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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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:

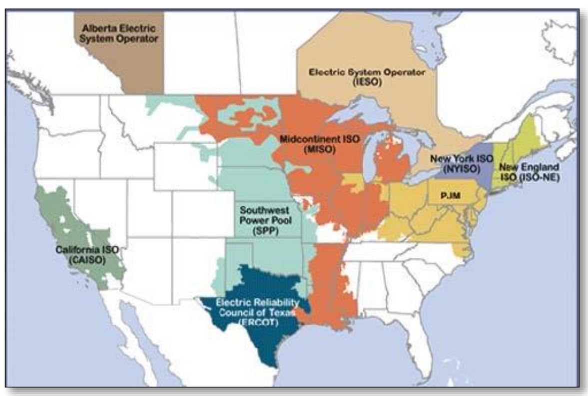
1. Granting or loaning money.
2. Issuing revenue bonds, with an upper limit of $800 million.
3. Entering into lease-sale contracts.
4. Owning, leasing, renting, and disposing of transmission facilities.
5. Entering contracts for the construction, maintenance, and operation of transmission facilities.
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:

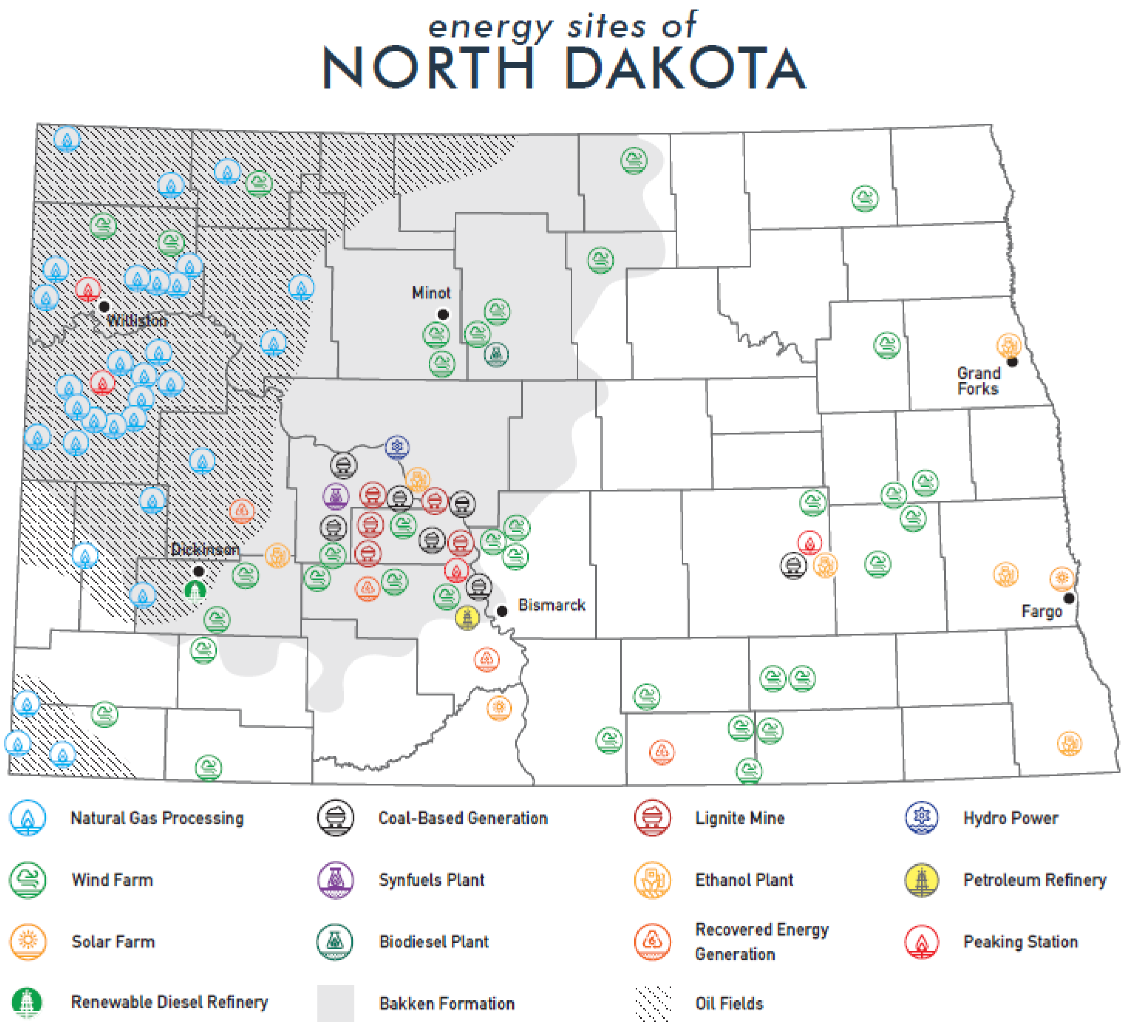
1. Renewable Generation:
    - Wind Generation: North Dakota has 4,250 MW of wind generation capacity in service, making it a significant contributor to the state's renewable energy portfolio. The average capacity factor for these generating facilities is 40% to 42%.
    - The 4,000 MW of wind generation 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 CO2 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.



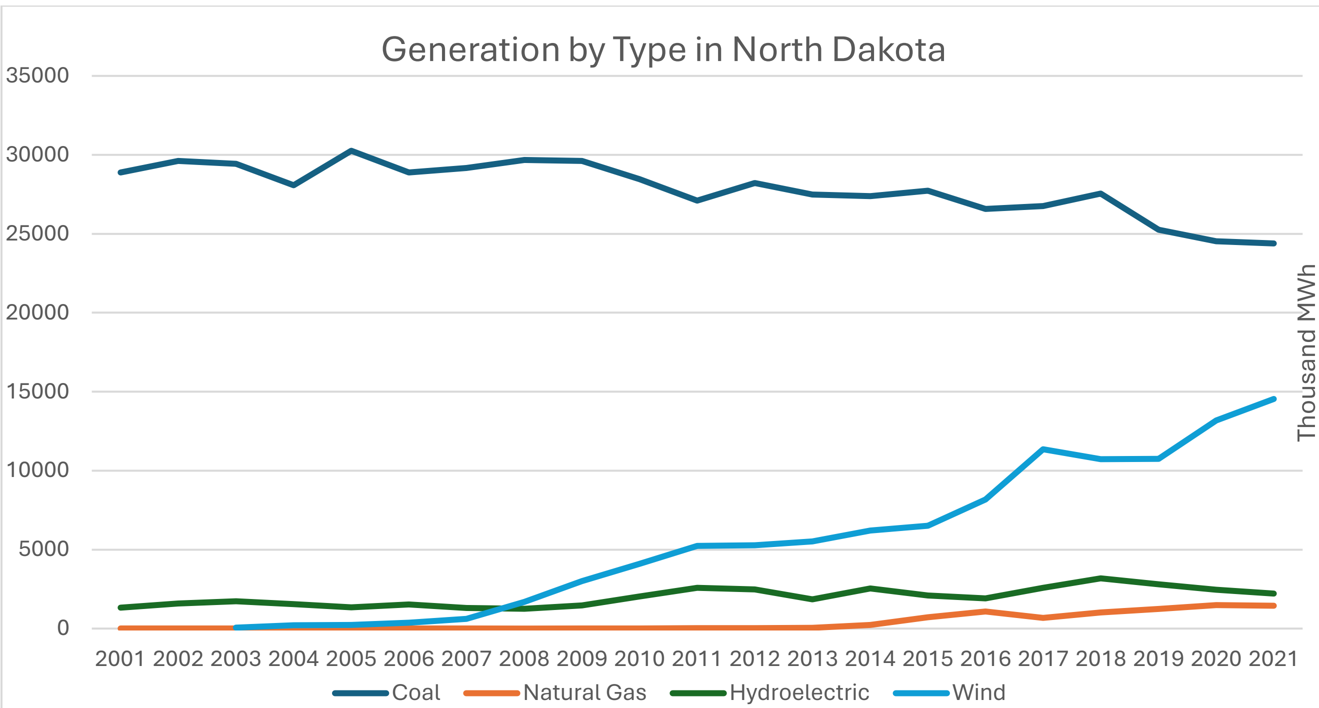
+ *Map courtesy of Bismarck State College National Energy Center of Excellence.*

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.

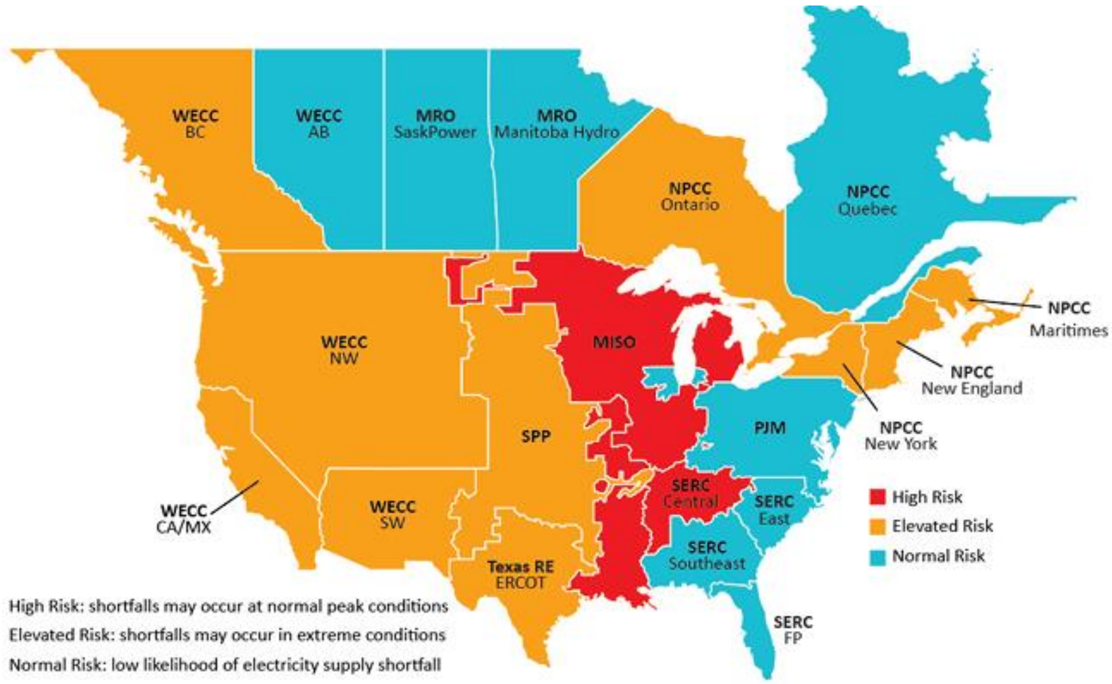


Figure 1: Risk Area Summary 2024–2028[8]

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

[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

[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

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[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

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[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.

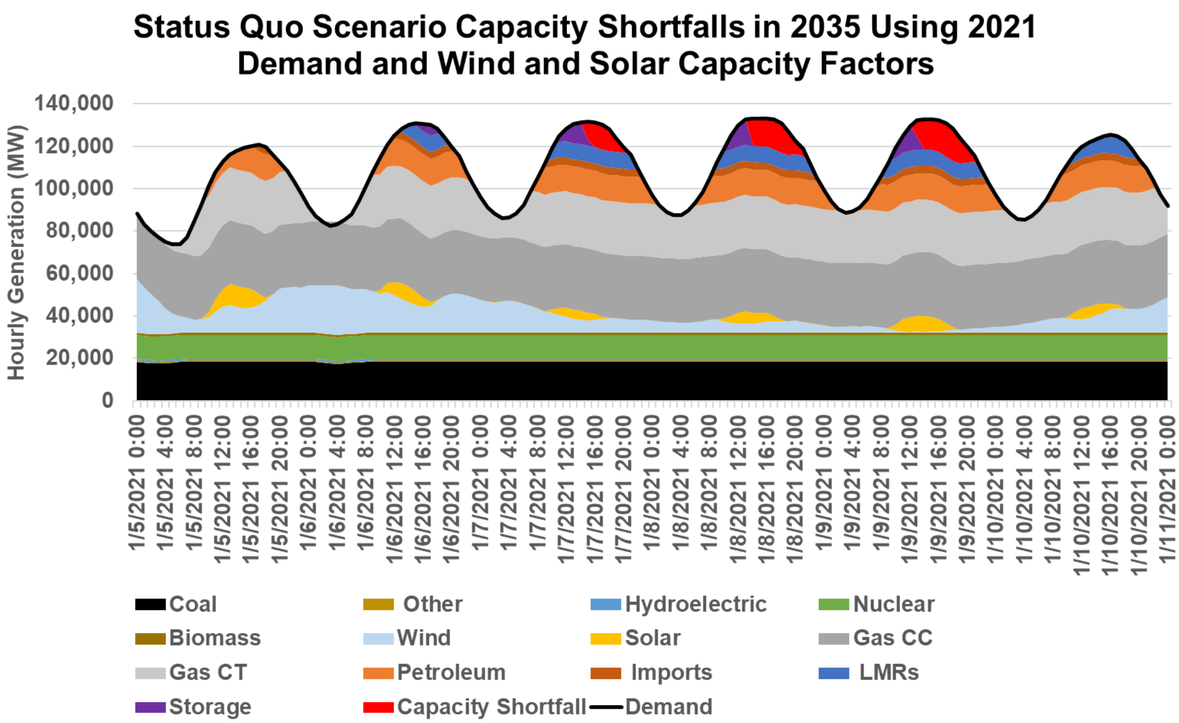

Figure D-1. This figure shows the generation of resources on the MISO grid in the Status Quo during a theoretical week in 2035. The purple portions of the graph show the battery storage discharging to provide electricity during periods of low wind and solar generation. Unfortunately, the battery storage 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.

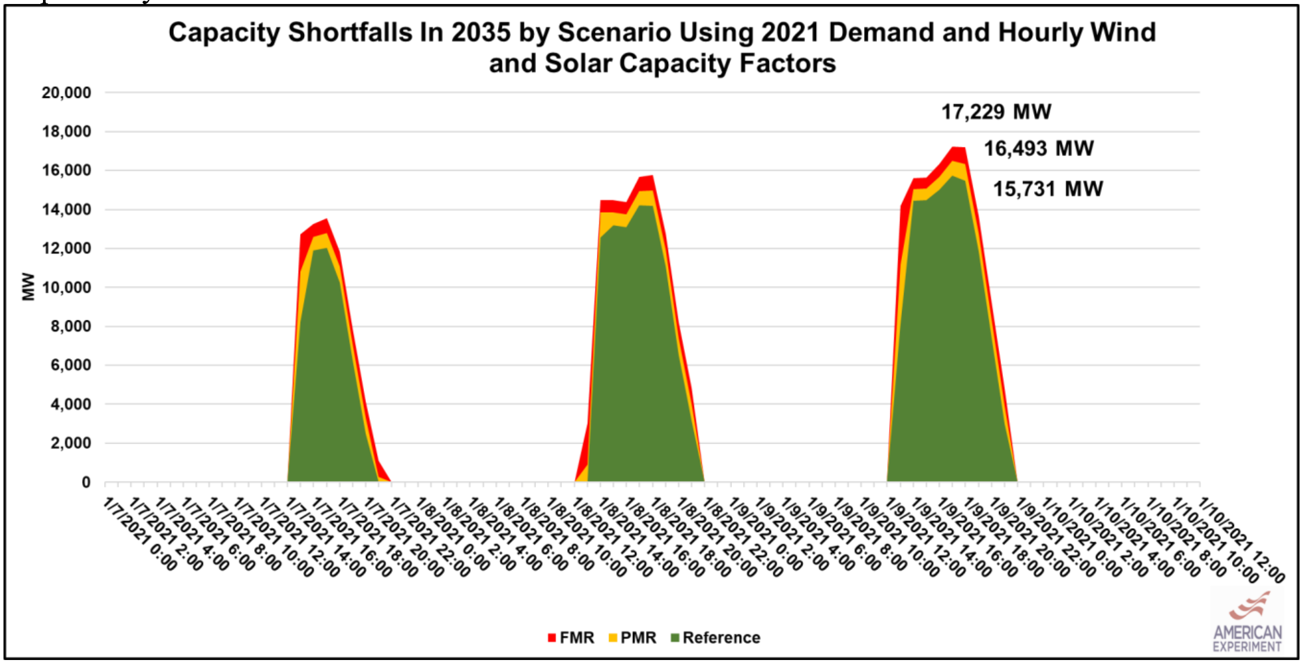

Figure D-2. Capacity shortfalls increase during a hypothetical January 9th, 2035 from 15,731 MW at their peak in the Status Quo to 16,493 MW in the Partial scenario and 17,229 MW in the Full scenario.

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]

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[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).

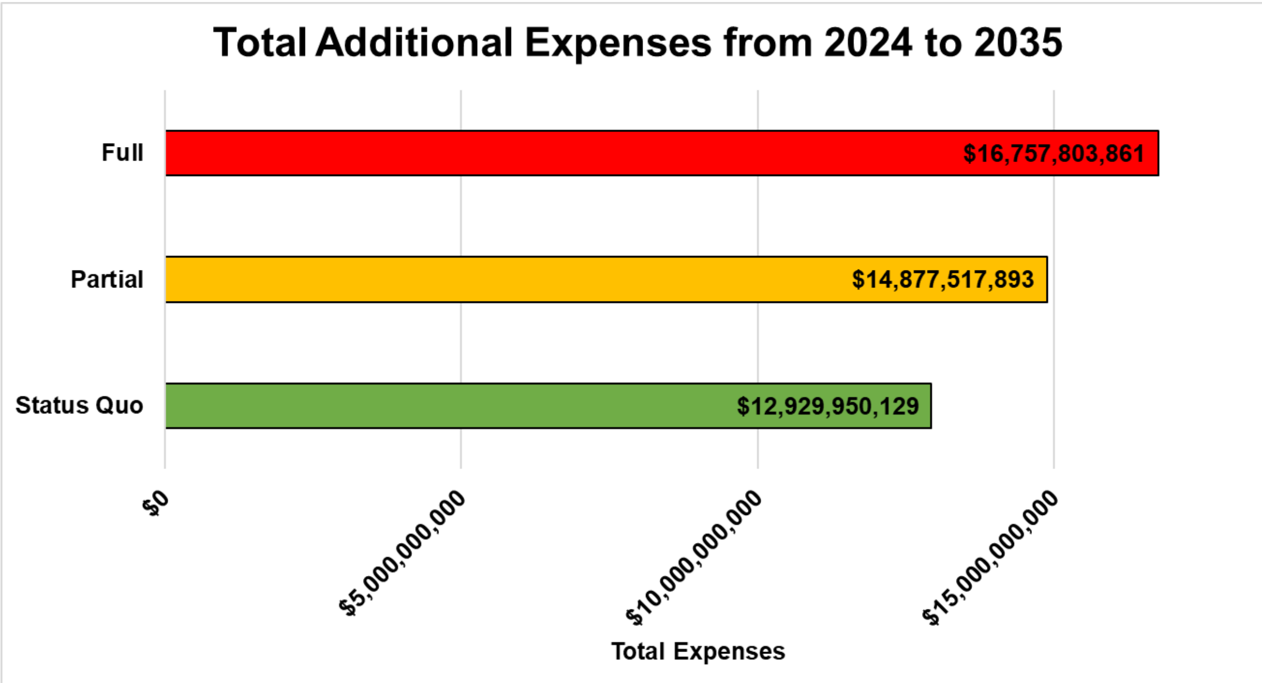

Figure D-3. The Partial scenario will cost $1.95 billion more than the Status Quo scenario from 2024 through 2035 and the Full scenario will cost $3.8 billion more than the Status Quo scenario in this timeframe.

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.

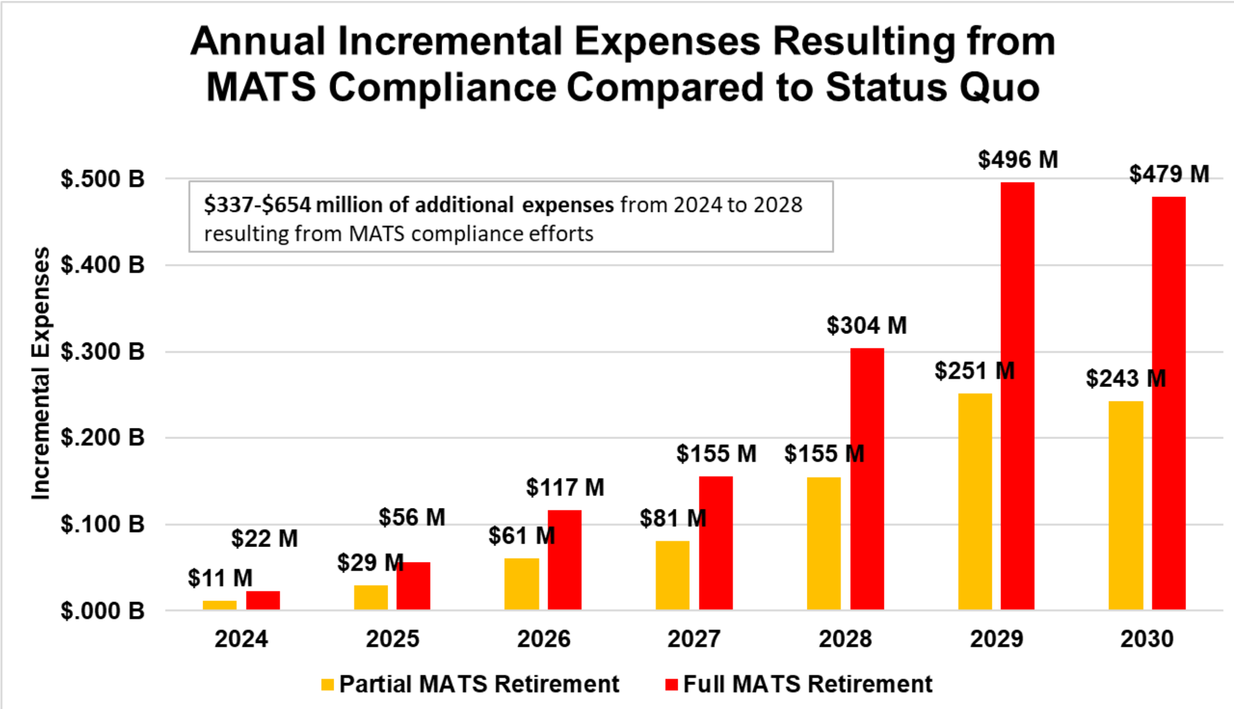

Figure D-4. This figure shows the annual cost of building the replacement capacity needed to maintain resource adequacy after the retirement of the lignite plants based on EPA's capacity accreditation values for wind, solar, storage, and thermal resources.

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).

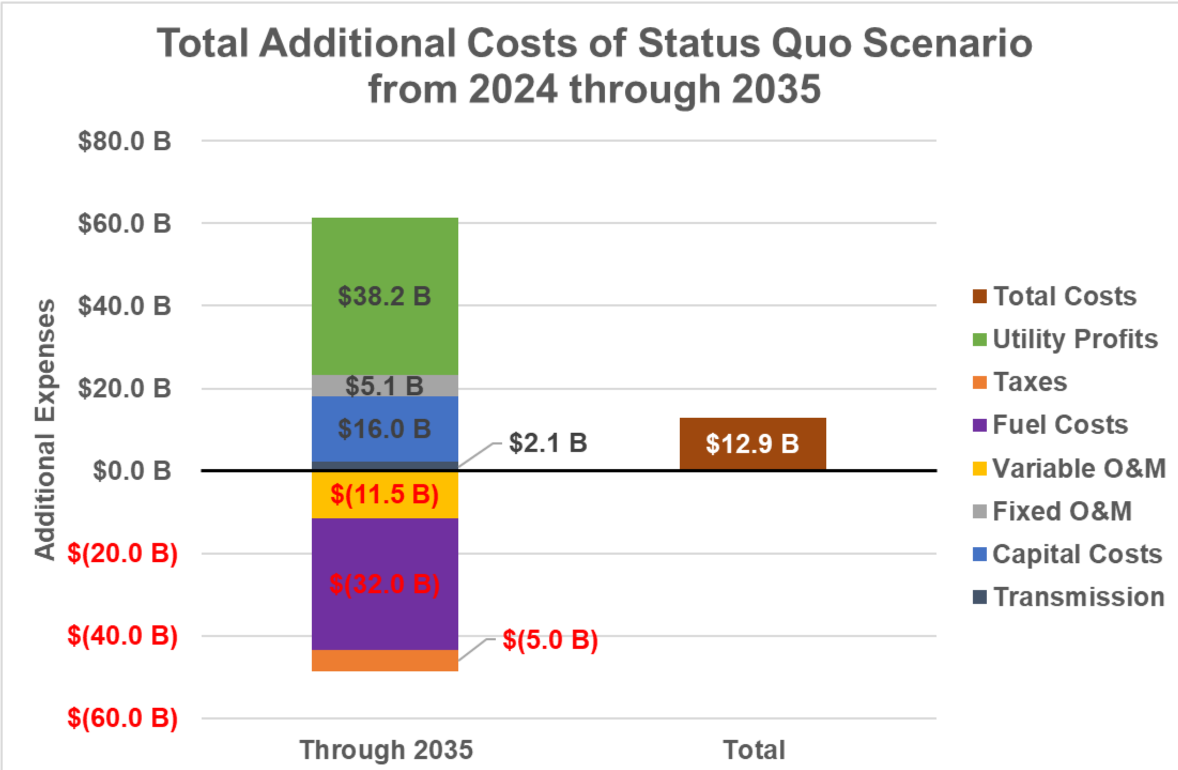

Figure D-5. The Status Quo scenario saves consumers money from lower fuel costs, fewer variable operations and maintenance costs, and lower taxes (due to federal subsidies) but these savings are outweighed by the additional costs. As a result, building the grid in the Status Quo scenario would increase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

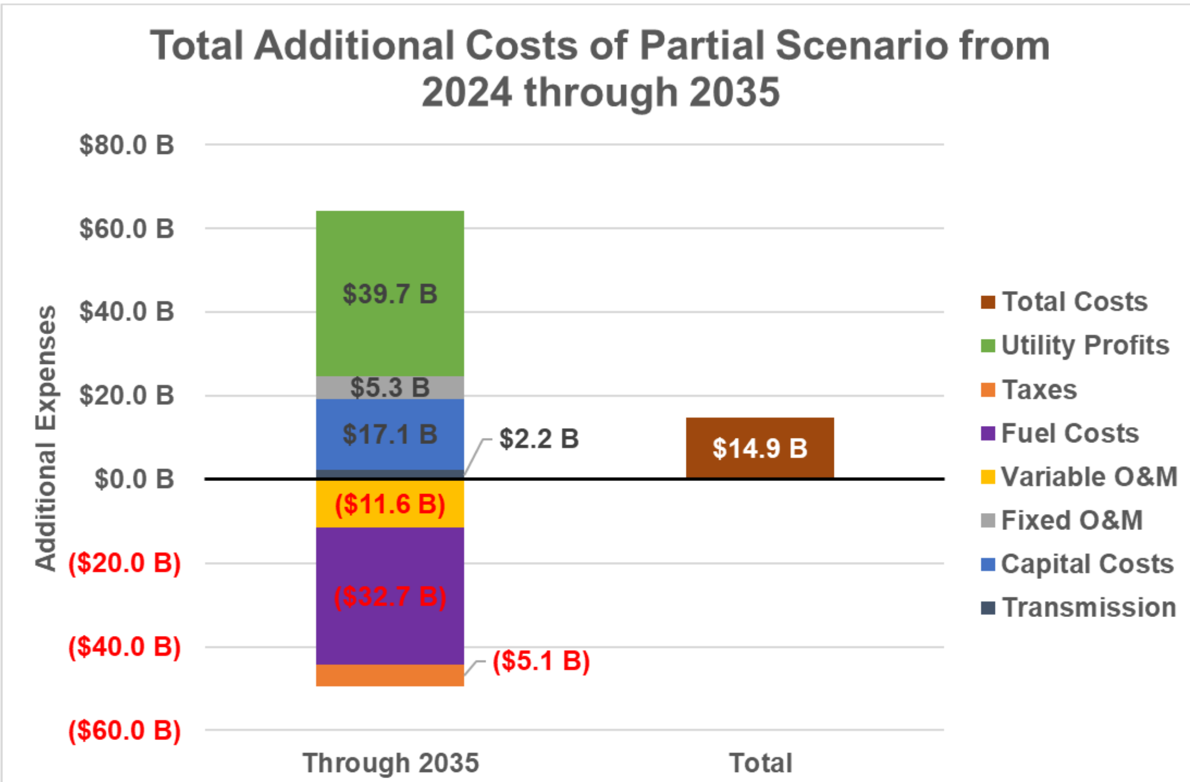

Figure D-6. The Partial scenario results in an $14.88 billion in additional costs compared to the current grid due to additional capital costs, fixed operations and maintenance costs, additional transmission costs, and additional utility profits.

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).

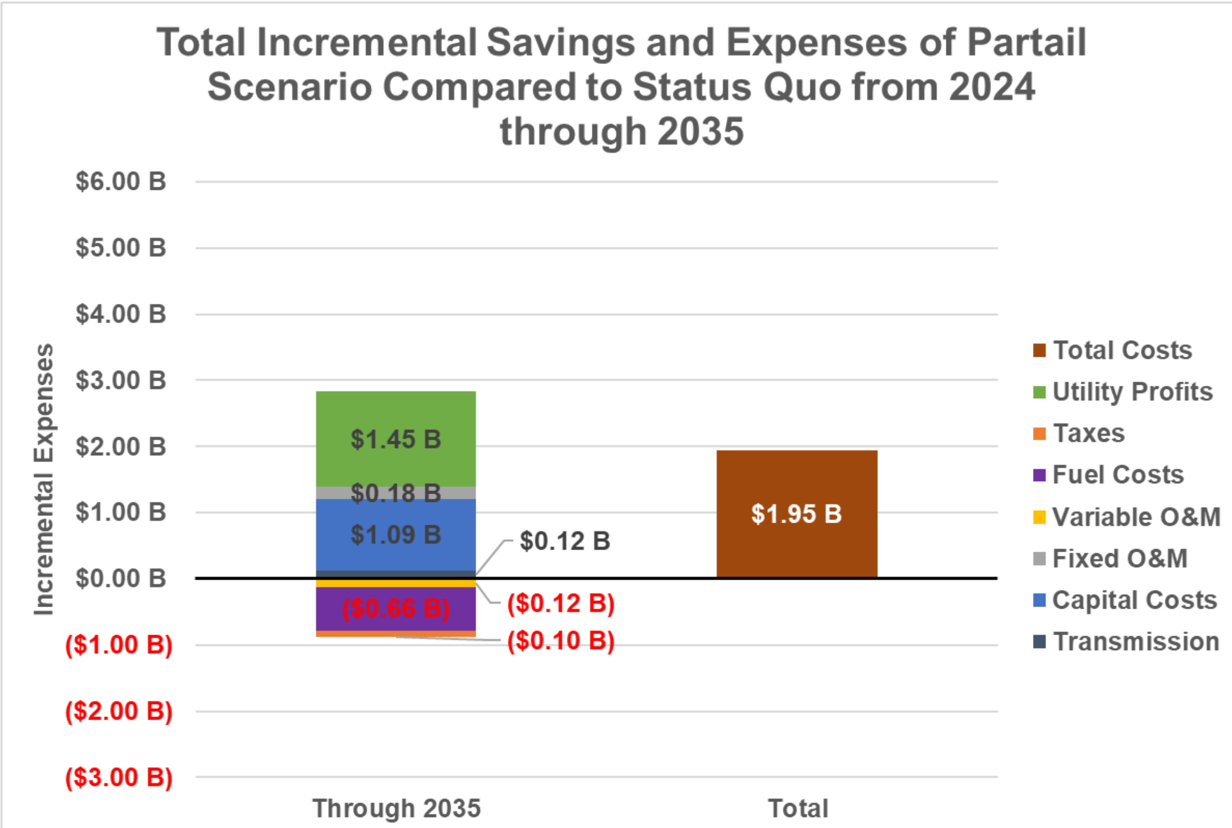

Figure D-7. The Partial scenario will cost MISO ratepayers an additional $1.9 billion from 2024 through 2035.

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).

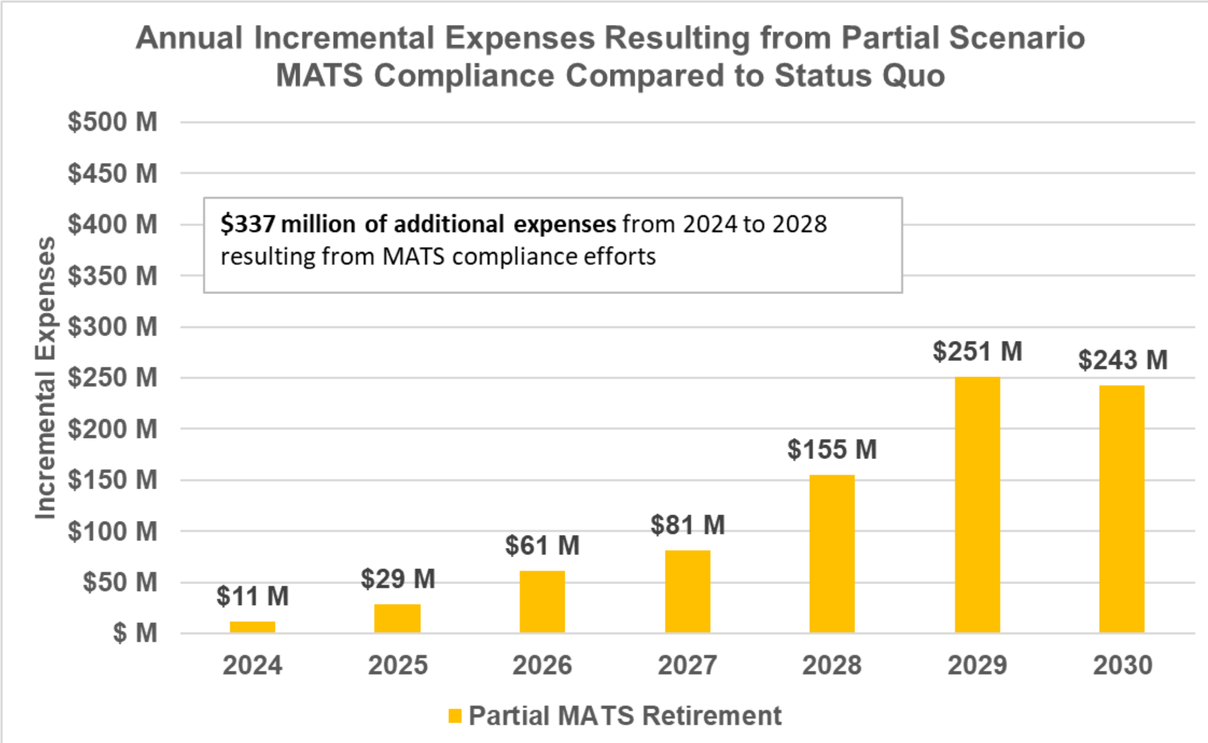

Figure D-8. This figure shows the annual incremental cost incurred by LSEs as a result of the lignite closures in the Partial scenario.

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).

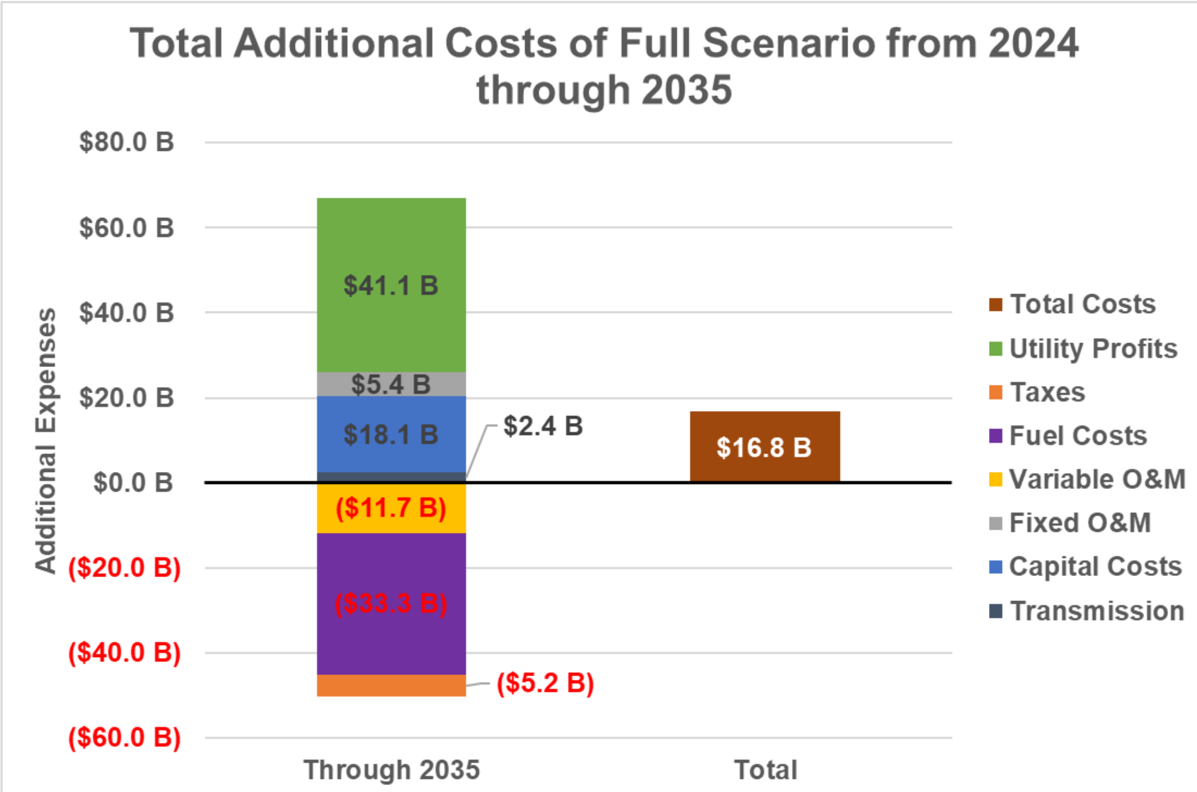

Figure D-9. The Full scenario results in an increase of $16.76 billion in costs compared to the current grid.

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).

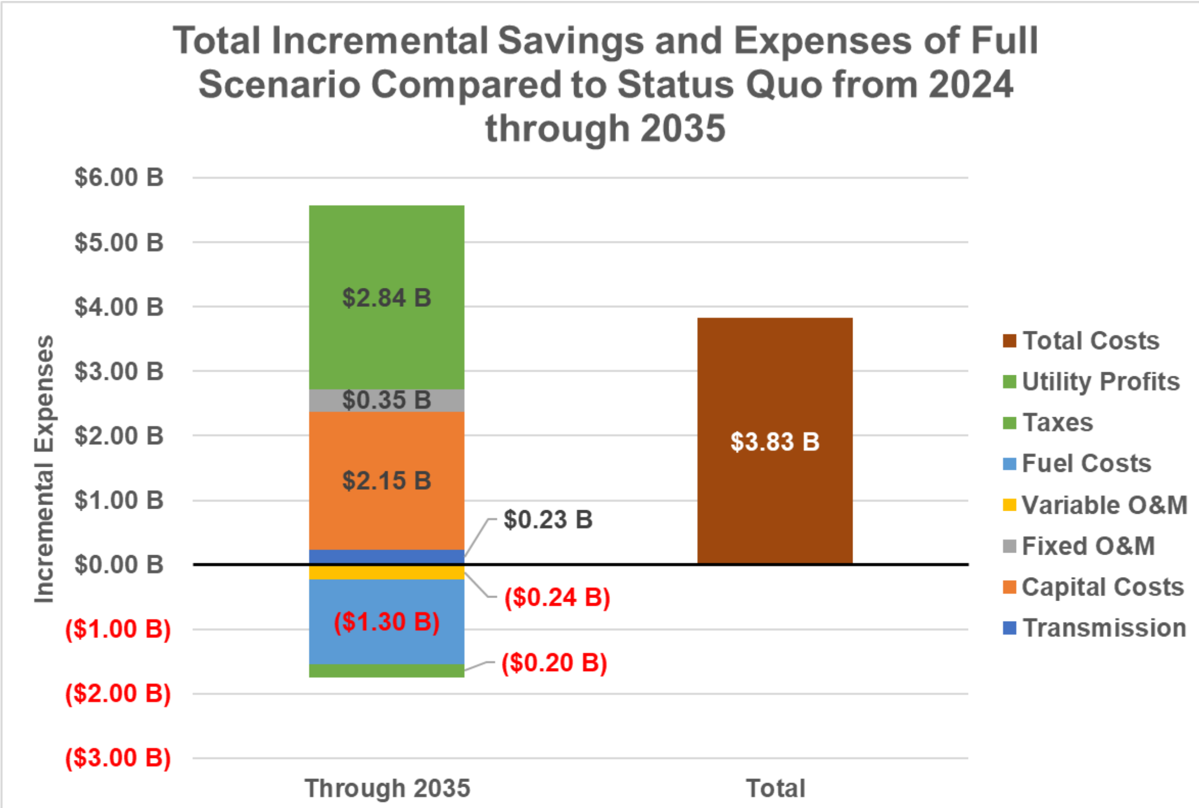

Figure D-10. This figure itemizes the expenses incurred in the Full scenario, which will cost an additional $3.8 billion compared to the Status Quo scenario.

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).

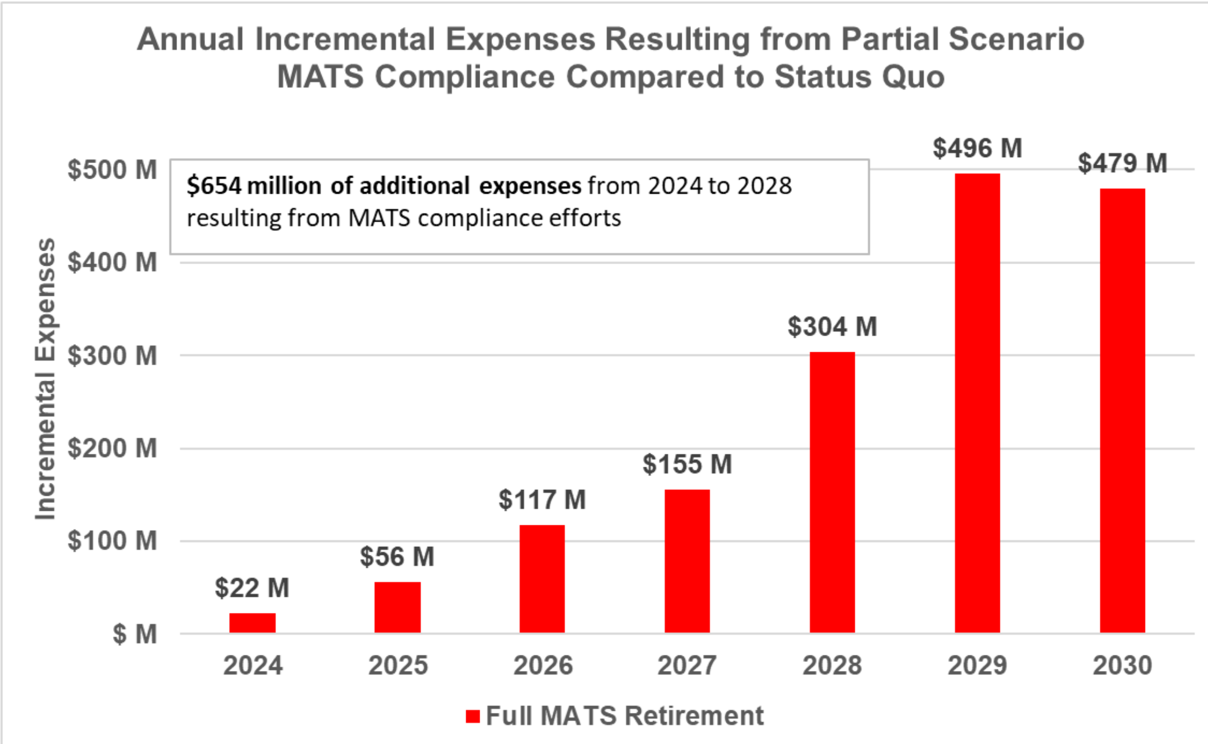

Figure D-11. LSEs would incur an additional $654 million in additional expenses, compared to the Status Quo scenario, as a result of the proposed MATS rules.

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]

[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.

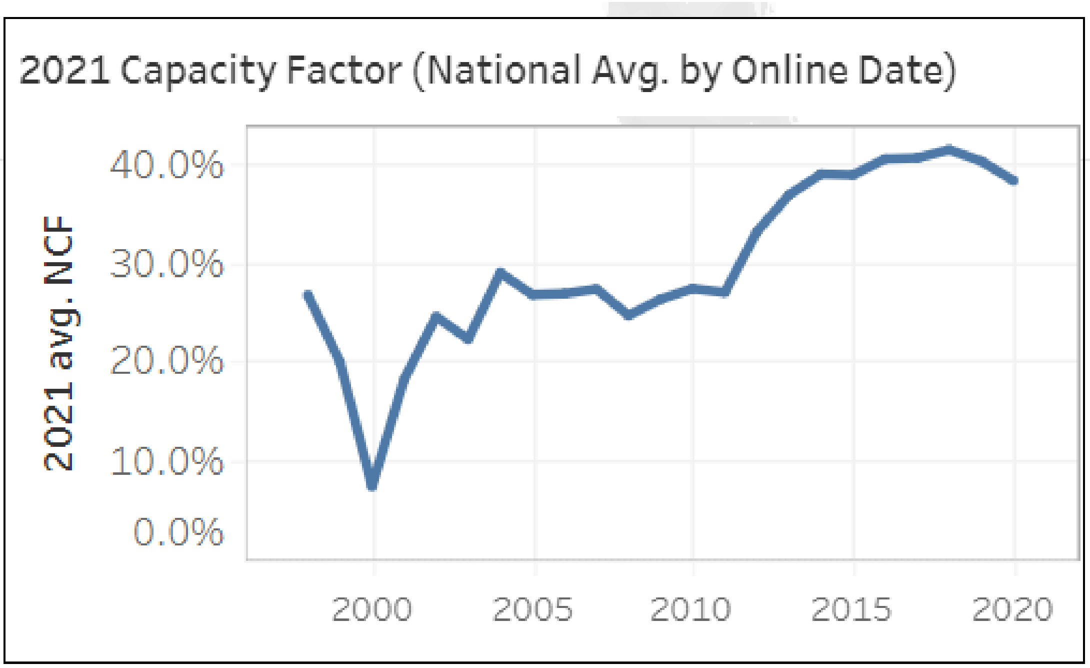

Figure D-12. This *figure shows capacity factors for U.S. onshore wind turbines by the year they entered service. In no year do these turbines reach EPA's assumed 42.2 percent capacity factor on an annual basis.*

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

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[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.

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[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

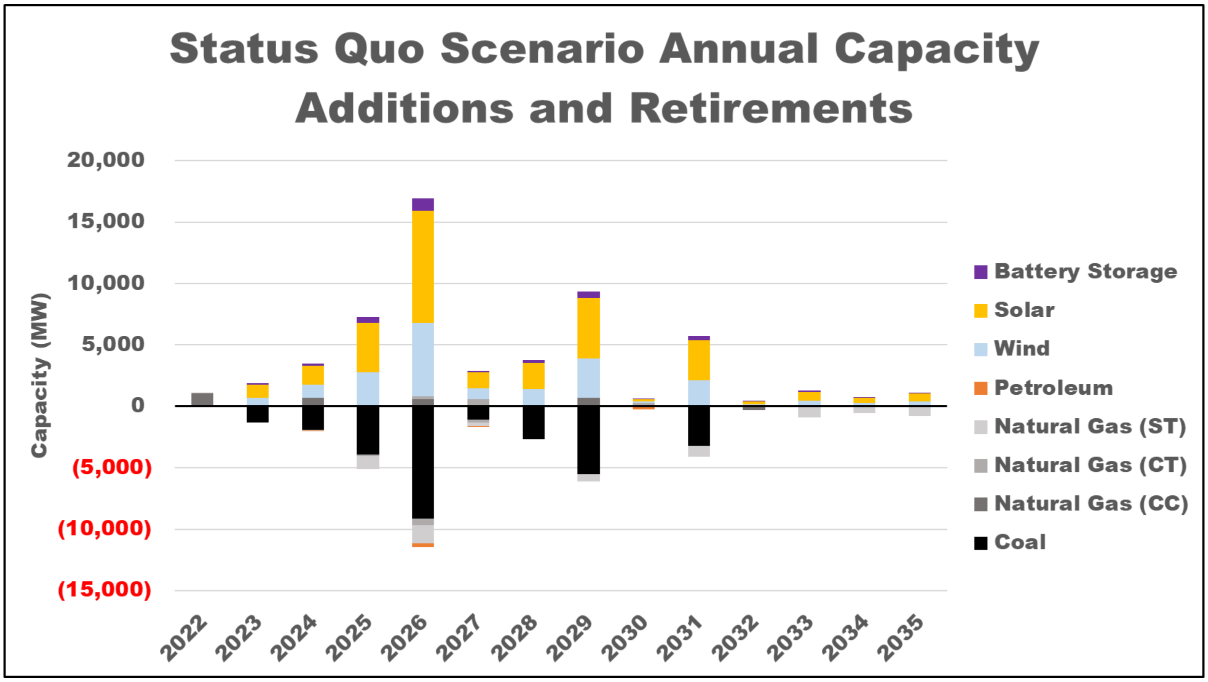


Figure D-13. This graph shows the annual capacity additions and subtractions needed to maintain resource adequacy using EPA's capacity accreditation metrics.

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.

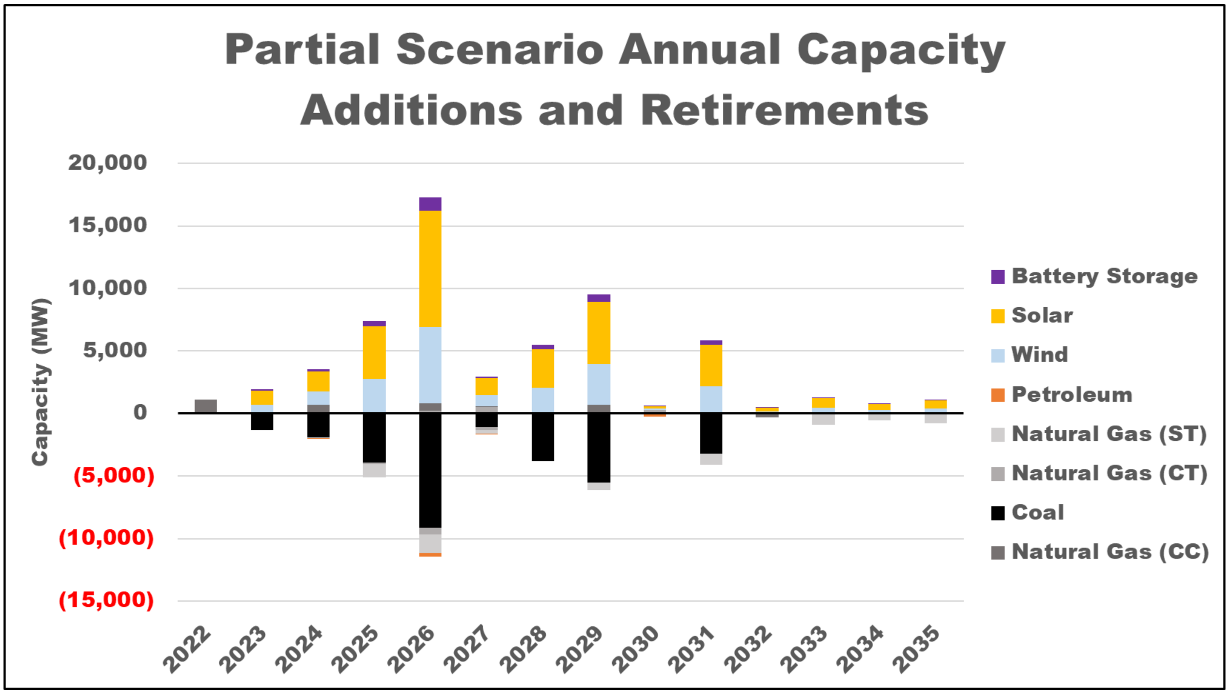


Figure D-14. This graph shows the annual capacity additions and subtractions needed to maintain resource adequacy using EPA's capacity accreditation metrics.

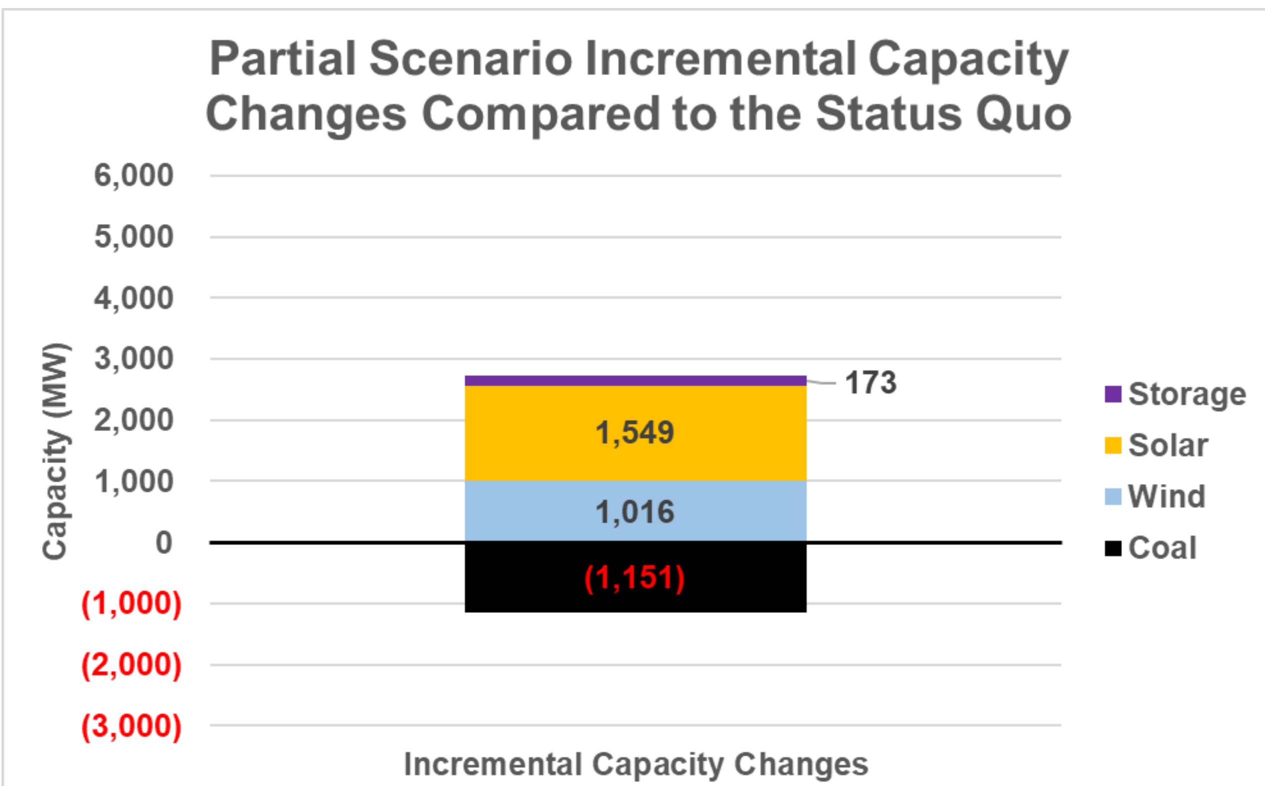


Figure D-15. This figure shows the incremental capacity retirements and additions in the MISO region under the Partial scenario.

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).

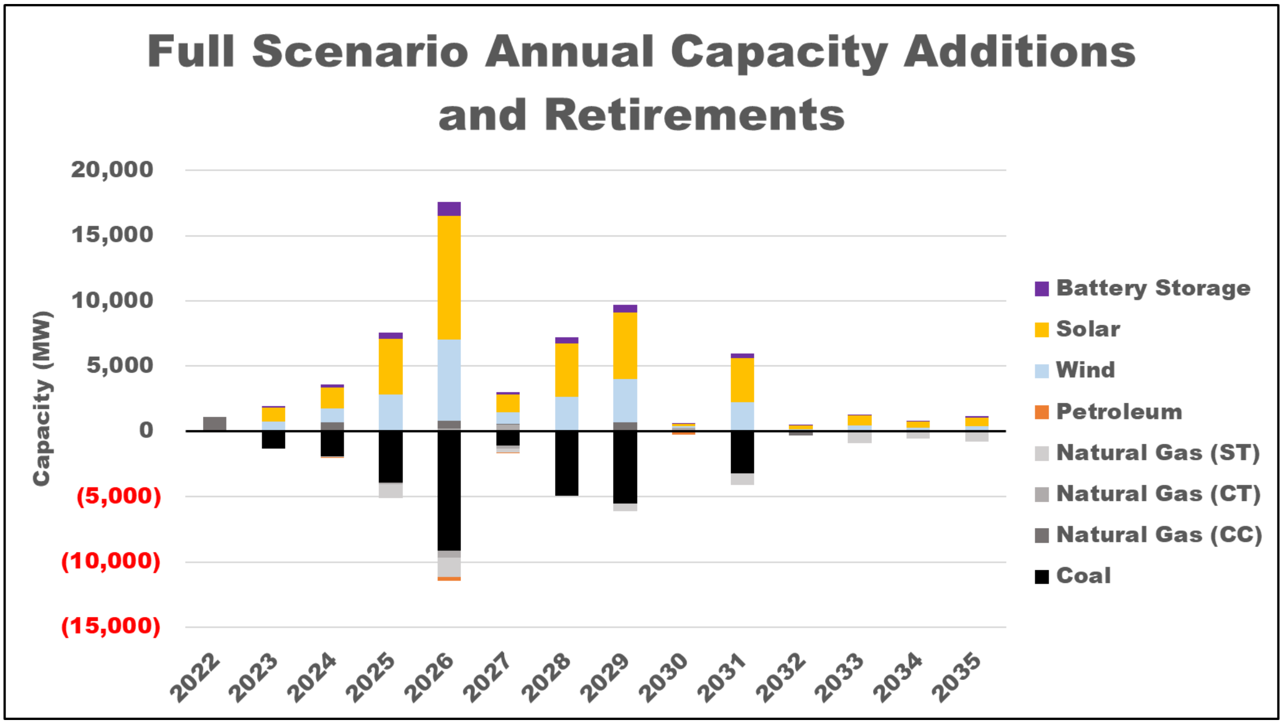


Figure D-16. This graph shows the annual capacity additions and subtractions needed to maintain resource adequacy using EPA's capacity accreditation metrics.

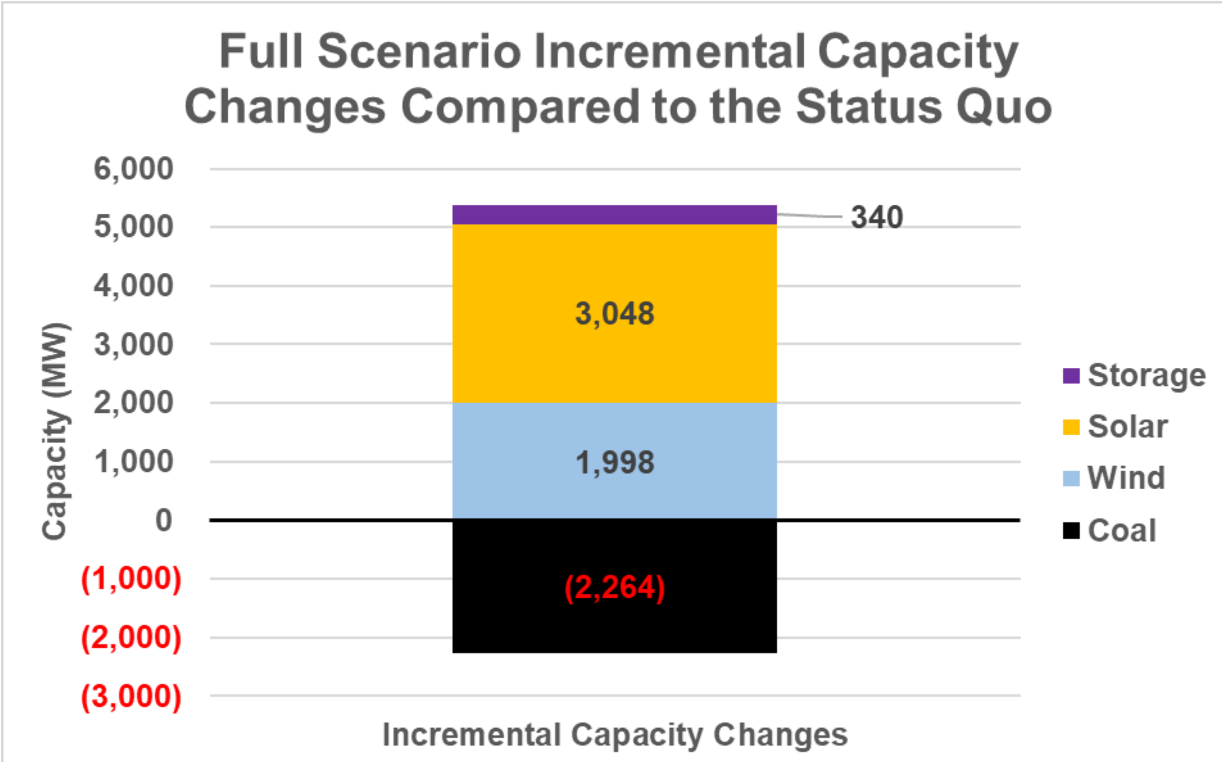


Figure D-17. This figure shows the incremental capacity closures and additions in the Full scenario.

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

Comparison:

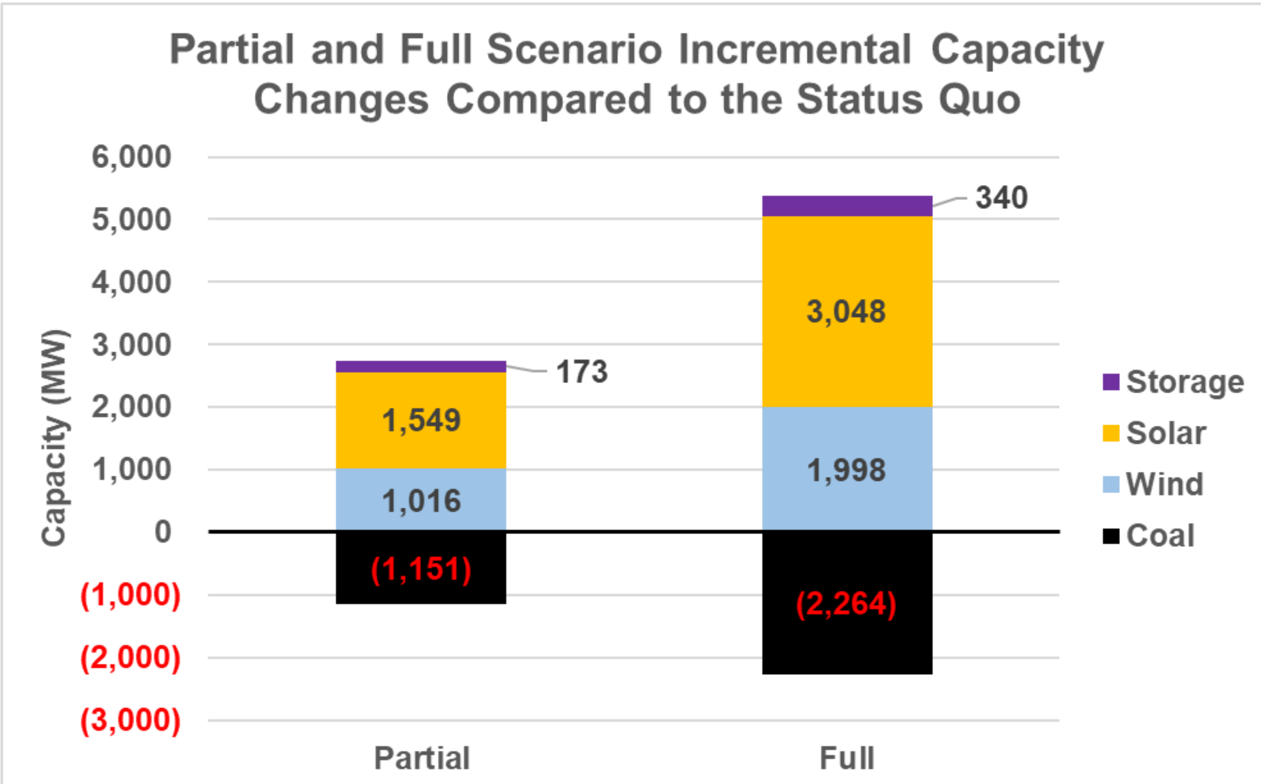


Figure D-18 comparison. This figure demonstrates the incremental retirements and additions in each scenario.

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

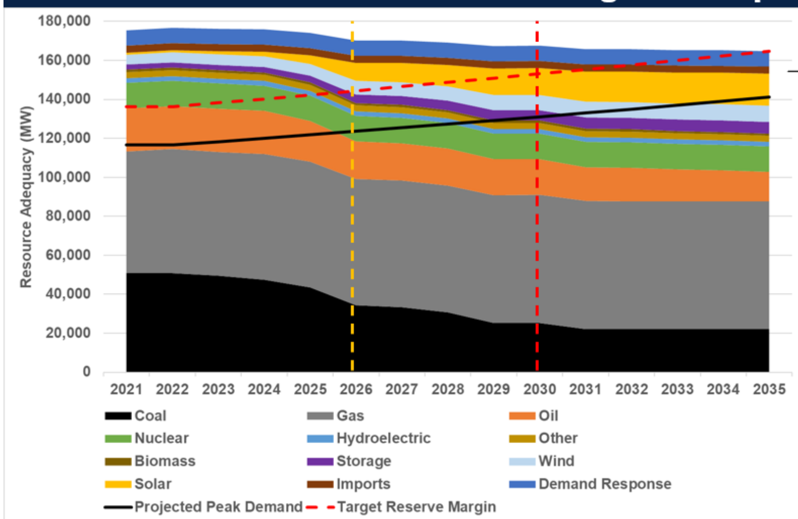
We performed a Resource Adequacy analysis on each of the three scenarios modeled to determine the potential impact to grid reliability in MISO region if implementation of the MATS Rule results in the forced retirement of lignite power plants.

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.

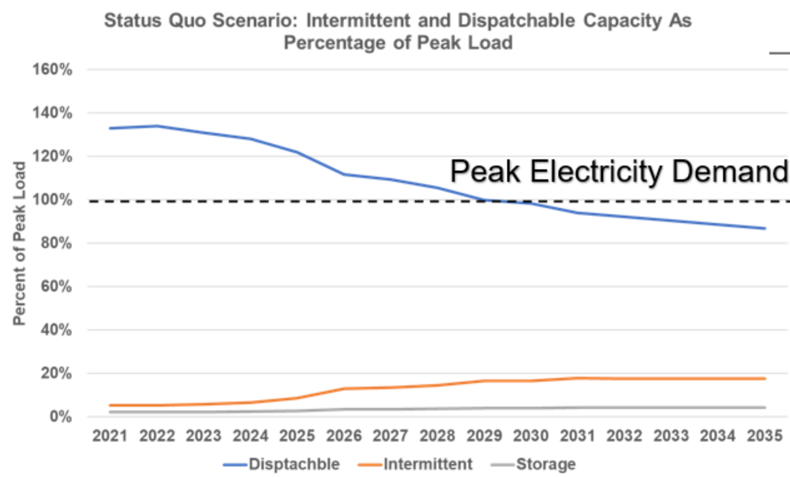
Beginning in 2026, MISO becomes reliant upon wind, solar, imports, or demand response (DR) to meet its target reserve margin, but the RTO still has enough dispatchable capacity to meet its projected peak demand. By 2030, the MISO region will rely on thermal resources and 4-hour battery storage to meet 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%

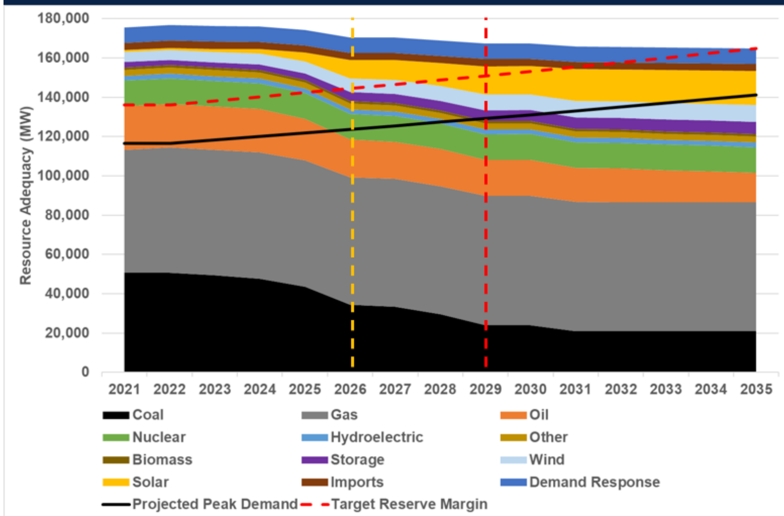
- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2029: Reserve margin depends on W/S/B*
- *2030 – 2035: Peak Demand depends on W/S/B*

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…



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.

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%

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

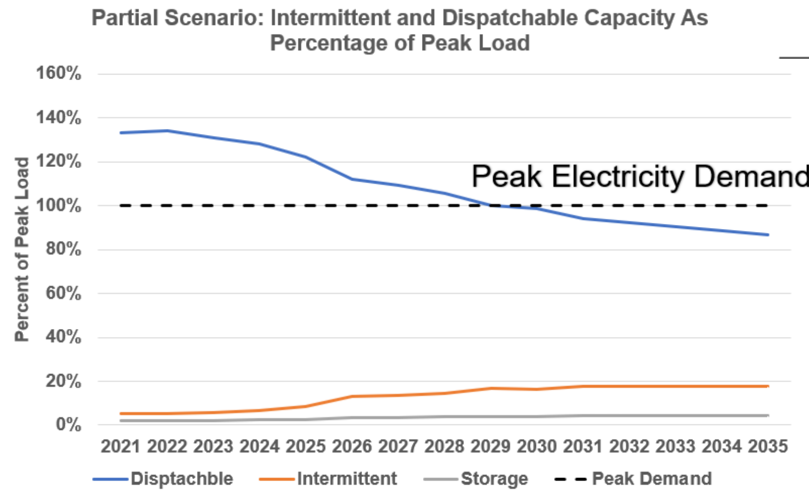
Figure D-21. By 2029, MISO will rely on wind, solar, and battery storage to meet its projected peak demand and target reserve margin.

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%).

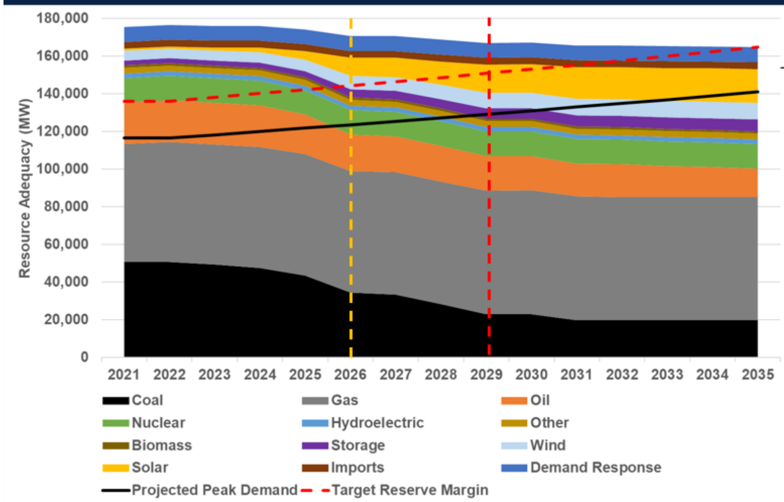
- *2023 – 2025: Adequate dispatchable capacity*
- *2026 – 2028: Reserve margin depends on W/S/B*
- *2029 – 2035: Peak Demand depends on W/S/B*

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*

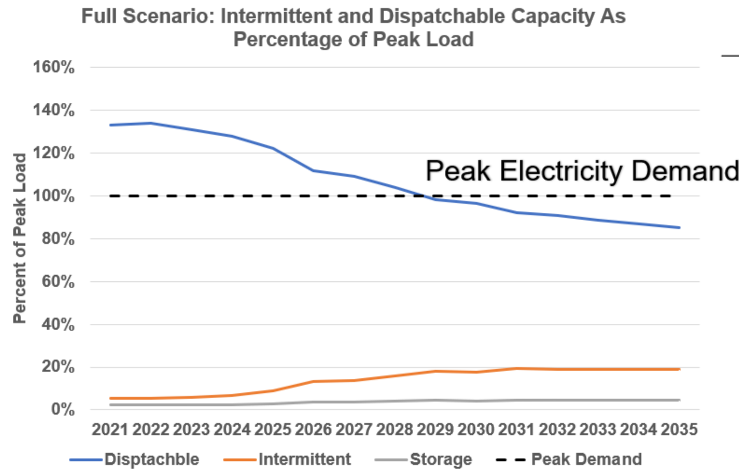
Figure D-23. The amount of dispatchable capacity available to meet projected peak demand in 2028 falls from 106 percent in the Status Quo scenario to 104 percent in the Full scenario, reflecting the closure of all the lignite capacity in MISO that year.

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.