Center of the American Experiment

Comments on

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 (Docket ID No. EPA–HQ–OAR–2023–0072; FRL–8536–02–OAR).

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Executive Summary

Center of the American Experiment, hereafter "American Experiment," has modeled the impact of the proposed Section 111 rules on the reliability and affordability of the electric grid in the subregions consisting of the Midcontinent Independent Systems Operator (MISO).

Our analysis determined that the Environmental Protection Agency's (EPA) proposed generation portfolio outlined in the Integrated Planning Model (IPM) output data for the MISO region has inadequate generating capacity to maintain grid reliability at all hours of the year based on historically observed hourly electricity demand curves and historical hourly wind and solar capacity factors, resulting in severe capacity shortfalls, i.e., rolling blackouts in MISO.[1]

American Experiment's modeling determined EPA's modeled generating portfolio in the Integrated Proposal with LNG Update scenario would be unable to serve load for 607 hours using historical hourly demand and wind and solar capacity factors observed in 2019, 2020, 2021, and 2022.[2] The 2021 data produced a devastating 26 GW capacity shortfall, i.e., rolling blackout, in January 2040, representing 19.5 percent of the demand at the time of the capacity shortfall, meaning one in five homes would be subjected to rolling power outages.

The blackouts observed in our modeling would be economically devastating. Using 2019 hourly electricity demand and wind and solar capacity factors would produce 274 hours of capacity shortfalls with an economic cost of $56.7 billion based on the Value of Lost Load (VoLL) criteria, which can be thought of as the Social Cost of Blackouts.[3]

Averting these blackouts will require a significant increase in installed generating capacity that greatly increases the cost of compliance with EPA's proposed rules. Our analysis determined building and operating this incremental capacity would cost ratepayers an additional $246 billion through 2055, or roughly $7.7 billion per year. An additional $93 billion would be borne by taxpayers in the form of federal subsidies, largely for wind and solar developments.

EPA's missteps regarding resource adequacy, reliability, and cost are threefold. One, it assumes that the Post-IRA Base Case maintains resource adequacy and reliability; two, it does not conduct a reliability analysis of its modeled resource portfolio in the MISO region; and three, it uses unrealistic thermal capacity accreditation ratings of 100 percent and uses overly generous accreditation assumptions for wind and solar. As a result, EPA is overestimating both resource adequacy and the reliability of the electric grid in the future under this regulatory regime and severely underestimating the cost of compliance with the new Section 111 rules.

These flaws are fatal. EPA is proposing rules that will fundamentally transform the entire U.S. electric grid, which is the most critical infrastructure in the nation, while conducting resource adequacy and reliability analyses that are less rigorous than a state-level Integrated Resource Plan (IRP) proceeding.

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[1] U.S. Environmental Protection Agency

[2] Hourly demand data and wind and solar generation were obtained from the U.S. Energy Information Administration's Hourly Grid Monitor. Historical wind and solar capacity values were obtained from MISO's 2023-2024 Wind and Solar Capacity Credit Report https://cdn.misoenergy.org/2023%20Wind%20and%20Solar%20Capacity%20Credit%20Report628118.pdf

[3] See Value of Lost Load in the Appendix.

IRP proceedings involve only one electric utility, not the entire nation, and often last for several months and, in some cases, years. IRP proceedings involve extensive back-and-forth discovery and examinations of the assumptions used.

EPA should be required to perform a similar analysis over several months while transparently disclosing the modeling assumptions in the IPM rather than making these important decisions using a black box modeling platform that does not evaluate the hourly reliability of the power grid.

This analysis is meant to act as a "stress test" of EPA's modeled assumptions. It is not an endorsement or dismissal of the assumptions used in EPA's modeling.

Introduction: Center of the American Experiment

American Experiment appreciates the opportunity to comment on the 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.

American Experiment has been the most impactful and effective public policy organization in Minnesota. It leads the way in creating and advocating policies that make Minnesota a freer, more prosperous and better-governed state.

Our energy model has been used to model the cost and electric reliability impacts of proposed legislation, regulations, and intervene in Integrated Resource Plans in Arizona, Colorado, Michigan, Minnesota, North Carolina, Virginia, Washington, West Virginia, Wisconsin, the Midcontinent Independent Systems Operator (MISO), and the Southwest Power Pool (SPP).

How the New Section 111 Regulations Reshape the MISO Generating Fleet

The current composition of the generating fleet in MISO consists largely of dispatchable thermal resources.

As of 2021, 77 percent of the installed capacity (ICAP) of the MISO grid consisted of thermal resources, with natural gas accounting for 41.9 percent, coal accounting for 26.4 percent, nuclear at 6.8 percent, and petroleum accounting for 2.19 percent.[4] Non-dispatchable wind and solar resources accounted for 15.8 percent and 1.04 percent of the ICAP on MISO, respectively.

This resource portfolio will undergo significant changes resulting from announced utility retirements of coal plants, the proposed Section 111 rules, and subsidies made available in the Inflation Reduction Act (IRA). Figure 1 illustrates the installed capacity of the MISO fleet in 2021, and EPAs assumed changes to the MISO fleet in the model years 2028, 2030, 2035, 2040, 2045, 2050, and 2055 using the agency's Integrated Proposal with LNG Update assumptions.

[4] Data were obtained from EIA forms 861 and 923.

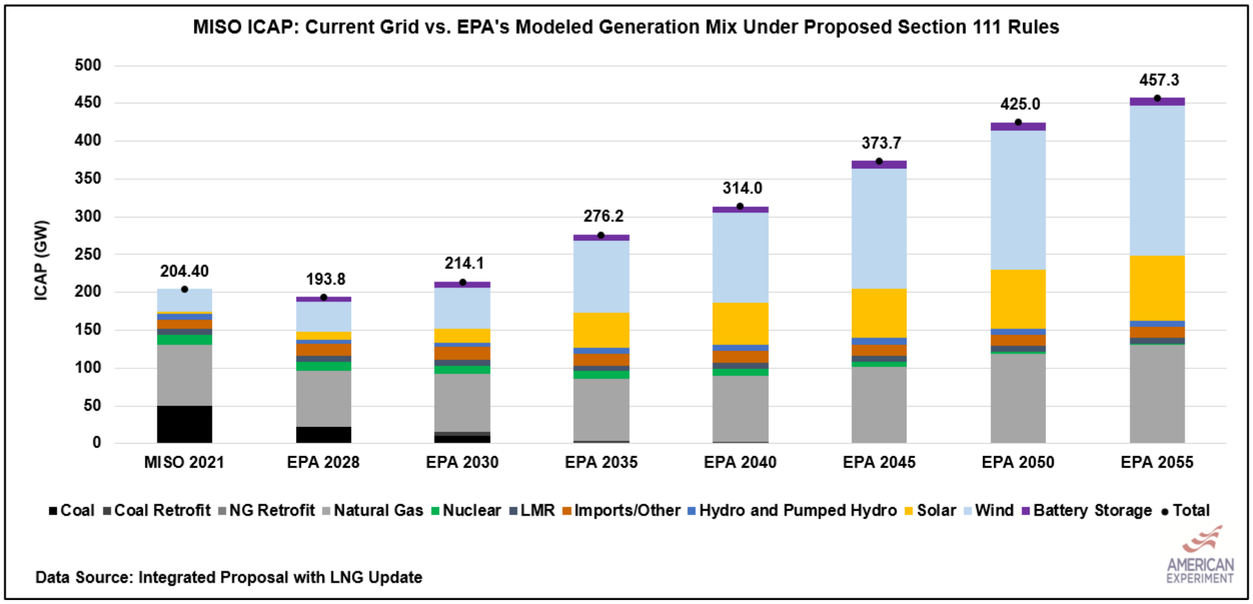

Figure 1. EPA's modeled resource portfolio in MISO undergoes significant changes in each of the model years, with installed capacity increasing 2.56 times in 2055 compared to 2021.

Between 2021 and 2055, EPA projects the installed capacity on the MISO system will grow from 204 GW of installed capacity to 457.3 GW despite the retirement or retrofitting of the entire coal fleet by 2035. As a result, EPA is assuming the installed capacity of the MISO grid will grow by a factor of 2.5 over the next 30 years, with most of this new installed capacity consisting of onshore wind, solar, combustion turbine (CT) natural gas, and battery storage.

Although EPA is modeling a 2.5-fold increase in the amount of installed capacity on the MISO grid, it is also projecting that there will be less dispatchable capacity online in 2055 than in 2021 as a percentage of peak demand. This occurs because dispatchable capacity, defined in this analysis as any resource other than wind or solar, on EPA's modeled MISO system, grows by only 2.1 GW despite EPA's assumption that peak load in MISO will increase by 42 percent, rising from 124.21 GW in 2021 to 177.6 GW in 2055.

The gap between the amount of dispatchable capacity and the projected peak load and target reserve margin in EPA's modeled MISO grid in 2055 seriously undermines EPA's assertion that the proposed Section 111 rules maintain Resource Adequacy (RA) and reliability on the MISO system.

Assessing the Resource Adequacy of EPA's Modeled Grid

American Experiment's modeling identified two major flaws in EPA's RA analysis. The first flaw is that the analysis is too narrowly tailored to the proposed Section 111 rule, and EPA does not conduct a RA analysis on its Post-IRA base case. The second flaw is that EPA is giving unrealistically high capacity accreditation values to all resources in its modeled MISO grid, which results in insufficient capacity on the system to prevent rolling blackouts.

Narrowly Tailoring the Resources Adequacy and Reliability Analysis to Assess the Difference between the Integrated Proposal with LNG Update and the Updated Base Case with LNG Update

EPA's RA assessment is narrowly tailored "*to serve as a resource adequacy assessment of the impacts of the final rule and how projected outcomes under the final rule compare with projected baseline outcomes in the presence of the IRA."* [emphasis added].[5]

Furthermore, the agency stated that "The focus of the analysis is on comparing the illustrative proposed rules scenario from the RIA to a base case (absent the proposed requirements) *that is assumed to be adequate and reliable." [emphasis added].*[6]

EPA assumes the subsidies in the IRA are responsible for the vast majority of the changes on the American electric grid over the next 32 years. For example, an analysis from the U.S. Chamber of Commerce determined EPA's RIA concluded 1.5 percent of the carbon dioxide emissions reductions occurring from 2022 through 2040 would be the result of the power plant rules, with the remaining reductions resulting from the IRA.[7]

Given the massive changes in the U.S. electric grid that EPA is attributing to the IRA, it is indefensible that EPA did not conduct a RA or reliability analysis of its Post-IRA base case.

In essence, EPA's narrow tailoring of the RA analysis on the difference in RA between the proposed rule in the Integrated Proposal with LNG Update and the Updated Baseline with LNG Update without assessing the resource adequacy or reliability of the baseline is the regulatory equivalent of making sure the top floor of a 100-story building is built to code without doing the same for the preceding 99 floors.

American Experiment's modeling determined that EPA's assumptions are incorrect and that the Updated Base Case with LNG Update does not maintain resource adequacy or reliability. As a result, the 99 floors that form the foundation of EPA's rules are an arbitrary and unstable platform rather than a solid rational basis for the rulemaking.

EPA's Capacity Accreditations Are Unrealistically High

RA studies are used to determine if there are enough reliable power plants on a system to maintain grid reliability. The capacity of these power plants, often measured in megawatts (MW) or gigawatts (GW), is totaled up into a capacity "stack" to determine if the power plant capacity

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[5] 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.

[6] *Ibid.*

[7] Heath Knakmuhs and Dan Byers, "A Closer Look at EPA's Powerplant Rule," U.S. Chamber of Commerce, June 2023, https://www.globalenergyinstitute.org/sites/default/files/2023-06/USCC_EPA%20Powerplant%20Rule%20Analysis_2023.FINAL_.pdf.

available can meet the projected peak demand, plus a margin of safety, which is called the target reserve margin (See Figure 2).

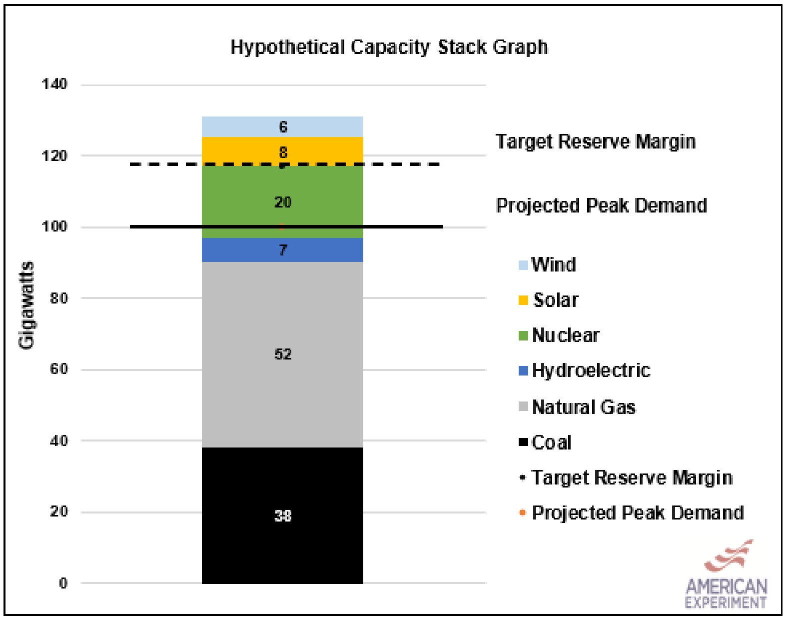

Figure 2. Resources are "stacked" on top of each other until there is enough electricity-generating capacity on the grid to meet the projected peak demand with a margin of safety.

Each power plant in the stack is given a reliability rating, known as a capacity accreditation value, which is frequently abbreviated to UCAP. The UCAP accreditation allows grid planners to estimate the amount of electricity these plants can reliably produce when the electricity is needed most, known as peak electricity demand or peak load.

Different types of power plants have different operational characteristics and abilities, and as a result, these plants are given different capacity accreditations. Dispatchable plants, consisting of coal, natural gas, nuclear, hydroelectric, and battery storage, can be turned on to produce electricity when it is needed. As a result, these power plants generally receive higher UCAP values than non-dispatchable wind and solar facilities, which only generate electricity if the wind is blowing or the sun is shining.

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 has important implications for RA and reliability.

EPA's RA analysis for the proposed Section 111 rules consists of performing a reserve margin analysis. The agency states that the IPM selects resources using a target reserve margin in each region as the basis for determining how much accredited capacity (UCAP) to keep operational (or build) to preserve resource adequacy.[8]

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 derate relative to the nameplate capacity when solving for reserve margin (See Table 1).

EPA's Proposed 111 Regulations	
Resource	EPA's Capacity Accreditation in MISO
Existing Onshore Wind	19%
Existing Solar	55%
New Onshore Wind	9%-25%
New Solar	32%-52%
Existing Thermal	100%
Existing Hydro	56%
New Hydro	65%
Existing Energy Storage	48%
Pumped Storage	95%
New Battery Storage	100%

Table 1. EPA gives wind and solar capacity accreditations ranging from 19 to 25 percent for wind, and 32 to 55 percent for solar.

EPA only meets its target reserve margin requirements in its Integrated Proposal with LNG Update thanks to generous assumptions for load modifying resources (LMRs) and imports in American Experiment's modeling and EPA's generous capacity accreditation assumptions.

Despite these generous assumptions, EPA's modeled MISO grid is relying on intermittent wind and solar to meet its target reserve margin in 2028, and it relies on wind, solar, and battery storage to meet its projected peak demand for every year from 2030 and beyond (See Figure 3).

[8] *Supra Note 5.*

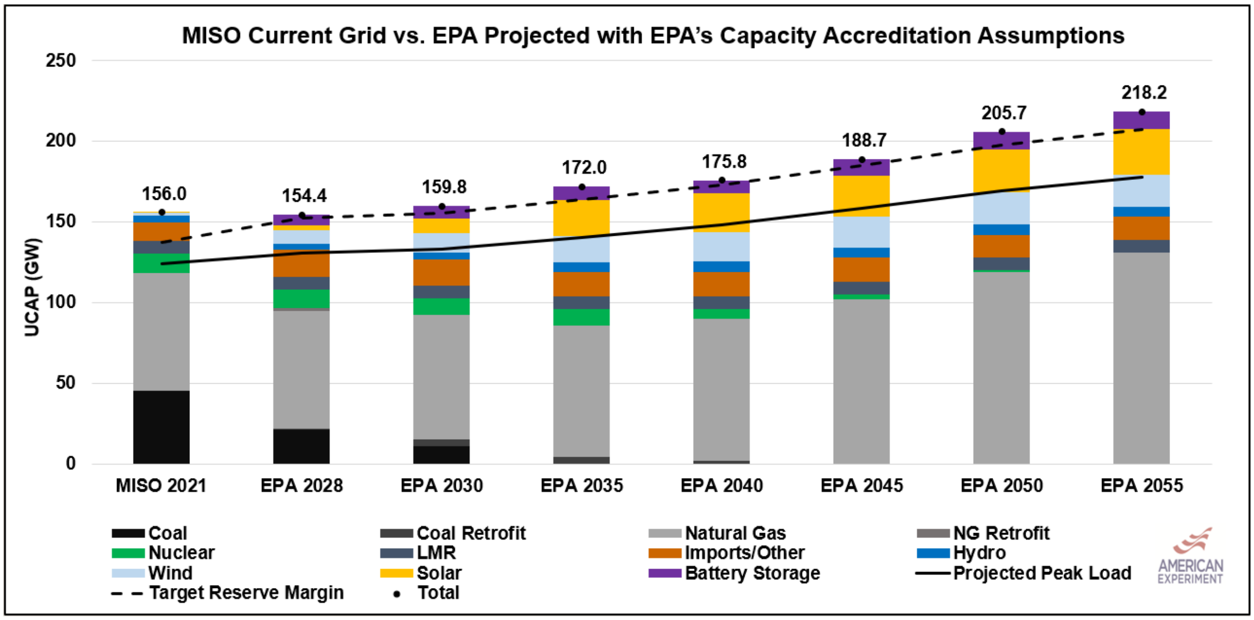

Figure 3. EPA's modeled MISO grid under the Integrated Proposal with LNG Update relies on intermittent resources such as wind and solar to perform at their capacity accreditation to keep the lights on and meet reserve margin targets.

EPA's reliance on with and solar to meet the projected peak load and target reserve margin means that these resources must be at least operating at their accredited capacity to keep the lights on during periods of high demand. If they underperform their accreditation, which happens frequently, then EPA's modeled grid cannot maintain reliability, resulting in capacity shortfalls.

EPAs Modeled Resource Portfolio Can't Keep the Lights On

Reserve margin analyses can be useful tools for determining resource adequacy and reliability, but the shift away from dispatchable thermal resources toward intermittent wind and solar generators increases the complexity and uncertainty in these analyses and makes them increasingly dependent on the quality of the assumptions used to construct capacity accreditations.

This is likely a key reason why EPA distinguishes between RA and reliability in the RA Technical Support Document (TSD) for the proposed regulations:

"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.

As the grid becomes more reliant upon non-dispatchable generators with lower reliability values, it is crucial to "stress test" the RA assumptions used to justify EPA's proposed rules by conducting an hourly reliability analysis on EPA's modeled generation portfolio in the MISO region by comparing historic hourly electricity demand and wind and solar capacity factors against EPA's installed capacity assumptions from the Integrated Proposal with LNG Update.

American Experiment 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).

Comparing hourly historic electricity demand and wind and solar output to EPA's modeled MISO grid under the proposed Section 111 rules, our modeling found that EPA's grid would be unable to keep the lights on for all hours of the model run. In fact, our modeling determined that blackouts would occur in every single one of EPA's modeled years, depending on the HCY used (See Table 2).

Number of Hours of Capacity Shortfalls (Total Hours of Blackouts)								
Historic Comparison Year	2028	2030	2035	2040	2045	2050	2055	Total
2019	12	43	70	79	40	22	8	274
2020	0	0	20	29	21	15	7	92
2021	14	24	37	40	30	22	16	183
2022	9	18	15	16	0	0	0	58

Table 2. EPA's modeled MISO grid is insufficient to reliably meet electricity demand for each model year. The extent of the blackouts depends on which historic comparison year is used. Blackouts occur in each EPA model year (2028-2055) for 2019 and 2021 HCYs.

A total of 607 hours of capacity shortfalls were observed in the modeled years (2028, 2030, 2035, 2040, 2045, 2050, and 2055) across all HCYs, with 274 hours of blackouts observed using the 2019 HCY and 183 hours in the 2021 HCY. The longest capacity shortfall would last 15 hours, occurring in a theoretical week in January 2040 after the regulations have been implemented if the grid experienced the same hourly electricity demand and wind and solar generation as it did in 2020 (See Figure 4).

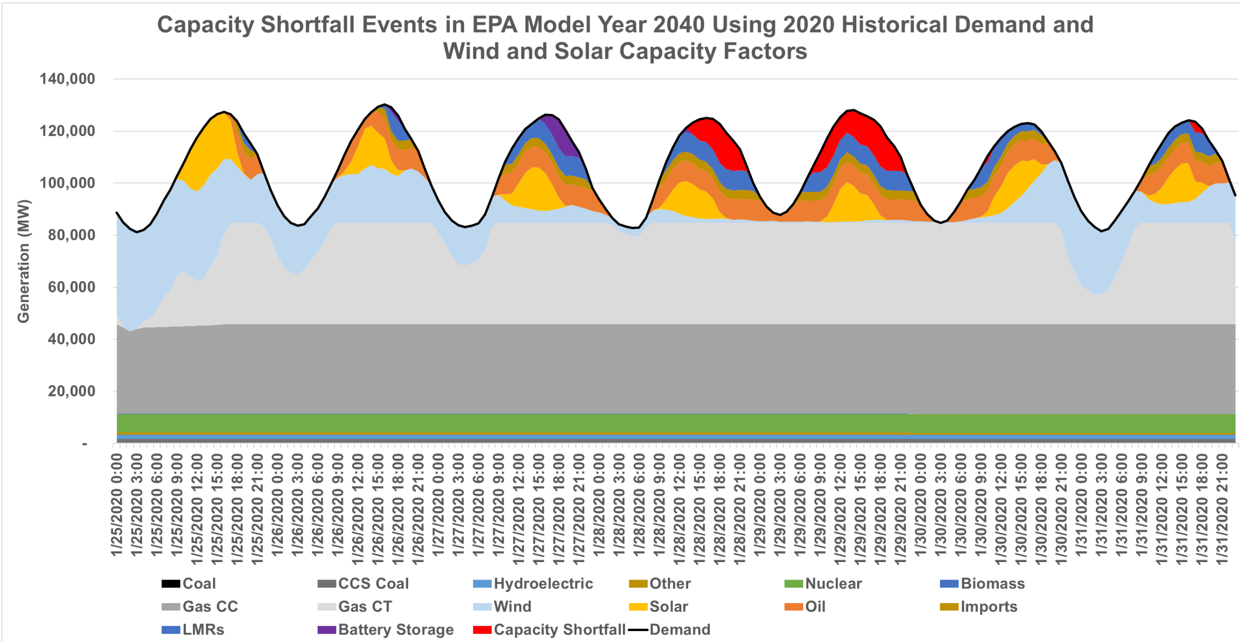

Figure 4. This figure shows the generation of resources on EPA's modeled MISO grid during a theoretical week in 2040 after the proposed Section 111 rules are implemented. The purple portions of the graph show the battery storage discharging to provide electricity during periods of low wind and solar generation. Unfortunately, the battery storage does not last long enough to avoid blackouts during a wind drought.

These blackouts would occur because MISO experienced "wind drought" during this period where wind capacity factors were below 10 percent for 80 consecutive hours. For 42 consecutive hours, wind generation was below 1.5 percent, essentially rendering the entirety of the wind fleet unavailing.

Additionally, EPA's modeled MISO grid in 2040 does not have enough dispatchable natural gas capacity to meet all of MISO's electricity demand. As a result, the region would be dependent upon generation from wind and solar resources, imports from neighboring regions, and battery storage facilities to meet demand. Unfortunately, due to the long duration of the wind drought, the wind resources in MISO would not be able to recharge the batteries needed to maintain reliability, resulting in 15 consecutive hours of blackouts in January of the 2040 model year.

The Scope of the Blackouts

Many of the observed blackouts are significant. For example, our analysis found EPA's modeled grid would result in a massive blackout totaling over 26,000 MW (26 GW) in capacity shortfalls in the 2040 EPA model year using the 2021 HCY (See Figure 5).

For context, this represents 19.5 percent of the electricity demand on the MISO system at the time of the capacity shortfall, meaning one in five homes would be subjected to rolling power outages.

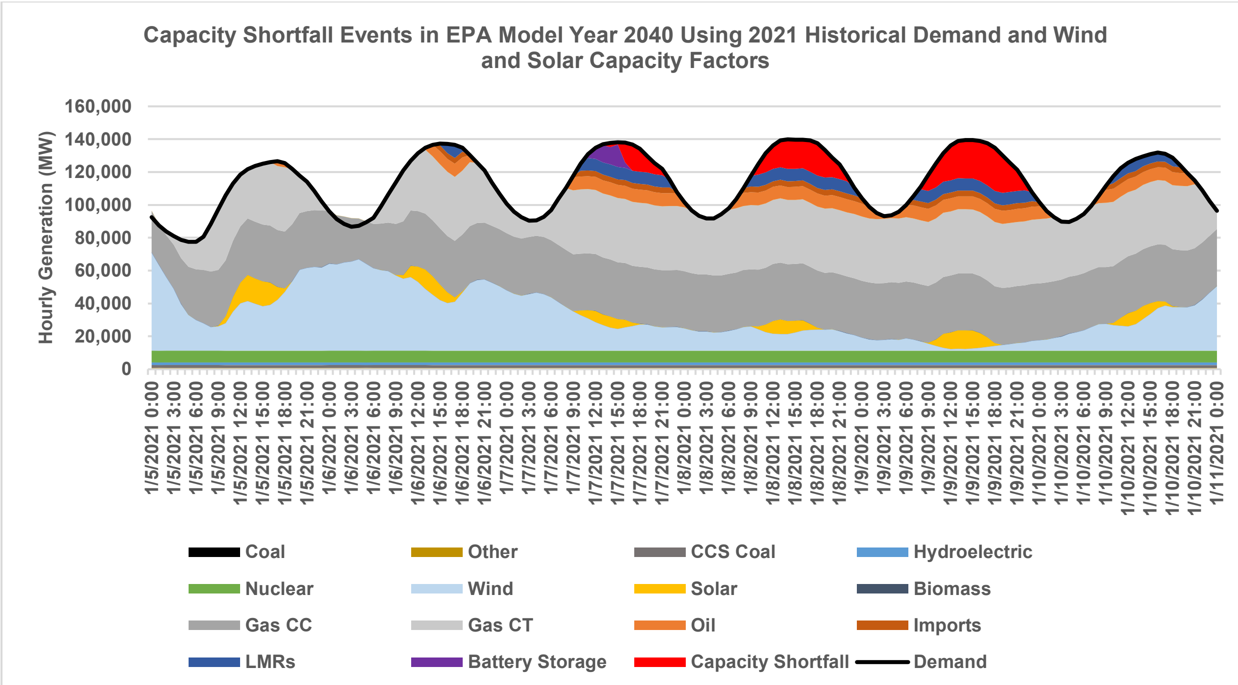

Figure 5. The blackouts occurring in January of 2040 using the 2021 HCY would be massive, constating 26 GW, which is 19.5 percent of the electricity demand on the system at the time.

Such large capacity shortfalls would be difficult to manage, resulting in undue hardship on grid operators and the customers they serve.

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 recommended a value of $25,000 per MWh for the MISO region.[9] American Experiment used a midpoint value of $14,250 per MWh of unserved load to calculate the social cost of the blackouts under EPA's proposed Section 111 rules.

Our modeling indicates blackouts occurring in the 2019 HCY would cost the MISO region $56.7 billion in the model run years 2028, 2030, 2035, 2040, 2045, 2050, and 2055, or an average of $8.1 billion in each of the modeled years (See Table 3).

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[9]https://cdn.misoenergy.org/20230713%20MSC%20Item%2006%20IMM%20State%20of%20the%20Market%20Recommendations629500.pdf

These blackouts constitute an enormous externality cost that EPA is not capturing in its Regulatory Impact Analysis because it does not model the reliability of its Integrated Proposal with LNG Update or Updated Baseline with LNG Update model assumptions; they assume, erroneously, that they are reliable. These blackout costs, if realized, would exceed EPA's estimated annual net benefits for the rule in the entire country (estimated at $5.9 billion) in the MISO region alone.

Value of Lost Load				
EPA Model Year	Historic Comparison Year			
	2019	2020	2021	2022
2028	$801,348,750	$0	$1,321,488,000	$288,078,000
2030	$2,865,703,500	$0	$2,933,904,000	$1,045,408,500
2035	$7,237,190,250	$1,877,622,750	$6,414,039,000	$933,474,750
2040	$21,207,177,750	$3,340,299,750	$7,503,280,500	$1,056,324,000
2045	$12,693,757,500	$2,380,491,000	$5,625,258,750	$0
2050	$7,404,870,000	$1,280,220,000	$4,042,810,500	$0
2055	$4,486,256,250	$529,971,750	$2,992,884,750	$0
Total	$56,696,304,000	$9,408,605,250	$30,833,665,500	$3,323,285,250

Table 3. The Value of Lost Load represents the Social Cost of Blackouts. EPA's modeled MISO grid results in a wide range of VoLL costs based on the HCY used. In 2022, the cost of blackouts was $3.3 billion, but in 2019, the same grid resulted in $56.7 billion in blackout costs.

The high economic and human costs of blackouts make reliability analyses a crucial and indispensable part of modeling any changes to the electric grid. Not conducting such an analysis leaves the American electric grid in jeopardy of experiencing dangerous blackouts.

Conclusions on Reliability

This analysis demonstrates that EPA's modeled MISO grid under the proposed Section 111 rules would be dangerously unreliable, generating severe capacity shortfalls during the coldest winter months. As a result, this modeling seriously undermines the agency's claim that it has "carefully considered the importance of resource adequacy and grid reliability in developing these proposals and is confident that these proposed rules and emission guidelines … can be successfully implemented in a manner that preserves the ability of power companies and grid operators to maintain the reliability of the nation's electric power system."

EPA's modeled generation mix cannot prevent blackouts while hindcasting observed historical conditions. Therefore, we should not have any confidence in EPA's assurances that the proposed Section 111 rules will have no impact on future electric reliability.

By not building enough capacity to meet demand under observed historical demand and wind and solar output conditions, EPA's modeling is severely underestimating the cost of its proposed Section 111 rules which greatly influences EPA's cost-benefit analysis for the proposed regulations.

Once the cost of this additional capacity in MISO is accounted for, the compliance costs for the rules in this one region of the country outweigh EPA's estimated rules for the entire nation.

Why EPA's Modeled Portfolio Can't Keep the Lights On: EPA's IPM is Overestimating the Contribution of Wind and Solar Resources

EPA's modeled scenarios are incapable of reliably serving load for two main reasons. First, EPA is relying on wind, solar, and battery storage resources, rather than dispatchable resources, to meet its projected peak demand and reserve margin requirements.

Secondly, EPA is overestimating the UCAP of wind, solar, and thermal resources in its capacity accreditation methods. This, in turn, exacerbates the problem created by relying on non-dispatchable resources to meet projected peak load and the target reserve margin because it leads EPA to believe it has adequate generating resources to satisfy electricity demand when in reality, the amount of installed capacity on the grid is insufficient to meet hourly electricity demand while hindcasting for previous conditions.

As a result, EPA's assumption that its Post-IRA base case, reflected here as the Updated Baseline with LNG Update, maintains resource adequacy and reliability is incorrect. This means the foundation on which the proposed Section 111 rules are based is arbitrary and not a rational basis for promulgating new regulations.

Relying on Non-Dispatchable Generators to Meet Projected Peak Demand is Dangerous

All generation types can underperform their accreditation during periods of high strain on the grid, such as extreme hot or cold temperatures. This occurred during the blackouts in Texas in 2021, when natural gas delivery to power plants was interrupted, and wind and solar generation was low.[10] Natural gas supply disruptions also occurred in the Christmas Blackouts of 2022.[11]

The reliance on just-in-time delivery of natural gas for electricity generation presents a real reliability challenge. However, this challenge can be mitigated by the construction of on-site

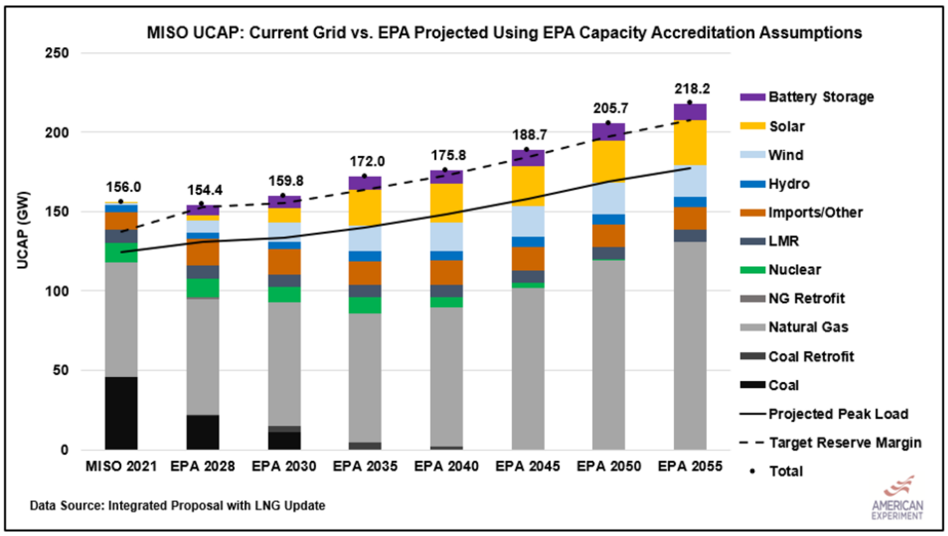
[10] Garrett Golding, "Texas Electrical Grid Remains Vulnerable to Extreme Weather Events," Dallas Federal Reserve, January 17 2023, https://www.dallasfed.org/research/economics/2023/0117.

[11] Gerson Freitas Jr, Naureen S Malik, and Mark Chediak, "Deadly Winter Storm Exposes Deep Flaws of US Energy System," Bloomberg, December 27, 2022, https://www.bloomberg.com/news/articles/2022-12-27/deadly-winter-storm-exposes-deep-flaws-of-us-energy-system.

liquified natural gas (LNG) storage, with Otter Tail Power Company pursuing such a strategy at their Astoria, South Dakota Plant.[12]

However, no such mitigation strategy exists for non-dispatchable generators, as RTOs and Load Serving Entities have no option of turning up their wind turbines or solar panels. As a result, relying on these resources to meet project peak demand and target reserve margins is essentially gambling with the reliability of the grid.

Figure 6 shows EPA's projected peak demand and reserve margin on its modeled MISO grid are "satisfied" using intermittent wind and solar resources, with battery storage intended to store the electricity generated by these generators for later use. EPA's modeled MISO grid relies on these resources to meet the target reserve margin in every model year (2028-2055) and to meet the projected peak demand in 2030 and beyond.



Year	Reserve Margin
2022	25.6%
2028	18.2%
2030	19.9%
2035	22.2%
2040	18.7%
2045	19.3%
2050	21.7%
2055	22.9%

Figure 6. 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. Red indicates intermittent generation is necessary to meet Target Reserve Margins.

EPA's reliance on the use of intermittent generators to ensure RA and reliability greatly increases the importance of having accurate accreditation values (UCAP values) for these intermittent generators. Unfortunately, EPA's UCAP figures for wind and solar are too high, leading EPA to achieve its RA targets on paper, but not when this modeled MISO grid is subjected to an hourly reliability stress test.

EPA's Over-Accreditation Leaves the Modeled MISO Grid Short of Capacity

The capacity shortfalls occur because EPA's IPM is overestimating the contribution variable wind and solar resources will provide regarding resource adequacy. For example, American

[12] Otter Tail Power Co, "2022 Earnings Conference Call," February 14, 2023, https://s1.q4cdn.com/276295446/files/doc_presentations/2023/2022-Year-end-Earnings-Call-Presentation-Final.pdf.

Experiment averaged the capacity accreditations generated by EPA throughout each MISO subregion to determine an average, MISO-wide capacity credit for each resource type. These capacity credits can be viewed in Table 1 on page seven.

Existing wind and solar facilities are given capacity values of 19 percent and 55 percent. These values are large relative to new wind and solar capacity entering service (with capacity values ranging from 9 to 25 percent for new wind and 32 to 52 percent for new solar) during the model run, and these UCAP values are held constant throughout the model run (See Figure 7).

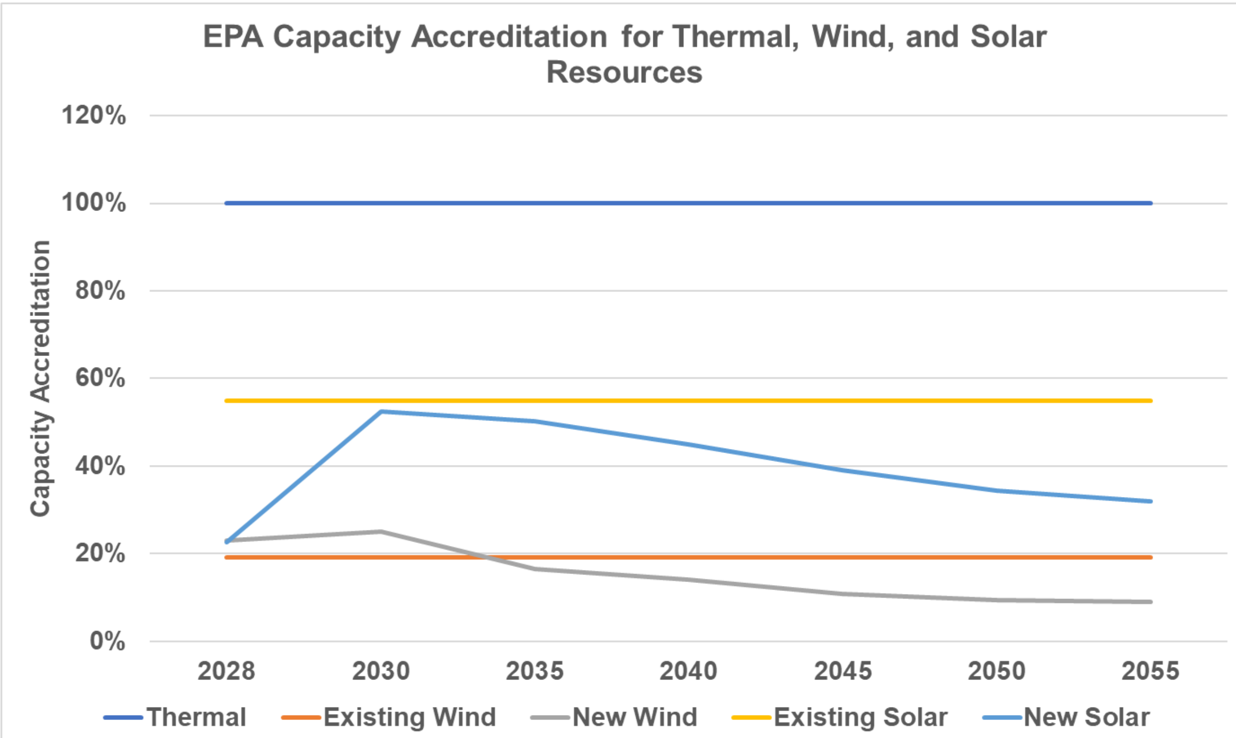


Figure 7. EPA's IPM assumes constant UCAP values for existing wind and solar resources and declining values for new wind and solar resources. Thermal accreditation is held constant at 100 percent.

EPA correctly assumes a declining UCAP for new wind and solar resources because the incremental value of each MW of installed intermittent capacity falls as more of these generators are added to the grid. However, EPA's assumption that existing generators will have a constant capacity value that is different from new generators of the same type is problematic because intermittent wind and solar resources, especially solar power, tend to be highly correlated regardless of when the asset was placed into service. Therefore, one capacity value for wind and one capacity value for solar, both new and existing, would be a more appropriate way to assess their contributions to resource adequacy.

Furthermore, EPA's UCAP values for new intermittent capacity are still too high, as is EPA's assumption that thermal resources will get a 100 percent capacity credit.

EPA's capacity credits for intermittent resources are troublesome because these resources routinely underperform their accreditation during periods of high electricity demand. These resources exist on paper, but they may or may not provide power when it is needed most, which is why American Experiment calls capacity accreditation values for wind and solar "phantom firm" resources.

Figure 8 demonstrates how EPA's UCAP accreditations for wind would leave its modeled MISO grid short of energy. The figure shows hourly electricity demand in black and the hourly capacity factor of the entire MISO wind fleet in blue. The red line indicates EPA's UCAP value for existing wind, and the orange line indicates its UCAP value in 2055.

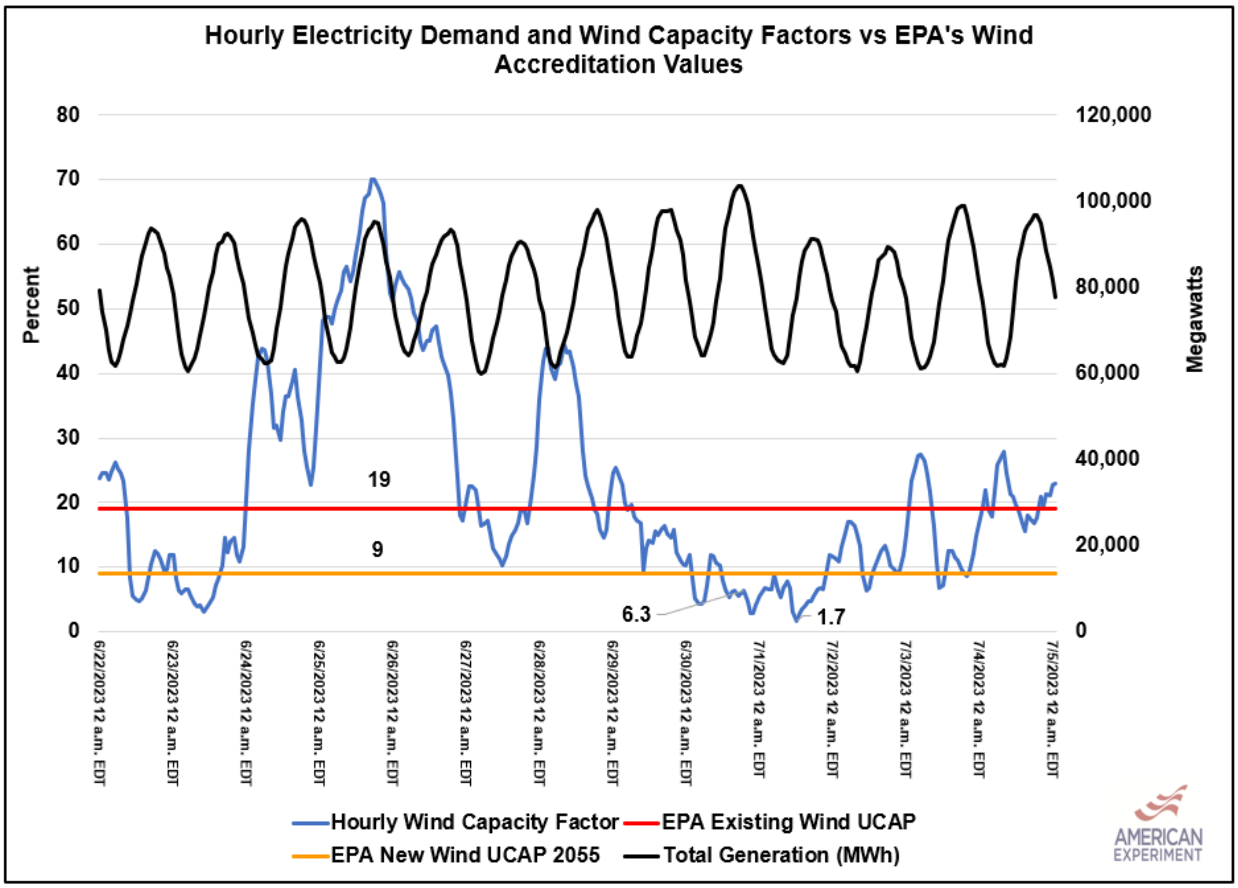


Figure 8. From June 22, 2023, to July 5, 2023, wind capacity factors on the MISO system routinely underperformed EPA's capacity accreditation. Because wind is a non-dispatchable resource, grid planners must plan to provide electricity during periods of its lowest output.

Despite the lower accreditation in 2055, wind is still underperforming its UCAP during the peak demand period by approximately 30 percent. This underperformance is manageable on a system where there is adequate dispatchable capacity to meet demand, but it becomes increasingly unmanageable as grids become more reliant on intermittent wind and solar resources to meet projected peak demand and target reserve margins. As a result, grid planners of the future will need to plan to provide electricity during the periods of lowest wind and solar output. Doing so will require more realistic capacity accreditation methods for all resources, especially wind and solar.

Methods and Results

EPA is committing the twin sins of relying on non-dispatchable generators to meet projected peak demand and target reserve margin while simultaneously overestimating the reliability of these resources. Reasonable accreditation values must be used to maintain RA on grids that depend upon the contribution of intermittent generators to maintain reliability.

Creating Reasonable Capacity Accreditation Metrics

Maintaining RA as grids become more reliant upon non-dispatchable generators will require realistic capacity accreditation of these resources. These realistic accreditations will allow grid operators to more accurately determine how much additional installed capacity would be required to maintain grid reliability under the proposed Section 111 rules, compared to the Integrated Proposal with LNG Update, which is necessary to estimate the true cost of the regulations.

Managing Peak Load and Net Peak Load

As grids become more reliant upon wind and solar, meeting net electricity demand, defined gross electricity demand minus wind and solar generation will become the largest priority of grid operators.

Figure 9 shows that peak load occurs during the hours with the highest total electricity demand, and net peak load is the period in time when electricity demand is highest, but wind and solar production is lowest.

As electric grids experience rising penetrations of intermittent resources, coupled with the retirement of thermal resources, meeting *net* peak load will become increasingly challenging because grid planners cannot increase the output of wind and solar generators on command, and there will be insufficient dispatchable capacity on the grid to manage the downside of wind and solar generation.

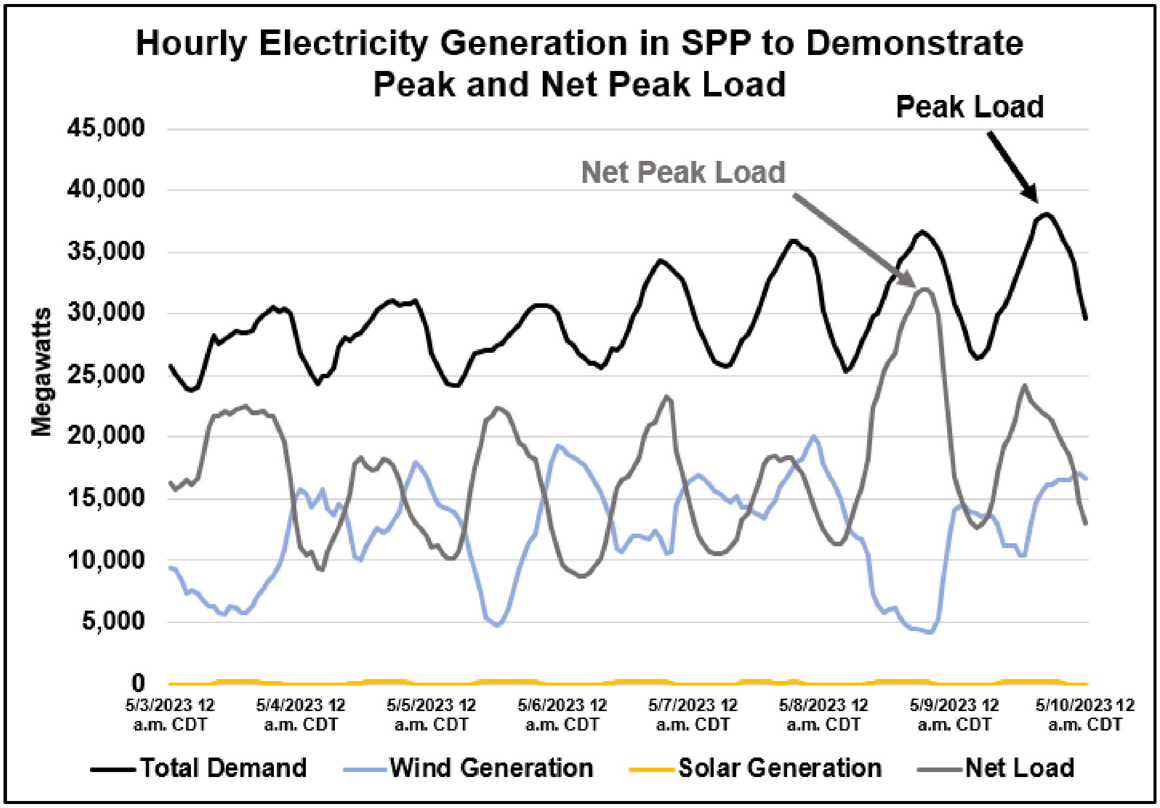


Figure 9. Providing electricity during net peak hours will become increasingly difficult as regions retire thermal capacity and become increasingly reliant upon intermittent generators.

This constitutes a fundamental change in resource planning. Historically, utilities and grid operators have sought to meet electricity demand during the peak load hours by building enough dispatchable capacity to meet that projected peak demand, plus a reserve margin. However, grid planners of the future will need to build the power system to manage both high demand *and* low wind and solar generation, introducing much more uncertainty to the resource adequacy process.

Managing this uncertainty will require UCAP accreditation methods that manage the downside potential of intermittent generators giving utility companies and grid operators high certainty of their availability.

Highest Certainty Deliverability (HCD) Accreditation

Highest Certainty Deliverability (HCD) uses a methodology known as the mean of the lowest quartile to assess appropriate accreditation values for wind and solar that are more on par with those of thermal resources.

Here are the steps we took to estimate HCD values for wind and solar.

Using EIA Hourly Grid Monitor and Form 923 data from July 2018 through June 2022, we arranged the data into the highest hourly peak and net peak values (net peak equals demand minus wind and solar generation).

Using distribution curves of MISO demand, we observed higher-than-average demand for roughly 500 hours out of the year, which we used as our annual sample size. Because there were four years of data, we used a total sample size of 2000 hours to assess our HCD values.

After isolating the highest 2000 peak and net peak hours in the data, we arranged the data from lowest to highest capacity factors for wind and solar resources. Finally, we averaged the lowest 25 percent of capacity factors within these net peak hours and used this number for our capacity accreditation.

Essentially, HCD values express wind and solar accreditation in terms of what they can offer 87.5 percent of the time – which is closer to the treatment of thermal generators and gives market operators a better assessment of how reliable wind and solar can be.

Accurate resource accreditation is important for grid operators who rely on RA as a measure of reliability, and especially when it is the only means of reliability measurement, such as is the case with EPA's modeling of the proposal in question.

Indeed, EPA used questionable accreditation values that overvalued the accreditation of its resources in several ways, which had the individual and combined result of reducing the amount of capacity built in EPA's model, thus artificially reducing the cost of compliance with the proposal.

Table 4 shows how EPA used unrealistically high wind and solar accreditation for both existing and new facilities. It also used different accreditation values for new and existing wind and solar resources. Additionally, EPA kept accreditation values for existing wind and solar constant throughout the modeling period, while reducing new wind and solar accreditation gradually throughout.

	HCD Net Peak Wind	EPA Existing Wind	EPA New Wind	HCD Net Peak Solar	EPA Existing Solar	EPA New Solar
2028	5.8%	19.1%	22.9%	12.0%	54.9%	22.6%
2030	5.8%	19.1%	25.0%	12.0%	54.9%	52.4%
2035	5.8%	19.1%	16.5%	12.0%	54.9%	50.3%
2040	5.8%	19.1%	14.1%	12.0%	54.9%	45.0%
2045	5.8%	19.1%	10.9%	12.0%	54.9%	39.1%
2050	5.8%	19.1%	9.5%	12.0%	54.9%	34.3%
2055	5.8%	19.1%	8.9%	12.0%	54.9%	31.9%

Table 4. EPA's capacity accreditations for wind and solar are significantly higher than the net peak HCD accreditations, which is why EPA overestimates the reliability of these resources.

There is no logical basis for separate treatment of accreditation for new and existing wind and solar resources in this way. Doing so resulted in overestimating the amount of reliable capacity on the system. For example, had EPA applied the UCAP values of new wind and solar resources to the existing wind and solar fleet, which is the method employed by MISO and other regional transmission operators (RTOs), there would be an additional 3 GW of capacity shortages in EPA's RA assessment requiring additional capacity to meet its target reserve margin by 2055.

Using HCD values and real-world accreditation for thermal resources (95 percent for nuclear and 90 percent for other thermal generators compared to 100 percent used by EPA across the board, an accreditation seen in no RTO), the deficit becomes even worse (See Figure 10).

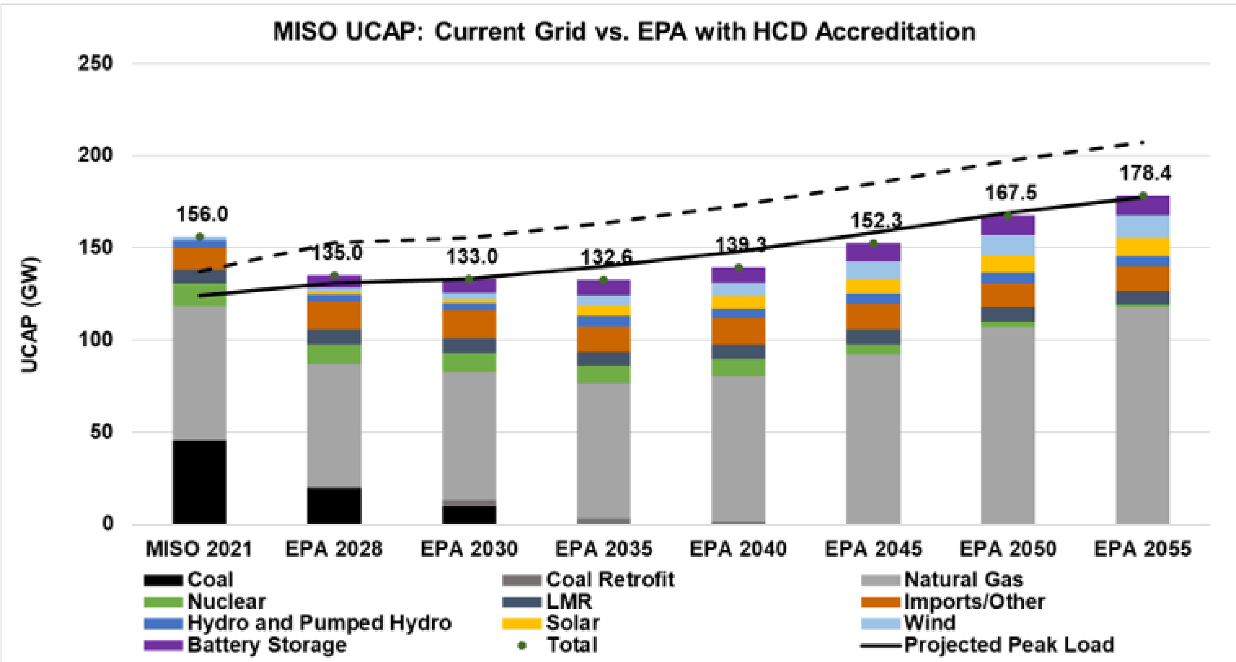


Figure 10. EPA's modeled MISO grid does not maintain resource adequacy using real-world thermal resource accreditation and HCD values for wind and solar. This explains why EPA's modeled grid experiences rolling blackouts in most modeled years and HCYs.

As you can see, using HCD values and real-world thermal accreditation values, EPAs modeled grid falls short of meeting peak demand in 2035, 2040, and 2045, and in no modeled year does it meet its targeted reserve margin.

Because EPA relied on unrealistically high accreditation values, the EPA's modeled MISO system was unable to adequately supply enough energy for every hour of the year when subjected to a reliability analysis.

While no method of resource adequacy can truly replace a reliability assessment, especially on grids with high penetrations of wind and solar because the output from these facilities may be producing less than their accredited capacity at any moment, the HCD method manages the downsides of wind and solar in ways that treat their availability similarly to that of thermal resource accreditation values.

This is the standard wind and solar resources should be judged by going forward.

Calculating the True Cost of Reliably Meeting the New Section 111 Rules Emissions Targets

EPA's modeled grid is so unreliable that it is not a realistic basis for understanding the financial impact of the proposed Section 111 rules.

Therefore, American Experiment modeled the cost of meeting EPA's modeled emissions reductions in MISO while meeting RA and maintaining grid reliability for all of the hours in each of the HCYs. This scenario is called the "Reliable 111 rule" scenario.

Achieving these three objectives will require an extensive capacity buildout of additional wind, solar, battery storage, and CT gas plants to provide sufficient electricity during periods of low wind and solar generation that will cost ratepayers an additional $246 billion (in 2022 dollars discounted at 3.7 percent) compared to constructing the grid in EPA's Integrate Proposal with LNG Update.

Methods

EPA assumes dramatic reductions in carbon dioxide emissions in MISO during the modeled timeframe resulting from the incentives in the IRA and the proposed Section 111 rules. EPA's modeled emissions in MISO fall from 257.2 million metric tons in 2028 to 30.1 million metric tons in 2055 (See Figure 11).

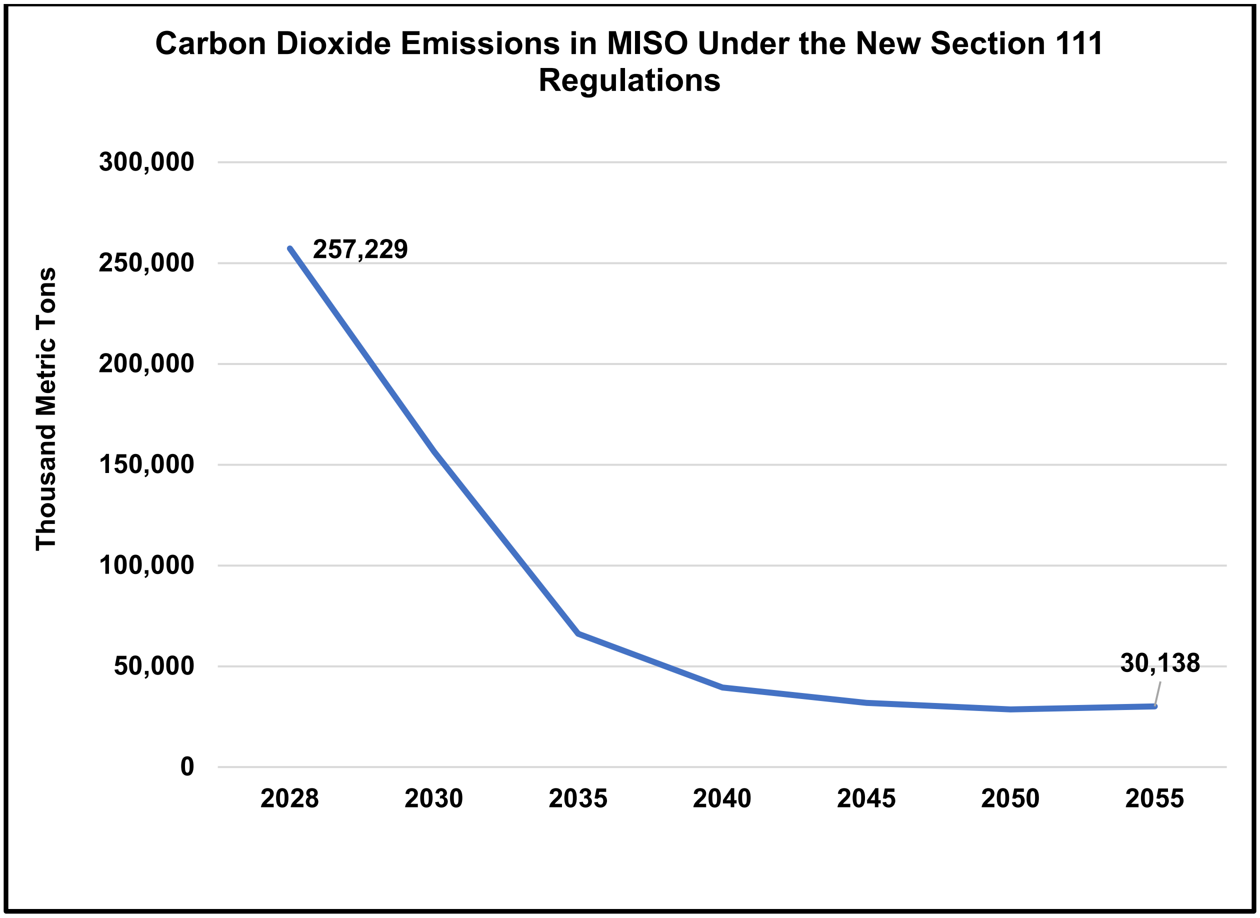


Figure 11. EPA's modeling indicates a substantial drop in carbon dioxide emissions resulting from the IRA subsidies and the proposed Section 111 rules. However, it is only possible to reliably meet these emissions reductions if more generation capacity is built.

To calculate the cost of meeting these emissions targets while maintaining RA and reliability, American Experiment used EPA's projected retirements and retrofits for coal, natural gas, and nuclear power plants in the MISO region based on the Integrated Proposal with LNG Update in each model year.

Our model then assumed new capacity additions for wind, solar, battery storage, and CT natural gas plants are made as needed to ensure reliability in each of the EPA modeled years and reach the emissions targets. These capacity additions occur in rough proportion to the UCAP capacity additions in EPA's Integrated Proposal with LNG Update.

The assumptions used to calculate the retail costs borne by ratepayers resulting from this capacity buildout, capital costs, additional taxes, utility returns, transmission, interconnection, and fuel costs are outlined in the Appendix.

Findings: Reliability

Our modeling concluded that avoiding capacity shortfalls on the MISO system under the proposed Section 111 rules in our "Reliable 111 rule" scenario would require an additional capacity buildout of 146 GW of capacity, representing a 32 percent increase relative to EPA's Integrated Proposal with LNG Update (See Figure 12).

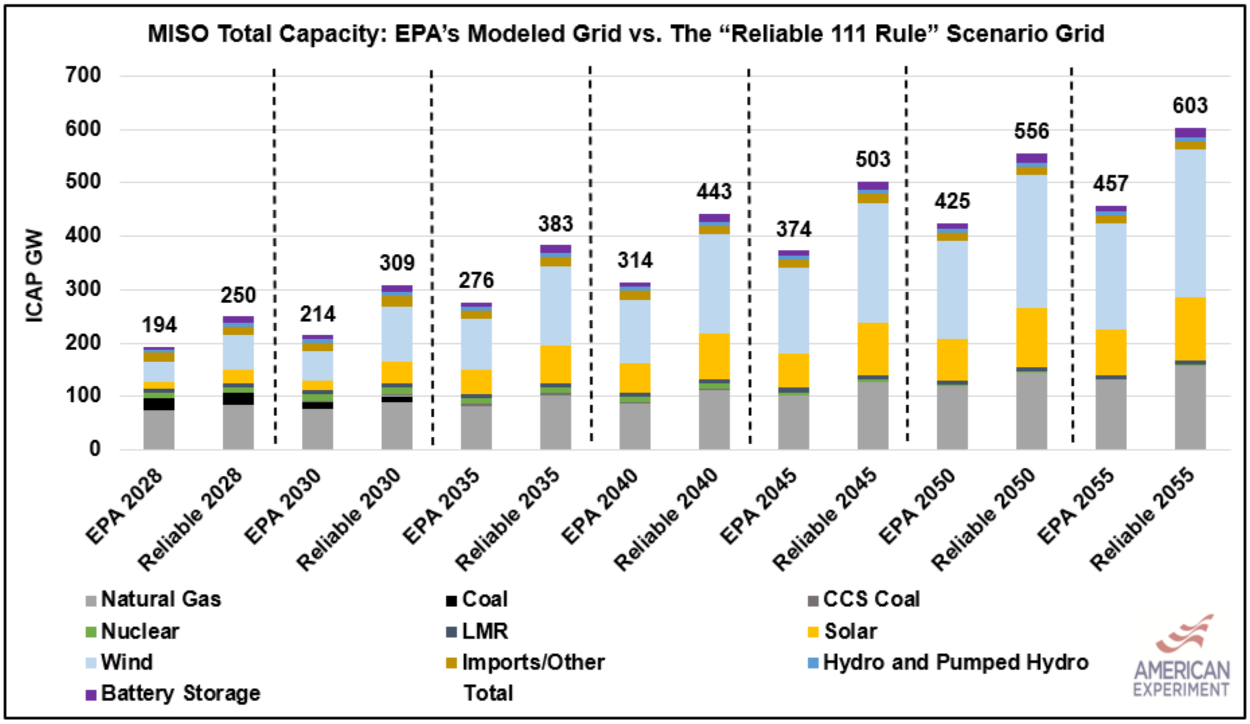


Figure 12. *The MISO grid will require 146 GW of additional capacity to meet EPA's emissions targets in MISO while maintaining grid reliability, a 32 percent increase relative to EPA's assumptions in the Integrated Proposal with LNG Update.*

The additional capacity consists of 21 GW of additional natural gas, 6 GW natural gas retrofits, 34 GW of solar, 79 GW of wind, one GW of imports, two fewer GW of hydroelectric, and seven additional GW of battery storage. With these additional GW of capacity, the Reliable 111 rule scenario was able to maintain grid reliability during the massive 26 GW capacity shortfall outlined in Figure 5 (See Figure 13).

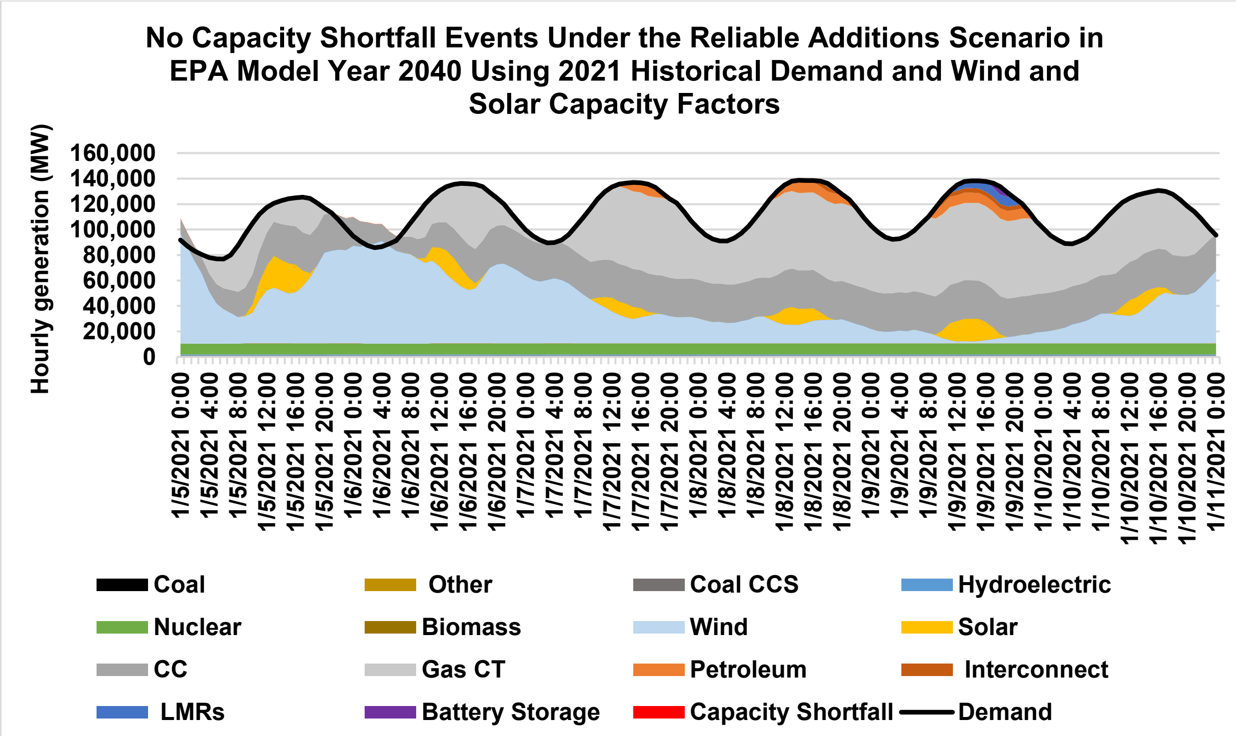


Figure 13. The additional capacity built in the Reliable 111 rule scenario averts the massive capacity shortfalls observed in 5.

While the Reliable 111 rule scenario was able to reliably meet electricity demand for all of the HCYs, it is important to note that evaluating any proposal with only four years of data regarding hourly electricity demand and wind and solar capacity factors is a small sample size that may leave the grid short of energy if there is not enough dispatchable capacity to meet projected peak load.

Findings: Resources Adequacy

Building the additional 146 GW of capacity relative to EPA's Integrated Proposal with LNG Update was sufficient to maintain reliability based on the observed fluctuations in electricity demand and wind and solar output for the four modeled HCYs, but the Reliable 111 rule scenario still relies on wind, solar, and storage operating at their accredited capacities to meet projected peak demand and reserve margin requirements (See Figure 14).

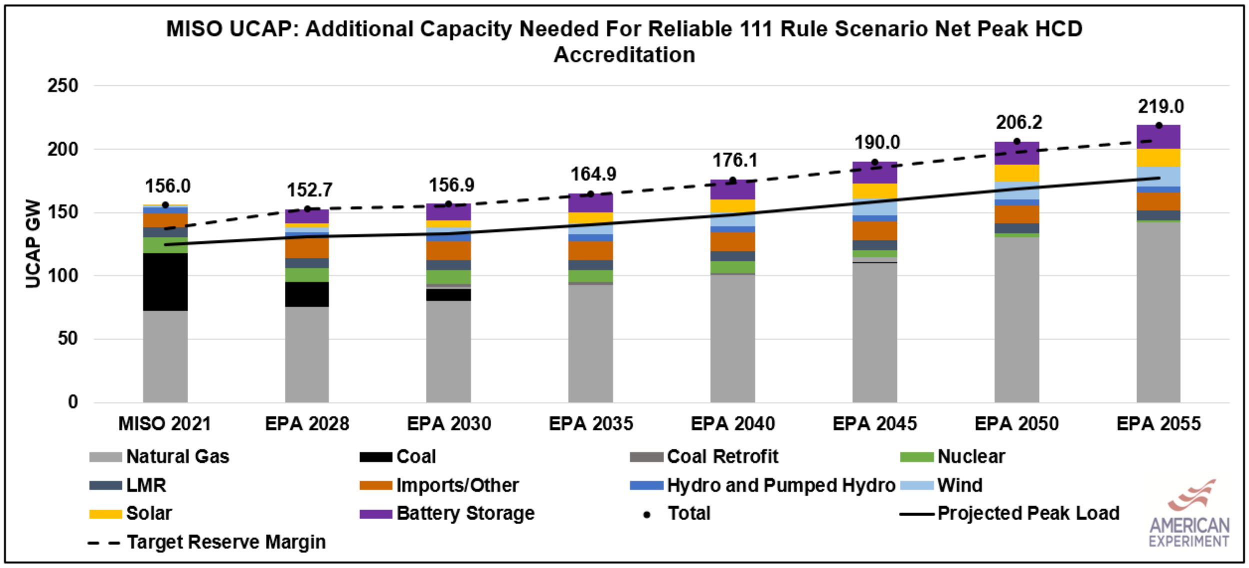


Figure 14. Although the Reliable 111 rule scenario avoids blackouts in the four modeled HCYs, it is still vulnerable to capacity shortfalls because it relies on wind and solar operating at their capacity accreditations to meet projected peak demand and the target reserve margin.

Relying on wind, solar, and battery storage, rather than dispatchable capacity like CT turbines leaves the MISO grid exposed to potential capacity shortfalls if wind and solar underperform the HCD capacity accreditations given to these resources. As a result, American Experiment's modeling for the amount of capacity needed to reliably comply with the proposed Section 111 rules, and the cost of complying with them, is still conservative. Ensuring maximum reliability would require having enough dispatchable capacity to meet the projected peak load and target reserve margin.

EPA's RA assessment was inadequate because the agency was giving variable generation sources unrealistically high capacity accreditation values and using this non-dispatchable capacity, rather than dispatchable capacity, to meet its projected peak demand and target reserve margins. The Reliable 111 rule scenario reduces the capacity accreditation of variable and dispatchable thermal resources, which in turn results in more ICAP on the grid and reduces, but does not eliminate, the possibility of rolling blackouts while complying with the proposed Section 111 rules.

Findings: Cost

American Experiment modeled the cost of EPA's modeled MISO grid in the Integrated Proposal with LNG Update and the cost of reliably serving load without any blackouts in every modeled year under the Reliable 111 rule scenario. The difference between these costs was considered the additional cost of EPA's proposal to reliably meet electricity demand.

Our modeling determined the true cost of the proposed Section 111 rules to ratepayers would be $246 billion in additional costs in the MISO region compared to the cost of EPA's modeled grid in the Integrated Proposal with LNG Update (See Figure 15).

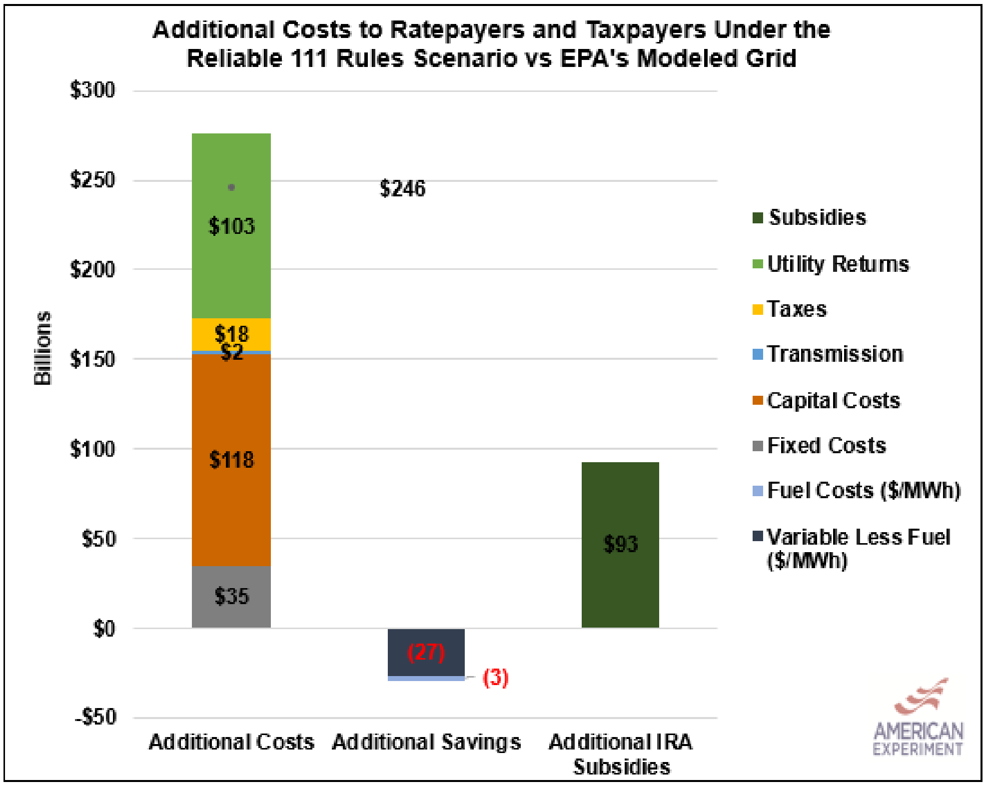


Figure 15. Although the Reliable 111 Scenario would save an additional $30 billion in fuel savings and additional variable costs, these savings are far outweighed by the massive increases in capital spending and utility profits.

The Reliable 111 rule scenario saves $30 billion, compared to the Integrated Proposal with LNG Update, in fuel costs and variable operations and maintenance costs. However, these savings are far outweighed by the additional fixed costs ($35 billion), capital costs ($118 billion), transmission costs ($2 billion), additional taxes ($18 billion), and utility profits ($103 billion). These incremental costs mean reliably meeting EPA's emissions targets under the proposed rules will cost an additional $246 billion to ratepayers and an additional $92.9 billion to taxpayers.

An additional compliance cost of $246 billion equates to $7.7 billion per year in incremental compliance costs for ratepayers, which exceeds EPA's estimated net benefits for the rules of $5.9 billion per year ***for the entire country in just one RTO.*** It is important to note that this figure does not include the additional $93 billion in IRA subsidies that would be paid by taxpayers in the Reliable 111 rule scenario as more capacity is added to meet electricity demand and meet EPA's emissions targets.

These additional costs will have a large impact on electricity rates. Per EPA's RIA, the agency expects electricity prices in the MISO region to be 10.45 cents per kilowatt-hour (kWh) in 2030, with costs declining to 9.39 cents per kWh by 2040. However, our cost modeling determined that electricity costs for MISO ratepayers would be 12 cents per kWh in the Reliable 111 scenario, an increase of nearly 28 percent relative to EPA's assumptions (See Table 5).

Average MISO Retail Electricity Prices ($2022 Cents Per kWh)			
Year	**Reliable 111 Rules Scenario**	**EPA's RIA**	**Difference**
2030	**11.27**	**10.45**	**.82**
2035	**11.66**	**9.59**	**2.07**
2040	**12.00**	**9.39**	**2.61**

Table 5. EPA's cost estimates for rates are far lower than those in the Reliable 111 rule scenario. This is due to the fact that EPA does not build enough new capacity to keep the lights on in its modeled scenarios, artificially suppressing the cost of its proposed rules.

Conclusions

EPA's modeled MISO grid will result in large capacity shortfalls that will cost the U.S. economy billions of dollars in each HCY. Shoring up these capacity shortfalls in the MISO region will cost an additional $246 billion, which is an annual cost of $7.7 billion. This figure outweighs the estimated net benefits EPA is modeling for the entire country in just one RTO.

EPA does not appear to have the expertise necessary to enact such a sweeping regulation on the American power sector. The most glaring shortcoming of EPA's rulemaking was the agency's failure to conduct a RA or reliability analysis of the modeled MISO grid in the Updated Baseline with LNG Update and failing to model the reliability of its Integrated Proposal with LNG Update. By neglecting these analyses, EPA has mandated major changes to the U.S. electric grid without examining the foundation upon which the new regulations are based.

Because EPA's modeled generation mix cannot prevent blackouts while hindcasting observed historical conditions, we should have no confidence in its assurances that it will have no impact on electric reliability in the future.

American Experiment has noted a series of recommendations that would make EPA's analysis of these regulations more robust. These recommendations can be seen below.

Recommendations

American Experiment's modeling has identified several serious shortcomings in EPA's modeling in the MISO region, and these mistakes were likely made throughout the country in the IPM. Given the severity of the rolling blackouts and the cost of building enough capacity to avert them, EPA should be required to redo their modeling for the proposed Section 111 rules with the following changes to their assumptions.

Increase the Transparency and Responsiveness of EPA: Center of the American Experiment made multiple requests for additional data from powersectormodeling@epa.gov on July 17th and again on August 2nd, but we never received a response acknowledging our request for additional data. The email has been reproduced below:

Hello,

I am requesting additional information from the IPM for the Updated Baseline with Integrated Proposal with LNG Update and the Integrated Proposal with the LNG Update model runs.

- What are the agency's expected capacities, measured in MW, of load-modifying resources (LMRs) or other demand-side resources in each of the model year. This must include each subregion modeled (eg MIS_IA, MIS_IL).
- What are the agency's expected import/export resources, measured in MW in each of the model years? This must include each subregion modeled (eg MIS_IA, MIS_IL).
- What is the hourly electricity generation profile used by EPA to conduct a reliability analysis of the modeled power grid under the proposed rules. This must include each subregion modeled (eg MIS_IA, MIS_IL).

Thank you in advance for providing this information in a timely manner.

Isaac

Isaac Orr
Policy Fellow
Energy and Environmental Policy
Center of the American Experiment

EPA must be transparent in its rulemaking process if the public is to have confidence that these regulations will maintain grid reliability.

Reduce the Accredited Capacity Value of the Thermal Fleet: EPA is overestimating the capacity value of thermal resources on the existing grid by using a 100 percent accreditation. These values should be reduced to reflect real-world conditions, which typically range from 85 to 95 percent of the nameplate capacity of the thermal resource.

Hourly Modeling is Required: EPA should be required to produce hourly load shapes and hourly wind and solar capacity factors for all regions of the country to ensure they are meeting electricity demand at all hours of the year. These load shapes and wind and solar capacity factors should be provided via Microsoft Excel spreadsheets for the public to inspect.

Transmission Mileage Disclosure: EPA should be required to disclose the number of line miles and capacity of transmission used in their modeling assumptions and the years these assets enter service via Microsoft Excel spreadsheets for the public to inspect.

Use HDC Accreditation for Wind and Solar Resources: Current capacity accreditations for wind and solar, both new and existing, are too high. Using net-peak HCD methodology would result in superior capacity accreditation values for EPA's modeling.

Calculate the Total Cost of the Regulations: The IRA subsidies do not reduce the cost of compliance with the proposed Section 111 rules, they simply change who pays for these costs. By not accounting for the cost to taxpayers, EPA is not fully calculating the cost of its rules.

Extend the Public Comment Deadline: EPA's homework on this regulation appears rushed, and the result is an analysis that is less reliable than advertised and more expensive. EPA should extend the public comment period by at least 120 days so further analysis of their IPM output figures can be examined to develop a reliability and cost analysis for a greater share of the country.

APPENDIX

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 Section 111 rules from 2024 through 2055 to capture the long-term cost of the regulations and to compare these costs to those generated by EPA.

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 2055.

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. [13]

These inputs were entered into the model to assess hourly load shapes, capacity shortfalls, and calculate storage capacity needs.

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

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 43.7 percent and 25.5 percent, respectively. This is a generous assumption 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 43.7 percent (See Figure 16).[14]

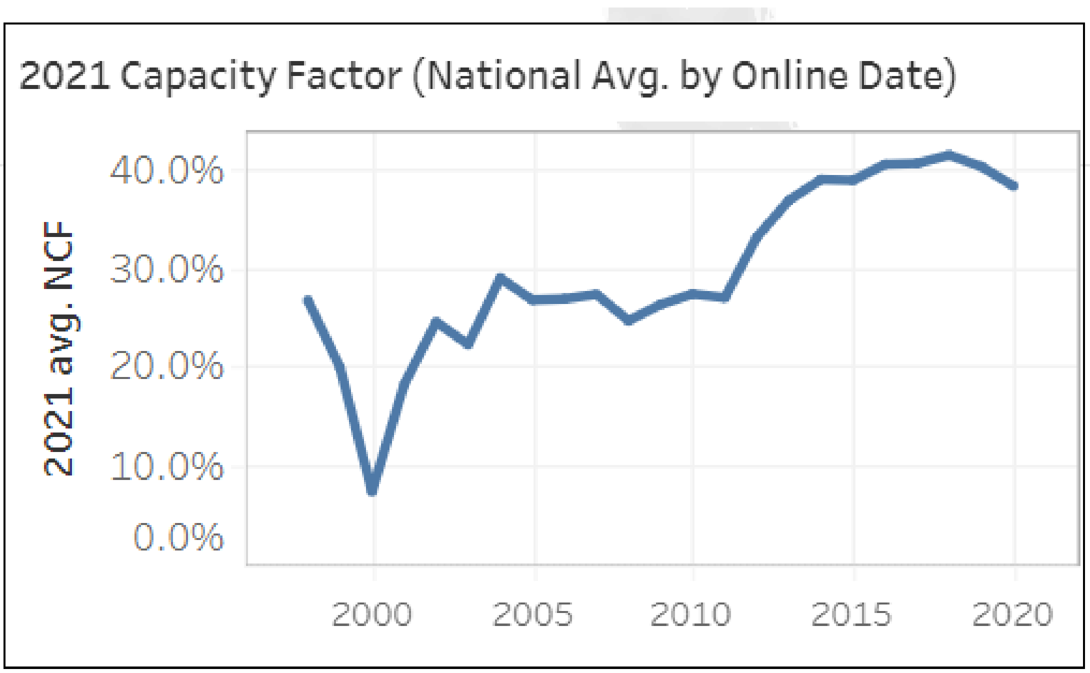


Figure 16. This figure shows capacity factors for U.S. onshore wind turbines by the year they entered service. In no year do these turbines reach EPA's assumed 43.7 percent capacity factor on an annual basis.

Combined cycle natural gas (natural gas CC) plants are assumed to operate below 49 percent capacity factors, thus allowing these plants to avoid using carbon capture and sequestration or co-firing with hydrogen. In our modeling natural gas CC plants operate far below this threshold, running 22.5 percent of the time by 2055, to meet EPA's modeled emissions targets. Natural gas combustion turbine (CT) plants operate at 0.7 percent capacity factors, in line with EPA's assumptions for these resources.

Line Losses

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

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.[15]

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.

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.[16]

Plant retirement schedules

Our modeling does not make decisions about which individual plants will retire due to the proposed Section 111 rules. Rather, coal, natural gas, and nuclear plant capacity is retired to match the changes modeled by EPA in the Integrated Proposal with LNG Update.

Plant construction by type

The resource adequacy and reliability portions of this analysis use EPA's modeled capacity assumptions for the MISO region from the IPM. The cost portion of this analysis assumes new generating resources will be added in rough proportion to EPA's capacity addition estimates in the Integrated Proposal with LNG Update, prioritizing wind, solar, battery storage, and combustion turbine natural gas plants and excluding new nuclear power plants.

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 Section 111 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

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[15] 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

[16] 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.

This analysis assumes the transmission capacity on the MISO system will need to increase by 27,354 miles, constituting a 40 percent increase in the amount of transmission installed in MISO's U.S. footprint.

According to MISO's Renewable Integration Impact Analysis (RIIA) study, most of the required increases in transmission capacity would occur in high voltage transmission lines, meaning those over 230 kilovolts (kV), with the largest increases needed for lines over 345 kV.[17]

MISO has approximately 68,000 circuit-miles of transferred functional control transmission lines serving as the backbone of the footprint (Figure 17) in the United States, with approximately 10,409-line miles of 230 kV transmission lines, 12,435-line miles of 345 kV, 2,250-line miles of 500 kV, and 148-line miles of 765 kV.[18]

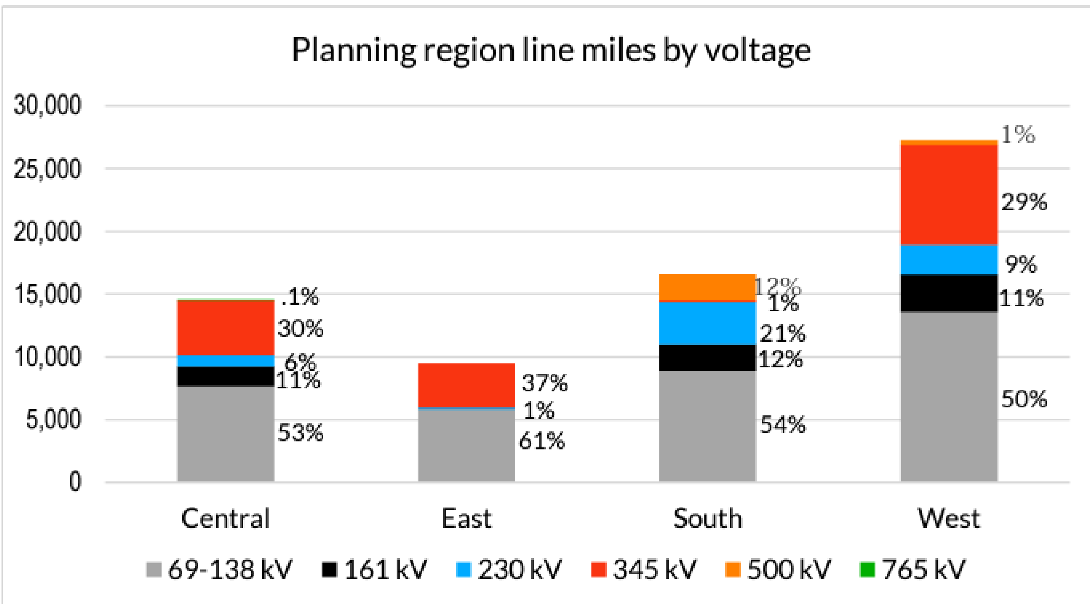

Figure 17. MISO has approximately 68,000 miles of transmission lines in its U.S. footprint. The values for specific line voltages represent the authors' best interpretation of the figure.

In its Electricity Futures Study, the National Renewable Energy Laboratory suggests grids powered by 85 percent wind, solar, and battery storage resources will require additional transmission buildouts of 85.6 percent.[19] This study increases the number of line miles for transmission lines of 230 kV and higher by 85.6 percent.

[17] Midcontinent Independent Systems Operator, "Renewable Integration Impact Analysis," Summary Report, February 2021, https://www.misoenergy.org/planning/policy-studies/Renewable-integration-impact-assessment/.
[18] Line miles are estimated based on the author's best interpretation of Figure 1.1-4 in the Midcontinent Independent Systems Operator, "MISO Transmission Expansion Plan 2022," Accessed July 27, 2023, https://cdn.misoenergy.org/MTEP22%20Chapter%201%20-%20MTEP%20Overview627346.pdf.
[19] National Renewable Energy Laboratory, "Renewable Electricity Futures Study: Executive Summary," U.S Department of Energy, 2012, https://www.nrel.gov/docs/ fy13osti/52409-ES.pdf.

This buildout of transmission lines is estimated to cost $102.9 billion. Costs were calculated using the distance per mile costs from the 2021 Midcontinent Independent Systems Operator Transmission Cost Estimation Guide.[20] We assume all transmission expenses are paid by MISO ratepayers.

These transmission buildouts are consistent with, and more conservative than, the estimated transmission needs in the Net-Zero America study Reference Case, which suggests the nation will need to expand transmission capacity by 47 percent at a cost of $954 billion.[21]

Interconnection costs were estimated to be approximately $48,000 per MW of wind or solar installed, the average cost of active projects at the point of interconnect.[22]

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 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. Coal 45-Q Subsidy of $85 per ton CO2 sequestered.

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.[23] However, our study does not take wind or solar degradation into account.

Capital costs, and fixed and variable operation and maintenance costs

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[20] Midcontinent Independent Systems Operator, "Transmission Cost Estimation Guide for MTEP21," April 27, 2021, https://bit. ly/3AZu59l.
[21] Andrew Pascale et al., "Princeton's Net-Zero America study Annex F: Integrated Transmission Line Mapping and Costing," Princeton University, August 1, 2021, https://netzeroamerica.princeton.edu/img/NZA%20Annex%20F%20-%20HV%20Transmission.pdf.
[22] Lawrence Berkeley Labs, "Data from MISO Show Rapidly Growing Interconnection Costs," Electricity Markets and Policy, October 7, 2022, https://emp.lbl.gov/news/data-miso-show-rapidly-growing.
[23] 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/.

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.[24]

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 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.[25,26] Fuel prices for new natural gas power plants were estimated by averaging annual fuel costs within the MISO region according to EPA.[27] 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.

Carbon Capture and Sequestration projects receive the 45Q subsidies of $85 per ton of carbon dioxide sequestered.

[24] 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.
[25] https://tradingeconomics.com/commodity/natural-gas
[26] https://data.nasdaq.com/data/EIA/COAL-us-coal-prices-by-region
[27] https://www.eia.gov/opendata/v1/qb.php?category=40694&sdid=SEDS.NUEGD.WI.A