renewable energy, ERCOT has experienced a significant growth in the amount of battery storage in recent years, growing from approximately 150 MW in 2019 to over 6,000 MW today, with another 10,000 MW of batteries expected to be added by the end of summer 2025. ERCOT expects this long-term trend in battery storage growth to continue. However, unlike gas-fired and coal-fired generation sources, energy storage systems are inherently duration-limited because they can store only a finite amount of power. Even with a tripling of the current capacity, batteries will only be capable of supplying a small portion of the grid's energy needs for a few hours at a time. Consequently, ERCOT will continue to need to rely on electricity from all available gas-fired and coal-fired EGUs to generate electricity when energy from renewable sources and battery storage is insufficient to serve the grid.

11. While the rule does not prohibit operation of lignite-fired EGUs, the rule's lowering of allowed mercury emissions effectively requires owners of these EGUs to install technologies to limit emissions of mercury. I am concerned that owners of lignite-fired EGUs may choose to retire those EGUs rather than pay the significant cost for the plant controls required to comply with the rule.

12. Similarly, I am concerned that the reduced level of allowable fPM could lead coal-unit owners, including owners of lignite-fired EGUs that are subject to the lower mercury threshold, to retire those units rather than install the technologies needed to comply with the rule.

13. Because a material risk exists that coal-fired EGUs—and especially lignite-fired EGUs—in the ERCOT region could retire as a result of the rule, I believe the rule increases the risk that the ERCOT region will experience energy shortages in the future.

14. ERCOT has already identified significant challenges in meeting its future demand without the additional impacts of the rule. ERCOT is in the midst of an explosion of new electricity demand, with average summer peak demand growth of 7.8% since 2021, far exceeding average historical annual peak demand growth rates of approximately 1.5%. And load growth is now expected to rise even higher in the future. Based on recent utility demand forecasts, ERCOT now anticipates its peak load to exceed 152,000 MW by 2030, significantly outpacing its all-time peak demand record of 85,500 MW set in 2023 with an average annual rate of growth of 11.1% between now and 2030.

15. With these significant rates of anticipated demand growth, the ERCOT region will require even more dispatchable, unlimited-duration generation resources in the future, along with associated transmission infrastructure, to fill in gaps when sufficient renewable generators and battery storage systems are not available to produce energy. Even at this time, ERCOT is uncertain whether it will have enough generation resources to serve this future load. However, eliminating lignite-fired EGUs—which currently constitute about 6,500 MW—or potentially all coal-fired

power plants—which currently constitute about 14,000 MW—would only further impair ERCOT's ability to ensure sufficient generation supply to meet demand at all times. If insufficient generation is available at any time, ERCOT must direct utilities to disconnect customers from the grid. This can have significant consequences for consumers who depend on electricity for critical, life-sustaining functions during periods of extreme weather.

16. For these reasons stated above, I believe the rule poses an unacceptable risk to the reliability of the ERCOT System.

17. I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

Executed on May 24, 2024.

DW Rickerson

D. W. Rickerson, P.E.
Senior Vice President and Chief Operating Officer
Electric Reliability Council of Texas, Inc.

<u>**DECLARATION OF STACY L. TSCHIDER**</u>

1. I am the Chief Executive Officer for Rainbow Energy Center, LLC ("Rainbow"). As CEO, I oversee and direct all aspects of operations and development at Rainbow. Rainbow is the owner and operator of Coal Creek Station, a 1,151 MW lignite coal-fired power plant near Underwood, North Dakota, and participates in the Midcontinent Independent System Operator ("MISO") market as an Independent Power Producer. I provide this declaration in support of the motion to stay the rule promulgated on April 25, 2024 by the U.S. Environmental Protection Agency ("EPA" or "Agency") and officially published in the *Federal Register* on May 7, 2024. *See* National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 89 Fed. Reg. 38,508 (May 7, 2024) ("Final Rule").

2. The Final Rule requires that Rainbow install costly, duplicative, and unnecessary controls at its Coal Creek Station coal-fired power plant. First, installation of controls to comply with emission limits for mercury ("Hg") and the newly required particulate matter continuous emission system ("PM CEMS") to monitor filterable particulate matter ("fPM") emissions will require immediate costly capital expenditures. Second, the fPM emission rate required by the Final Rule cannot be maintained under all operating conditions, putting Rainbow at risk of being unable to demonstrate compliance through the newly required use of PM

CEMS. Third, in accordance with EPA's Section 111(d) Guidelines, Rainbow is working to install full-scale post-combustion carbon capture and sequestration system ("CCS"), which will result in the near elimination of fPM emissions from Coal Creek Station—rendering the Final Rule unnecessarily costly and duplicative. In sum, this Final Rule, if not stayed, will have damaging and irreparable impacts on Rainbows operations, as described below.

3. This declaration is based on my personal knowledge of facts and on analyses conducted by my staff.

4. I am submitting this declaration because the Final Rule imposes immediate harm to Rainbow and its operations.

BACKGROUND ON RAINBOW'S OPERATIONS

5. Rainbow is a wholesale power generation company headquartered in Bismarck, North Dakota. Rainbow has owned and operated Coal Creek Station since May 1, 2022.

6. Coal Creek Station has been generating and distributing energy in North Dakota and the upper Midwest region of the United States since 1979. Coal Creek Station produces up to 1,151 megawatts of electricity per hour by combusting over seven million tons of beneficiated lignite (coal originally purchased from Falkirk Mining Company which then gets beneficiated in-house with a patented

pollution control technology, "DryFining™," further described below). It directly employs over 200 people at its facility near Underwood, North Dakota.

7. Since it began its commercial operation in 1979, Coal Creek Station has continuously improved its methods for controlling air pollution. Coal Creek Station stands out from other coal-fired power plants to the point that it has been acknowledged by the federal government multiple times for its environmental stewardship.[1]

8. As just one example, the Department of Energy selected Coal Creek Station to participate in a government-industry partnership, where Coal Creek Station "will help U.S. coal-fired electricity generating plants to meet both existing environmental objectives as well as those emerging in the near future."[2] The resultant multi-pollutant control technology, "DryFining™," improves the heating value of the coal while removing constituents that cause harmful pollution, mainly nitrogen oxide (NOx) and sulfur dioxide (SO_2). This technology is the first of its kind and remains a pioneering technology in the industry.

[1] *See, e.g.*, 76 Fed. Reg. 58,570, 58,584 (Sept. 21, 2011) (discussing Coal Creek Station's involvement in the Clean Coal Power Initiative).

[2] National Energy Technology Laboratory, Topical Report No. 27, at 4 (June 2012) (provided as Attachment A to this Declaration).

IMPACT OF THE FINAL RULE ON RAINBOW

9. The Final Rule, under Section 112 of the Clean Air Act, revises the national emission standards for hazardous air pollutants for coal- and oil-fired electric utility system generating units. Such a category of units would include Coal Creek Station.

10. Among other changes, the Final Rule reduces the emission limit for Hg, reduces the emission limit for fPM, and requires the use of PM CEMS to demonstrate compliance with the fPM standard. Under the Final Rule, Rainbow will have to install Hg controls, and it will also have to install PM CEMS. Given its lack of experience with using PM CEMS and uncertainty as to whether it could comply with the fPM standard using this measurement system, Rainbow may also install fPM controls.

11. Because the Final Rule imposes a short compliance timeline, Rainbow cannot delay action during the pendency of litigation, and it must begin implementing the required controls and monitoring system immediately.

12. To comply with the new Hg emission limit, Rainbow will need to install new controls, specifically an activated carbon injection ("ACI") system.

13. Rainbow will need to install an ACI system, with the capital cost of the ACI system costing around $5 million.

14. Rainbow estimates the activated carbon product alone will cost approximately $145 *per hour per unit* to meet the Hg emission limit, which equates to $2.4 million per year in total for both units. This is on top of the capital expense and the operations and maintenance costs.

15. In addition, Rainbow will have to install PM CEMS to demonstrate compliance with the fPM emission limits.

16. Prior to the Final Rule, Rainbow demonstrated the emissions from both units at Coal Creek were less than half of the existing rule's limit of 0.03 lb/mmBtu and qualified the units as Low Emitting EGUs ("LEE") for fPM as defined in the rule, by demonstrating fPM emission rates of less than 0.015 lb/mmBtu over the course of 12 consecutive quarterly emissions tests. Thus, ongoing LEE qualification tests were only required every three years and have been successfully completed in 2021 and 2024. This emissions testing is completed using EPA approved methods and directly measure actual fPM in the flue gas.

17. By contrast, PM CEMS provides continuous monitoring of a parameter calculated based on a correlation developed during its certification rather than direct measurement of the fPM.

18. The results from the currently required fPM stack testing at Coal Creek Station have demonstrated that fPM emissions could reach the Final Rule's emissions limit, but it is not technologically sound to assume that Coal Creek could

maintain the emissions limit on a continuous basis with a reasonable margin of compliance. fPM emissions test results indicate variability in fPM emissions, based on numerous operational parameters which include fuel quality, load, coal drying operations and ash resistivity. The additional impact of adding ACI to the system has also not been evaluated and will result in increased fPM loading to the existing pollution control equipment.

19. By design, stack tests measure unit performance under a strict set of operating conditions—not during periods of startup, shutdown, malfunction, and the cycling driven by the high penetration of renewables within MISO. Coal Creek does not operate at a single, baseload level, or even at predictable levels, due to the amount and variability of renewable generation. Thus, testing performed under controlled conditions does not adequately reflect real world unit operation.

20. PM CEMS are a more expensive and less accurate method of measuring compliance with low emission rates. Unlike stack tests, which take a direct measurement of the flue gas to measure the actual amount of particulate matter it may contain, PM CEMS do not take direct measurements. Instead, they rely on measuring some other characteristic of the flue gas to estimate fPM based on changes in that characteristic, such as light scatter or beta attenuation. Also, the indirect nature of the PM CEMS necessitates a correlation test consisting of a minimum of 15 parallel stack test runs spanned across three different fPM levels to ensure the

readings of the CEMS are as closely correlated as possible to actual fPM emission rates measured via Method 5.[3] This recuring testing is necessary for the PM CEMS's periodic calibration and certification and will lead to increased fPM emissions to the CCS system, which will complicate CCS's removal of the fPM and result in premature fowling of the system.

21. Ultimately, the inaccuracy of the PM CEMS combined with the lower fPM emission limit presents a compound situation for Rainbow. The difficulty in demonstrating achievement of the new standard will be exacerbated by the requirement to use the less accurate PM CEMS, and the difficulty in using PM CEMS will be exacerbated by the dramatically lower standard. Serious concerns remain with respect to whether a PM CEMS can effectively estimate emission rates at such low levels, or whether emissions that low will be too small for a PM CEMS to differentiate compliance from a false reading. Ongoing quality assurance testing is needed to ensure the PM CEMS data is valid, which in turn increases the cost of PM CEMS. Initial quotes received indicate the necessary annual audit would cost $48,000 for both units, and the three-year audit would cost $175,000 for both units.

22. Rainbow estimates PM CEMS installation on each unit at Coal Creek Station would cost $345,000-$410,000. This includes $150,000 for the analyzer, $60,000-$100,000 for stack and electrical port upgrades, $35,000 for

[3] 40 C.F.R. Part 60 App. B, Performance Specification 11.

commissioning, and $100,000-$125,000 for initial certification. By contrast, because of its LEE qualification, Rainbow currently spends $3,000-4,000 per unit annually for fPM testing.

23. Given PM CEMS's inaccuracies and uncertainties, Rainbow may be unable to meet the fPM emissions limit using PM CEMS. As a result, Rainbow may have to install fPM controls at Coal Creek Station to comply with the Final Rule's compliance deadline of July 8, 2027, three years after the effective date of July 8, 2024.

24. All these fPM-related costs and expenditures are ultimately duplicative because Rainbow is actively working to install CCS at Coal Creek Station. CCS would virtually eliminate all fPM emissions from Coal Creek Station. fPM emissions correlate directly with amine degradation. Minimizing fPM emissions into the CCS system is needed for performance of the system. Rainbow completed a FEED study for the CCS and is currently undergoing a bridge study to determine what emission controls will be installed upstream of the CCS which will further reduce fPM and decrease amine degradation.

25. Although the highly effective fPM control of CCS is recognized by EPA's own Section 111(d) Guidelines, the Final Rule does not align the timeline for installation of fPM controls with that for implementation for CCS.[4]

26. Accordingly, under the timeline for compliance with the Final Rule, Rainbow will have to begin work and thus incurring unrecoverable costs immediately.

27. Investment costs for costly and duplicative emission control methods present unique challenges to Rainbow due to its status as a "merchant power producer" in the power market. Most power in the United States is provided by either investor-owned utilities or public utilities. Both utilities operate under a vertically integrated monopoly framework. Because of their vertically integrated monopoly structure, these utilities are also heavily regulated by the government to ensure that the interests of the consumers are preserved. Such regulatory measure includes rate-setting. State regulatory commissions set the rates at a level so that the regulated utility could cover its cost of service plus a reasonable "rate of return" (profit) on the capital the utility invested on its plants, whether that be the original construction or improvements to the facility.

[4] EPA, *Greenhouse Gas Mitigation Measures for Steam Generating Units Technical Support Document,* at 22, 59-60, available at: https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power.

28. In contrast to what has been discussed above, Rainbow (through Coal Creek Station) is a privately owned "merchant power producer." Rainbow is not an investor-owned utility, nor is it a public utility. Unlike the traditional structure of many utility companies, Rainbow does not have a vertically integrated monopoly system where it controls everything from electricity generation all the way to distribution of power to the end-use consumers who, often times, could not switch electricity providers. Instead, merchant power producers would sell all the generated power into the wholesale open market.

29. Accordingly, this means Rainbow has no "captive ratepayer." While investor-owned utilities and public utilities have a set customer base (similar to how normal household consumers cannot select/switch their utility company), Rainbow has none. Rainbow does not have a monopoly over its end-use consumers; the market (and its participants) could always favor a different electricity producer if Rainbow's power production costs are too high.

30. Second, unlike investor-owned utilities and public utilities which have a chartered right—guaranteed by the state government—to recover costs (usually through rate-setting orders as discussed above), Rainbow cannot recover any capital or operational costs from its end-use customers. Rainbow has no "rate base," i.e., the right to earn a specified rate of return backed by the state energy commission, and never will as a merchant power producer.

CONCLUSION

31. For the reasons described above, Rainbow is facing imminent and substantial harm from the Final Rule.

I, Stacy L. Tschider, declare under penalty of perjury that the foregoing is true and correct.

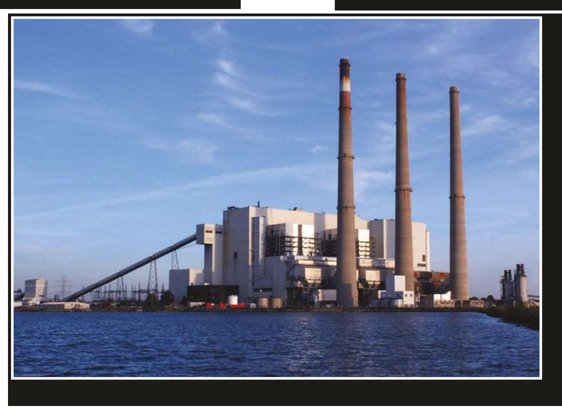
Executed on May 12, 2024

Stacy L. Tschider
Chief Executive Officer

ATTACHMENT A

TOPICAL REPORT NUMBER 27 JUNE 2012

CLEAN COAL TECHNOLOGY



Clean Coal Power Initiative Round 1 Demonstration Projects

Applying Advanced Technologies to Lower Emissions and Improve Efficiency

A report on three projects conducted under separate cooperative agreements between the U.S. Department of Energy and:

- Great River Energy
- NeuCo. , Inc.
- WeEnergies

Cover Photos:

- Top left: Great River Energy's Coal Creek Station
- Top right: We Energy's Presque Isle Power Plant
- Bottom: Dynegy's Baldwin Energy Complex

U.S. DEPARTMENT OF ENERGY

GREAT RIVER ENERGY®

A Touchstone Energy® Cooperative

NeuCo

The Optimization Standard™

we energies

CLEAN COAL TECHNOLOGY

Clean Coal Power Initiative Round 1 Demonstration Projects

Executive Summary

Coal is both plentiful and affordable in the United States (U.S.) and is expected to maintain its nearly 50 percent share of total electricity generation as demand increases. Our nation's energy security and environmental management depend on the resolution of environmental concerns associated with increased coal use. Cost-effective and efficient technologies developed to ensure the environmentally clean utilization of this resource have been designated as "clean coal technologies."

Clean coal technology research and development (R&D) began in the 1970s. Many promising technologies had emerged by the 1980s, but were not implemented at the commercial scale due to the financial and technical risks associated with the first commercial-scale installation. A pathway to facilitate the further development of these technologies was initiated by Congress and implemented by the U.S. Department of Energy (DOE) in 1985 with the creation of the Clean Coal Technology Demonstration Program (CCTDP). The CCTDP forged cost-sharing partnerships between DOE, non-federal public entities, technology suppliers, and clean coal technology stakeholders to reduce the financial and technical risks preventing their commercial-scale implementation and demonstration.

Building on the successes of CCTDP, DOE implemented the Power Plant Improvement Initiative (PPII) in 2001 to focus on enhancing the reliability of the nation's power grid. PPII was followed by the Clean Coal Power Initiative (CCPI) in 2002.

The CCPI is an industry/government cost-shared partnership program that furthers efficient clean coal technologies for use in new and existing U.S. electric power generating facilities. CCPI is a technology demonstration program implemented through a series of solicitations (rounds) that target priority areas of interest to meet DOE's Roadmap goals. Technologies emerging from the program will help U.S. coal-fired electricity generating plants to meet both existing environmental objectives as well as those emerging in the near future. CCPI is planned and managed by the DOE Office of Fossil Energy (FE) and implemented by the National Energy Technology Laboratory (NETL).

CCPI Round 1 (CCPI-1) criteria for candidate projects was very broad in that the solicitation was open to "any technology advancement related to coal-based power generation that results in efficiency, environmental, and economic improvement compared to currently available state-of-the-art alternatives." CCPI Round 2 (CCPI-2) encouraged proposals to demonstrate advances in coal gasification systems, technologies that permit improved management of carbon emissions, and advancements that reduce mercury (Hg) and other power plant emissions. CCPI Round 3 (CCPI-3) required projects that could demonstrate the capture, recovery, and sequestration or beneficial use of carbon dioxide (CO_2) from coal-fired power plants.

Future CCPI rounds will build upon the successes of previous rounds, demonstrating advanced technologies that strengthen the nation's energy and economic security with minimal impacts to the environment and consumer.

This report describes three projects that have successfully demonstrated emissions and plant control system upgrades that support the CCPI-1 objective of ensuring that the U.S. has clean, reliable, and affordable electricity. The Baldwin Energy Complex project utilized an artificial intelligence (AI) system that increases the plant's thermal efficiency while reducing emissions. The Great River Energy (GRE) project increased boiler efficiency by reducing the fuel moisture content. The TOXECON™ project removed Hg from the flue gas stream without affecting the marketability of the fly ash.

The **Demonstration of Integrated Optimization Software at the Baldwin Energy Complex** project demonstrated the integration of advanced, on-line, combustion/emission control optimization software. The demonstration showed that an integrated process optimization approach can increase the thermal efficiency and reliability of the plant, with the concurrent benefit of a corresponding reduction of airborne emissions such as nitrogen oxides (NO_X), CO_2, and particulates.

The Cooperative Agreement for the project at the Baldwin Energy Complex was awarded on February 18, 2004. The project duration was 45 months and was completed on November 17, 2007. The project cost was $19,094,733 with a DOE share of $8,592,630 (45 percent). Project goals were met with the exception of the heat rate improvement target. However, it is believed that the heat rate goal could have been met had plant personnel not placed a higher priority on cyclone flame stability and NO_X reduction. To date, the participant has reported well over 50 sales of its optimization modules.

In GRE's **Increasing Power Plant Efficiency: Lignite Fuel Enhancement** project, waste heat from a power plant was used to lower the moisture content of the lignite fuel it consumes. Reducing the moisture content of the lignite increases the energy efficiency of the boiler, which means less fuel is required for a given load. Emissions reductions were achieved as a result of increased fuel quality, segregation of iron sulfide (pyrite) and mercury in the drying process, and increased oxidation of mercury resulting in greater mercury removal in the flue gas desulfurization (FGD) system.

A Cooperative Agreement for the Lignite Fuel Enhancement project was awarded on July 9, 2004. The project duration was 69 months with an operations completion date of March 2010. The estimated project costs were $31,512,215 with a DOE share of $13,518,737 (43 percent). The moisture content of the coal was reduced by the target amount of 8.5 percent, which resulted in a higher heating value (HHV) improvement from 6290 British thermal units/pound (Btu/lb) to 7043 Btu/lb. Also, the moisture removal process and the resulting increased fuel quality resulted in mercury (Hg) emissions being reduced by 41 percent, with NO_x and sulfur dioxide (SO_2) reduced by 32 and 54 percent, respectively. GRE has reported that 120 organizations have signed the necessary secrecy agreements to obtain detailed information on the technology. Some studies have been carried out to evaluate the technology for specific applications.

The **TOXECON™ Retrofit for Mercury and Multi-Pollutant Control on Three 90 MW Coal-Fired Boilers** project (TOXECON™) was an integrated Hg, particulate matter, SO_2, and NO_x emissions control demonstration program for application on coal-fired power generation systems. The TOXECON™ process utilized sorbents that were injected into a pulse-jet baghouse to control emissions. The technology was configured to not affect fly ash quality and its potential to be sold for constructive use. **TOXECON™** has been installed at seven plants in addition to Presque Isle Power Plant (PIPP) and robust sales of the Hg Continuous Emissions Monitor (CEM) have been reported. The recently released new Hg standard is expected to provide additional impetus for future application.

The total project cost was $47,512,830, with DOE providing $23,756,415 (50 percent). The demonstration began operation in January 2006, and was completed in September 2009. The project achieved the emissions reduction goals of 90 percent for Hg and 70 percent for SO_2 individually; however, the concurrent reduction of these emissions through an integrated treatment process was not consistently achieved. All remaining project goals, except for NO_x reduction, were met.

Clean Coal Technology Demonstration Program (CCTDP)

According to the Energy Information Administration's Annual Energy Outlook 2011, the demand for electricity in the United States is projected to increase by 25 percent by the year 2035. Because coal is both plentiful and affordable, the generation of electricity from this abundant resource is expected to continue to account for nearly 50 percent share of total generation. The nation's energy and economic security and environmental quality depend on the resolution of environmental concerns associated with increased coal use. These concerns can be addressed through the development of technology-based solutions that ensure environmentally clean energy utilization. These solutions must be both cost-effective and efficient to support economic growth. This new generation of technologies has been designated as "clean coal technologies."

The R&D of clean coal technologies began in the 1970s, with many promising technologies having emerged by the 1980s. The technologies were, however, unproven in a commercial setting and not implemented due to financial and technical risks. A pathway was needed to prove their technical performance and cost competitiveness in a commercial setting in order to facilitate their acceptance and reduce the risk of implementation. This pathway was initiated by Congress and implemented by the DOE beginning in 1985 with the creation of the Clean Coal Technology Demonstration Program (CCTDP). The CCTDP forged cost-sharing partnerships among the DOE, non-federal public entities, technology suppliers, and other clean coal technology stakeholders to reduce the financial and technical risks preventing the demonstration and commercialization of these technologies. As a condition of participation, CCTDP demonstrations were required to be at a scale and in an operational environment sufficient to determine their potential for satisfying marketplace technical, economic, and environmental needs.

Building on the successes of CCTDP, DOE implemented the Power Plant Improvement Initiative (PPII) in 2001, which called for technologies that could be rapidly implemented to enhance the reliability of the