Enclosure

The EPA's Basis for Denying, in Part or Whole, Petitions for Reconsideration of 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

The Environmental Protection Agency (EPA) is denying, in part or whole, two petitions from Mountain State Energy Holdings, LLC (MSEH) and Edison Electric Institute (EEI) for rulemaking and reconsideration of 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.[1] This decision document sets forth the basis for this action.

On May 9, 2024, pursuant to section 111 of the Clean Air Act (CAA), the EPA published the Final Rules titled "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" ("Carbon Pollution Standards" or "Final Rules" or "Rules").[2] Following publication of the Final Rules, the Administrator received several petitions for rulemaking and reconsideration of certain provisions of the Final Rules.

The EPA carefully reviewed and evaluated each of these issues raised in the petitions for reconsideration based on the CAA section 307(d)(7)(B) criteria for reconsideration, as well as under section 553(e) of the Administrative Procedure Act (APA). For the reasons explained below, the EPA is denying, in part or whole, the petitions for reconsideration from MSEH and EEI, specifically the objections raised regarding EPA's treatment of grid reliability, the EPA's consideration of financing for new baseload natural gas-fired electric generation units (EGUs), and the inclusion of an enforceable backstop emission rate in conjunction with mass-based compliance flexibilities. EEI's petition also noted two technical corrections needed to the regulatory text for Subpart TTTTa of Part 60. The EPA explains that this document should be viewed as making these corrections and that revisions to the regulatory text to incorporate these minor corrections would be ministerial.

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[1] The EPA received a third petition for reconsideration from the Environmental Defense Fund and Sierra Club. At this time, the EPA is not addressing this petition.
[2] 89 FR 39798.

I. Summary of Petitions for Reconsideration

Following publication of these Final Rules, the Administrator received petitions for reconsideration of certain aspects of the Final Rules pursuant to the Administrative Procedure Act and Clean Air Act.[3]

A. Mountain State Energy Holdings, LLC Petition

On July 30, 2024, MSEH submitted a petition for rulemaking and reconsideration on behalf of its subsidiary Mountain State Clean Energy, LLC.[4] MSEH submitted this petition pursuant to APA section 553(e) and, alternatively, CAA section 307(d)(7)(B). MSEH asserted that new information has arisen in four areas that warrants reconsideration of the Final Rules and called for the EPA to repeal or amend the Final Rules.

First, MSEH stated that the EPA's failure to conduct a grid reliability study in the development of the Final Rules undermines its determination that the Final Rules will not interfere with reliability. To this end, it alleged that the EPA's analysis of annualized resource adequacy, rather than an hourly or daily grid reliability study, cannot answer the question of whether electricity supplies will meet demand every hour of the day. MSEH provided its own grid study and analysis, which it claimed shows the shortcomings of the EPA's approach and conclusions.

Second, MSEH stated that regional power authorities have begun to develop Federal Energy Regulatory Commission (FERC)-approved accreditation protocols that are significantly more conservative than the EPA's estimates, and that this casts doubt on EPA's resource adequacy analysis.

Third, MSEH claimed that the EPA's own modeling of the grid indicates the Final Rules will lead to significant power outages and noted that rising demand will make these outages much worse. MSEH stated that "all regional power authorities have raised their long-term electricity demand forecasts, due to increases in domestic manufacturing, data centers, artificial intelligence processing centers, electric vehicles, and other factors." In particular, MSEH cited PJM's 2024 Load Forecast, which projects that more than half of all energy resources will need to be new construction. MSEH stated that this is particularly problematic because the Final Rules establish a 40 percent baseload threshold for new natural gas-fired EGUs.

Finally, MSEH stated that the Final Rules apply to more base load combustion turbines than EPA anticipated and requires earlier compliance than the proposed form of the Rules, exacerbating reliability concerns. MSEH also asserted that the EPA did not propose or request comment on a shorter compliance deadline, which warrants reconsideration. MSEH additionally claimed that the changes to the Final Rules have made financing for constructing new natural gas

[3] MSEH cited both the APA and CAA as bases for reconsideration; EEI did not cite any specific reconsideration authority.
[4] Mountain State Energy Holdings, LLC's Petition for Rulemaking and Reconsideration, July 30, 2024. Available in Docket ID No. EPA-HQ-OAR-2023-0072.

combined cycle (NGCC) units impossible, although MSEH did not raise this as an issue that merited reconsideration.

MSEH requested that the EPA reconsider the Final Rules and re-propose standards for natural gas-fired combustion turbines that have been permitted but not yet constructed.

B. Edison Electric Institute Petition

On November 4, 2024, EEI submitted a petition for reconsideration of discrete technical provisions of the Final Rules. EEI argued that the EPA's requirement for a backstop emission rate in conjunction with a mass-based compliance approach for existing units was not proposed and the EPA would benefit from additional comment on the issue. In particular, EEI states, "[o]ne specific issue with the inclusion of a backstop rate is that units that are adopting mass-based limitations in state plans would have to comply with both the mass-based and rate-based approach despite foreseeable situations that these two could conflict with one another—*e.g.*, a unit could comply with a mass-based limitation by significantly lowering its utilization or running during specific times, but such utilization would degrade the unit's efficiency in terms of rate-based emissions performance since rate-based measurements decrease from increased unit operation, which results in an increase in actual tons emitted by the unit in operation. EPA should seek to avoid such an approach and outcome."

EEI requested that the EPA issue guidance directly to the states for purposes of state plan development that explicitly provides that the EPA will not require a backstop rate for exiting units that are complying with mass- or rate-based compliance approaches.

EEI's petition also noted two technical corrections needed to the regulatory text for Subpart TTTTa of Part 60, specifically Equation 3 of section 60.5225a and Table 1.

II. Legal Framework for Review of Petitions

The two petitions at issue in this denial are framed as petitions for reconsideration and rulemaking, citing various statutory provisions. Specifically, MSEH styled its petition as a request for reconsideration and rulemaking, citing both CAA section 307(d)(7)(B) and APA section 553(e).[5] EEI's request is framed as a request for reconsideration, although it did not cite any specific authority. Given the ambiguities and inconsistencies in the Petitioners' legal claims, the EPA reserves its right to argue on judicial review that each Petitioner has failed to adequately invoke the proper legal authority for its petition. Nevertheless, the EPA has analyzed each petition under the standard for reconsideration under CAA 307(d)(7)(B) and determined that neither petition meets the statutory criteria for mandatory reconsideration set forth in CAA section 307(d)(7)(B). This conclusion alone supports denial of these petitions, insofar as they seek reconsideration under CAA section 307(d)(7)(B). However, for purposes of this decision, the EPA is also evaluating these petitions as APA petitions for rulemaking to reopen or revise the Final Rules. Ultimately, as explained in section III of this final action, the EPA is denying or

[5] Petitioner MSEH also cited section 705 of the APA, but did not present any argument for a stay on that basis. The EPA is therefore not addressing APA section 705 in this denial document.

partially denying both petitions because they fail to meet the statutory criteria for mandatory reconsideration under CAA section 307(d)(7)(B) and fail to identify any other compelling basis for reopening or revising the Final Rules under the CAA or the APA. The remainder of this section will provide an overview of the relevant legal frameworks for the EPA's decision.

A. CAA 307(d)(7)(B)

Under section 307(d)(7)(B) of the CAA, "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment … may be raised during judicial review."[6] In addition, "[i]f a person raising an objection can demonstrate … that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule, the Administrator shall convene a proceeding for reconsideration of the rule." *Id.* Thus, the EPA is required to convene a reconsideration proceeding only if the Petitioner demonstrates to the EPA both: (1) that it was impracticable to raise the objection during the comment period, or that the grounds for such objection arose after the comment period but within the time specified for judicial review (*i.e.*, within 60 days after publication of the final rulemaking notice in the Federal Register, see CAA section 307(b)(1)); and (2) that the objection is of central relevance to the outcome of the rule. CAA section 307(d)(7)(B).

1. Prong One: Adequate Notice and Logical Outgrowth

In practice, and pursuant to established precedent, in evaluating the first prong of CAA section 307(d)(7)(B) (whether petitioners can demonstrate that it was impracticable to raise an objection within the period for judicial review or that the grounds for the objection arose after the period for public comment but within the time specified for judicial review) courts consider whether the final rule so deviated from the proposal that petitioners were unable to adequately comment on the rule during the public comment period. In other words, the test under the first prong of CAA section 307(d)(7)(B) is whether the final rule contains changes or elements that were completely new and unknown or unable to be known and therefore could not have been commented upon during the comment period. Thus, the EPA, in reviewing such petitions under CAA section 307(d)(7)(B), is first called upon to consider whether the contents of the Final Rules were properly and adequately noticed to the public.

The D.C. Circuit has made clear that "EPA undoubtedly has authority to promulgate a final rule that differs in some particulars from its proposed rule."[7] If that were not the case, the purpose of notice and comment—to allow an Agency to reconsider, and perhaps revise, a proposed rule based on the comments submitted—would be undermined and agencies could either be "forced into perpetual cycles of new notice and comment periods," or "refuse to make changes in

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[6] The requirements of CAA section 307(d)(7)(B) apply to rules promulgated under CAA section 307(d). The Carbon Pollution Standards is such a rule. See CAA section 307(d)(1)(C), 89 FR 39807.

[7] *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 546 (D.C. Cir. 1983).

response to comments."[8] Thus, when considering the adequacy of notice and comment under both the APA and CAA section 307(d), courts ask whether the final rule is a "logical outgrowth" of the proposal.[9]

The logical outgrowth test is a fact-intensive, case-by-case inquiry that requires balancing the purposes of public notice—improving rulemaking by "exposure to diverse public comment," ensuring "fairness to affected parties" and "develop[ing] evidence in the record"—against the "public interest in expedition and finality."[10] "Whether the logical outgrowth test is satisfied depends on whether the affected party 'should have anticipated' the Agency's final course in light of the initial notice."[11] Notably, courts have found a final rule to be a logical outgrowth of the proposal where "at least the 'germ' of the outcome is found in the original proposal."[12] This includes not only instances where an Agency "expressly ask[ed] for comments on a particular issue or otherwise ma[de] clear that the agency [was] contemplating a particular change;"[13] but also where a new provision was "adequately foreshadowed" by a proposal discussing the importance of an issue that the new provision addressed.[14]

2. Prong Two: Central Relevance

Per D.C. Circuit precedent, an objection is of "central relevance" to the outcome of a rule "if it provides substantial support for the argument that the regulation should be revised."[15] Thus, an objection is of central relevance to the outcome of the rule if, based on the merit of that objection, the EPA would have reached a different outcome in the rulemaking. In other words, in order to satisfy the central relevance prong, Petitioners must demonstrate that had the EPA had the information at issue before it when developing its rulemaking, the Agency would have reached a different outcome.

Moreover, the D.C. Circuit precedent holds that should the EPA deny a petition for reconsideration, "EPA certainly may … provide an explanation for that denial, including by providing support for that decision, without triggering a new round of notice and comment for the rule."[16]

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[8] *Ass'n of Battery Recyclers, Inc. v. EPA*, 208 F.3d 1047, 1058 (D.C. Cir. 2000).
[9] *Small Refiner*, 705 F.2d at 546.
[10] *Id.* at 547; *see Nat'l Min. Ass'n v. Mine Safety & Health Admin.*, 116 F.3d 520, 531 (D.C. Cir. 1997) ("Our cases offer no precise definition of what counts as a "logical outgrowth").
[11] *Agape Church v. FCC*, 738 F.3d 397, 412 (D.C. Cir. 2013).
[12] *NRDC v. Thomas*, 838 F.2d 1224, 1242, 1242 (D.C. Cir. 1988).
[13] *United States Telecom Ass'n v. FCC*, 825 F.3d 674, 700 (D.C. Cir. 2016),
[14] *Health Insurance Ass'n of America v. Shalala*, 23 F.3d 412, 421 (D.C. Cir. 1994).
[15] See *Coal. For Responsible Regulation, Inc. v. EPA*, 684 F.3d 102, 125 (D.C. Cir. 2012) (internal citation and quotation omitted).
[16] *Coalition for Responsible Regulation*, 684 F. 3d at 126.

B. APA 553(e)

Section 553(e) of the APA requires that "[e]ach agency shall give an interested person the right to petition for the issuance, amendment, or repeal of a rule."[17] Additionally, APA section 555(e) provides that in addition to "prompt notice," any denial of such application must include a "brief statement of the grounds" for that denial "except when affirming a prior denial or where the denial is self-explanatory."[18]

The D.C. Circuit has stated that considering APA section 553(e) and 555(e) in tandem, "[t]hese two provisions suggest that Congress expected that agencies denying rulemaking petitions must explain their actions".[19] Courts review denials of petitions for rulemaking, and refusals to initiate a new rulemaking, under the arbitrary and capricious standard.[20] That said, the D.C. Circuit has characterized arbitrary and capricious review as encompassing a range of levels of deference to the agency, with refusals to initiate a rulemaking being entitled to a high degree of deference.[21] The Supreme Court has also indicated that judicial review of refusals to promulgate rules is "extremely limited" and "highly deferential".[22] In reviewing petition denials, courts "ask whether the agency employed reasoned decisionmaking in rejecting the petition" and "overturn the agency's decision only for compelling cause, such as plain error of law or a fundamental change in the factual premises previously considered by the agency."[23]

III. Evaluation of the Petitions for Reconsideration

A. Reliability

Petitioner MSEH made a series of arguments in its petition for reconsideration regarding EPA's consideration of reliability issues, none of which merit a change to the Final Rules or satisfy the standard for reconsideration under CAA section 307(d)(7)(B). As a general matter, Petitioner argued that the Final Rules endanger grid reliability and will lead to outage events. In defense of this point, Petitioner argued first that the EPA's resource adequacy modeling was inadequate, and that the EPA failed to appropriately consider reliability.[24] Second, Petitioner argued that the EPA failed to adequately consider the impacts of increased load growth driven by new electricity demands. For the reasons outlined below, the EPA is denying the petition for reconsideration on these issues because Petitioner failed to demonstrate that it was impracticable to raise its objections during the comment period or that the ground for this objection arose after such a period, and because Petitioner failed to demonstrate that any of its objections satisfy the central

[17] 5 U.S.C. 553(e).
[18] 5 U.S.C. 555(e).
[19] *American Horse Protection Ass'n v. Lyng*, 812 F.2d 1, 4 (D.C. Cir. 1987).
[20] *See id.* at 5.
[21] *Flyers Rights Education Fund, Inc. v. FAA*, 864 F.3d 738, 743 (D.C. Cir. 2017).
[22] *Mass. v. EPA*, 549 U.S. 497, 527-28 (2007).
[23] *Id.*
[24] Mountain State Energy Holdings, LLC's Petition for Rulemaking and Reconsideration, July 30, 2024. Available in Docket ID No. EPA-HQ-OAR-2023-0072.

relevance requirement. The EPA thoroughly considered grid reliability, including the specific issues raised in MSEH's petition, in its rulemaking and made multiple changes to its Proposed Rules to create flexibility specifically for reliability purposes. There is nothing in MSEH's petition for reconsideration that would change EPA's conclusion that the Final Rules will not interfere with the maintenance of electric grid reliability.

1. The EPA's Evaluation of Reliability was Appropriate, and Petitioner's Claims Fail to Satisfy the Requirements for Reconsideration

Petitioner claimed that the EPA's modeling was inadequate, and that the Agency failed to properly evaluate reliability. This claim fails on the merits and does not satisfy either prong under CAA 307(d)(7). The EPA analyzed and addressed grid reliability throughout the rulemaking, including by modeling the Final Rules' potential impact on resource adequacy and assessing the implications for grid reliability overall.[25]

a. Petitioner Had Adequate Notice of EPA's Modeling Approach, and the Final Rule Was a Logical Outgrowth of the Proposal

First, Petitioner had ample notice of the EPA's intended modeling approach. In developing the proposed Carbon Pollution Standards,[26] the EPA conducted a comprehensive resource adequacy

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[25] 89 FR 39803, 39886, 40011-20; Resource Adequacy Analysis Technical Support Document for 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 – Proposal ("Resource Adequacy TSD – Proposal"). Document ID No. EPA-HQ-OAR-2023-0072-0034; Resource Adequacy Analysis Technical Support Document for 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 – Final Rule ("Resource Adequacy TSD – Final Rule"). Document ID No. EPA-HQ-OAR-2023-0072-8916; Resource Adequacy Analysis: Vehicle Rules, Final 111 EGU Rules, ELG and MATS RTR. Technical Memo for 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 – Final Rule. Document ID No. EPA-HQ-OAR-2023-0072-8915.

[26] 88 FR 33240 (May 23, 2023), "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: Proposed Rule" ("Proposed Rules" "Proposal" or "proposed Carbon Pollution Standards").

analysis and made this analysis available in the docket for comment.[27] As the EPA stated in the Proposed Rules, the Agency "has evaluated the reliability implications of the proposal in the *Resource Adequacy Analysis* [Technical Support Document]; conducted dispatch modeling of the proposed NSPS and proposed emission guidelines in a manner that takes into account resource adequacy needs; and consulted with the DOE and the Federal Energy Regulatory Commission (FERC) and staff in the development of these proposals. Moreover, the EPA has included in these proposals the flexibility that power companies and grid operators need to enable them to plan for achieving feasible and necessary reductions of [greenhouse gases] from these sources consistent with the EPA's statutory charge while ensuring grid reliability."[28] The EPA also explicitly solicited comment on localized impacts of these Proposed Rules on resource adequacy and reliability, and on opportunities to enhance reliable integration of the Proposals into the power system.[29] Additionally, the Agency met with each and every balancing authority that submitted comment to the docket pertaining to reliability. Further, in November 2023, the EPA participated in FERC's Annual Reliability Technical Conference, which addressed, among other things, the potential impacts of the proposed Carbon Pollution Standards on electric reliability.[30] Testimony presented at this conference, in addition to comments on the Proposed Rules from FERC itself, were incorporated into the record and considered as part of the rulemaking process. The EPA also issued a Supplemental Proposal which focused on reliability implications of the proposed Carbon Pollution Standards, and specifically solicited comment on ways to address grid reliability needs.[31] The EPA subsequently adjusted the Final Rules in response to the input received to create flexibility in areas for which stakeholders had identified and substantiated reliability concerns.[32]

In its comments on the Proposed Rules, Petitioner MSEH, among other parties, raised concerns about the impact of the Carbon Pollution Standards on grid reliability.[33] The EPA responded to these and other comments on this issue in section XII.F of the preamble to the Final Rules, "Grid Reliability Considerations and Reliability-Related Mechanisms"[34] and chapter 16.3 of the

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[27] U.S. EPA, Analysis of the Proposed Greenhouse Gas Standards and Guidelines, Power Sector Modeling, *https://www.epa.gov/power-sector-modeling/analysis-proposed-greenhouse-gas-standards-and-guidelines;* U.S. EPA, Regulatory Impact Analysis, Section 3.5 EPA's Power Sector Modeling of the Baseline Run and Three Illustrative Scenarios, Document ID No. EPA-HQ-OAR-2023-0072-0007; U.S. EPA. RIA Section 3 - Cost Emissions and Energy Impacts, Document ID No. EPA-HQ-OAR-2023-0072-0056.
[28] 88 FR 33246-47.
[29] 88 FR 33247.
[30] See FERC Technical Conferences, "2023 Annual Reliability Technical Conference," *https://www.ferc.gov/news-events/events/2023-annual-reliability-technical-conference-11092023*.
[31] 88 FR 80682.
[32] See 89 FR 40011-20.
[33] Comment submitted by Mountain State Energy Holdings, LLC. August 8, 2023, Document ID No. EPA-HQ-OAR-2023-0072-0829.
[34] 89 FR 40011-20.

Response to Comments Document, "Grid Reliability and Resource Adequacy."[35] Petitioner did not raise concerns about EPA's power sector modeling in its comments on the Proposed Rules. However, the EPA received numerous comments on its modeling from parties other than Petitioner MSEH, which the Agency summarized and responded to in chapter 14.2 of the Response to Comments Document, "Modeling of Illustrative Policy Scenarios in [the Integrated Planning Model]".[36] Petitioner fails to demonstrate that it was impracticable to raise its objections to the EPA's focus on resource adequacy or to the Agency's modeling approach during the comment period, or that the grounds for these objections arose after this period; on the contrary, as shown here, these issues were raised and responded to during the rulemaking.

b. Petitioner's Claims Regarding EPA's Modeling are Not of Central Relevance to the Outcome of the Rule

Second, Petitioner's claim fails the central relevance prong because it has failed to show that the EPA would have reached a different outcome had the Petitioner's objections to the Agency's modeling been raised during the rulemaking. The EPA addressed the issues raised in MSEH's petition on their merits in the Final Rules and explained that, and why, its modeling approach to considering resource adequacy was a reasonable and appropriate manner of assessing impacts on grid reliability.

1) Resource Adequacy Versus Operational Reliability

Electric grid reliability is comprised of multiple components; while different entities may define these components slightly differently, they follow generally similar lines. FERC has explained that electric grid reliability is based on two elements: resource adequacy and reliable operation (*i.e.*, operational reliability).[37] Resource adequacy, according to FERC, "is the ability of the electric system to meet the energy needs of electricity consumers. This means having sufficient generation to meet projected electric demand."[38] Reliable operation is satisfied when an electric grid "has the ability to withstand sudden electric system disturbances that can lead to blackouts."[39] The National Renewable Energy Laboratory (NREL) refers to three elements of grid reliability: resource adequacy, operational reliability, and resilience. NREL explains that "[r]esource adequacy is defined by [the North American Electric Reliability Corporation (NERC)] as 'the ability of the electricity system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and

[35] U.S. EPA, Response to Comments Document, April 2024, Document ID No. EPA-HQ-OAR-2023-0072-8914.
[36] *Id.*
[37] Federal Energy Regulatory Commission, Reliability Explainer, August 16, 2023, *https://www.ferc.gov/reliability-explainer*.
[38] *Id.*
[39] *Id.*

reasonably expected unscheduled outages of system elements.'"[40] NREL further notes that NERC defines operational reliability "as 'the ability of the Bulk-Power System to withstand sudden disturbances, such as electric short circuits or the unanticipated loss of system elements from credible contingencies, while avoiding uncontrolled cascading blackouts or damage to equipment.'"[41,42] In its Resource Adequacy Analysis Technical Support Document (TSD) accompanying the Proposed Rules, the EPA stated that, as used in that analysis, "resource adequacy is defined as the provision of adequate generation resources to meet projected load and generating reserve requirements in each power region, while reliability includes the ability to deliver resources to the loads, such that the overall power grid remains stable."[43]

The EPA focused its modeling on resource adequacy as that is the aspect of grid reliability most proximately impacted by the Rules. As explained in the Resource Adequacy Analysis TSD for the Final Rules, "[t]he objective of this analysis is to provide insight into the resource adequacy impacts of the rule. EPA's role in regulating emissions from electric generating units does not include specifying generation resource mixes or grid operations and planning practices. Thus, EPA does not conduct operational reliability studies."[44]

The Rules contain requirements for emissions of carbon dioxide that will factor into states', utilities', and grid operators' long-term plans for the types and amounts of generation and capacity that will exist in the future. The Rules do not, however, specify or require particular generation mixes or grid operations and planning practices. For example, the Rules do not

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[40] National Renewable Energy Laboratory, "Explained: Fundamentals of Power Grid Reliability and Clean Electricity" at 2, NREL/FS-6A40-85880, Jan. 2024, *https://www.nrel.gov/docs/fy24osti/85880.*pdf.

[41] *Id.*

[42] NREL explains that the third component of grid reliability, resilience, "is less well-defined than [resource adequacy and operational reliability]," and that FERC "defines resilience as 'the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.'" *Id.*at 3. Petitioner MSEH did not raise resilience in its petition; however, it is important to note that disruptive events often take the form of severe weather, which is being exacerbated by climate change, the very issue that the Carbon Pollution Standards were promulgated to address.

[43] Resource Adequacy Analysis Technical Support Document for 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 – Proposal ("Resource Adequacy TSD – Proposal") at 2, Document ID No. EPA-HQ-OAR-2023-0072-0034; see also Resource Adequacy Analysis Technical Support Document for 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 – Final Rule ("Resource Adequacy TSD – Final Rule") at 2, Document ID No. EPA-HQ-OAR-2023-0072-8916.

[44] Resource Adequacy TSD – Final Rule at 2.

purport to regulate electricity transmission or require that grids maintain a certain level of essential reliability services. Decisions on these and other aspects of operational reliability are within the purview of states, utilities, and grid operators.[45] These entities have a multitude of tools to address operational reliability, many of which are not impacted by the Rules. Because the Carbon Pollution Standards generally impact decisions about what types of generators power companies may choose to build or retire (components of resource adequacy) and not on operation of generators in real time (except in that they are required to meet emission limitations), the EPA focuses its reliability analysis on resource adequacy and not on operational reliability.

NREL notes that "the concepts of resource adequacy and operational reliability do overlap occasionally, but in general, resource adequacy focuses on having enough generators and transmission available to meet demand, and operational reliability focuses on how those generators are operated in real time."[46] While the development of plans for operational reliability will certainly be informed by decisions these parties make about how to comply with the Rules, the EPA cannot know what the grid will look like with the certainty necessary to make an operational reliability modeling exercise predictive of the actual impacts of its Rules. The EPA did not, and did not intend to, predict what the grid will look like in the future. Moreover, the Final Rules do not tell grid operators what portfolio to select: rather, the Agency used the best available long-term capacity expansion framework to illustrate possible compliant portfolios and contextualize them via an energy requirements analysis. As explained in a third-party expert's analysis of the EPA's modeling approach for the proposed Carbon Pollution Standards:

> Resource adequacy considerations indeed differ from operational reliability ones, but EPA has not erred in modeling only the former. It is not reasonable to expect that at this point in time EPA should have modeled operational-reliability outcomes for the nation – that is, prior to actual promulgation of standards that (a) require state implementation plans to be developed, (b) require compliance obligations no earlier than 2030, and (c) allow for flexibility in owners' decisions about how to comply with the eventual standards and [State Implementation Plans] . . . . It would be unrealistic to expect that EPA (or even anyone with operational responsibility for the grid) to know the specific future compliance decisions of power plant owners that would be required to conduct meaningful detailed system

[45] See, *e.g.*, Energy Innovation Policy and Technology, LLC, Maintaining a Reliable Grid Under EPA's Proposed 111 Rules Restricting Power Plant Emissions at 24-29 (explaining that "a multitude of different actors including utilities, regulatory, and system operators are each partly responsible" for "[m]anaging the clean energy transition to ensure reliability and affordability" and outlining six recommendations these entities can take to this end). *https://energyinnovation.org/wp-content/uploads/Maintaining-a-Reliable-Grid-Under-EPAs-Proposed-111-Rules.pdf*.

[46] National Renewable Energy Laboratory, "Explained: Fundamentals of Power Grid Reliability and Clean Electricity" at 2-3. *https://www.nrel.gov/docs/fy24osti/85880.pdf*.

> impact studies across all regions of the country affected by the new standards starting nearly a decade from now."[47]

It is important to note that the reported solution from the EPA's Integrated Planning Model (IPM) analysis—the particular mix of capacity and generation that IPM identified as one possible approach under the Final Rules— is not the only way to comply with those Rules.[48] Regulated entities may respond to the Final Rules' requirements in a wide variety of ways. Of the billions of possible solutions to the constraints imposed on the model, the reported solution minimizes the present value of the production cost over the forecast horizon. However, regulated entities are not bound to any one solution. Entities may choose, instead, to respond by greater installation of the cost-effective controls that the EPA determined to be BSER, or through a different mix of strategies and resources. Indeed, the Rules are designed to provide significant flexibility in order to facilitate these types of decisions, and grid operators and reliability organizations with deep expertise in their own systems will be able to avail themselves of these flexibilities in order to ensure operational reliability is maintained.

Moreover, the Final Rules allow for optional flexibilities for existing sources such as emissions averaging and trading[49] as well as source-specific variances that can be used under certain circumstances to accommodate grid reliability considerations[50] when designing a compliance strategy. These flexibilities may be important tools for states and reliability authorities to use in addressing operational reliability. For example, the Final Rules provide a mechanism to make it easier for sources that had planned to permanently cease operation to extend their retirement dates by up to one year if needed to prevent a risk to reliable grid operation.[51] However, because the EPA cannot predict what flexibilities or strategies states will choose to adopt in the future, it did not incorporate any use of these flexibilities in its projections; given that pertinent decisions have not yet been made, any modeling the EPA could conduct at this point in time would provide little, if any, meaningful information about operational reliability under implementation of the Final Rules.

For these reasons, EPA's focus on modeling resource adequacy is an appropriate approach for examining the impacts of power sector policies on generation and capacity in the mid- to long-term.[52] The Agency's resource adequacy modeling demonstrates that there are clear paths to

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[47] Susan Tierney, Analysis Group, "Electric System Reliability and EPA Regulation of GHG Emissions from Power Plants: 2023" at 35, November 7, 2023, *https://www.analysisgroup.com/globalassets/insights/publishing/2023-tierney-electric-reliability-and-epa-ghg-regs.pdf.*

[48] An in-depth discussion of the EPA's IPM modeling is provided in section III.A.1.b.ii of this document.

[49] 40 CFR 60.5775b(e).

[50] See, *e.g.*, 40 CFR 60.5775b(j).

[51] 40 CFR 60.5740b(a)(13).

[52] U.S. Department of Energy, "Power Sector Modeling 101" at 10-13, *https://www.energy.gov/sites/prod/files/2016/02/f30/EPSA_Power_Sector_Modeling_FINAL_02*

compliance with the Final Rules that respect reliability constraints, without dictating to states and reliability authorities the precise routes they must follow. Moreover, the modeling includes constraints that approximate some of the considerations associated with operational reliability—*i.e.* the decisions that ensure availability of energy from minute to minute within the power sector—as detailed in the following section of this document. However, the model does not perform an operational reliability exercise, since this would be the responsibility of various grid operators that necessarily have a deeper understanding of their networks and can ensure that the Final Rules-compliant portfolio is able to produce operational reliability attributes consistent with their planning parameters. The EPA's role is not to address every contingency or potential disturbance to the grid, but rather to ensure that the Final Rules create the conditions for resource adequacy under which states, utilities, and grid operators then take actions of their choosing to maintain grid reliability. And, critically, these parties are already developing and deploying the tools and strategies necessary to do so, as the sector's ongoing transition towards lower GHG-emitting generation resources is well documented.[53]

The Petitioner's assertion that the EPA should have used more granular, time sensitive modeling on a national basis is unfounded. As explained above, this type of modeling would necessarily be based on speculation about states' and utilities' future compliance choices and the utility of such an assessment would be limited at best. Many utilities themselves rely primarily on resource adequacy modeling for their long-term planning and reliability assessment purposes, reinforcing the reasonableness of the EPA taking this approach for its Rules. For example, for purposes of its integrated resource planning, Alabama Power conducts capacity expansion modeling, which is a method of assessing resource adequacy (what the EPA's IPM modeling also does), to test if various portfolios would satisfy a target reserve margin.[54] Similarly, Duke Energy Carolinas develops its portfolio based on a resource adequacy analysis that reflects, like the EPA's modeling (discussed below), the potential impacts of extreme weather and the performance of

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1816_0.pdf (capacity expansion models, of which IPM is one and that examine resource adequacy, can quantify the impacts of environmental policies on generation and capacity).

[53] See, *e.g.*, The Brattle Group, "Bulk System Reliability for Tomorrow's Grid" Section IV (summarizing five key reliability needs; explaining reforms and adaptations grid operators have already introduced to address the shifting resource mix, evolving demand patterns, and growing impact of extreme weather; and highlighting remaining challenges and potential paths forward), *https://www.brattle.com/wp-content/uploads/2023/12/Bulk-System-Reliability-for-Tomorrows-Grid_December-2023_Final.pdf*; Energy Innovation Policy and Technology, LLC, Maintaining a Reliable Grid Under EPA's Proposed 111 Rules Restricting Power Plant Emissions at 19-24 (detailing tools available to maintain grid reliability and providing examples of steps already being taken to maintaining operational reliability for grids without unabated coal). *https://energyinnovation.org/wp-content/uploads/Maintaining-a-Reliable-Grid-Under-EPAs-Proposed-111-Rules.pdf*.

[54] Alabama Power, "2022 Integrated Resource Plan Summary Report" at 13, 21-22, *https://www.alabamapower.com/content/dam/alabama-power/pdfs-docs/company/compliance---regulation/IRP.pdf*.

different resources. The company then conducts an additional analysis to look at whether its chosen portfolio of resources can meet demand in each hour.[55]

2) Overview of EPA's Modeling Approach

As discussed below, and as detailed extensively in the record, the EPA determined, for each subcategory, the best system of emission reduction (BSER) that was based on adequately demonstrated and cost-effective control technology and conducted detailed modeling to examine the energy requirements of the Rules, including their potential impacts on electric grid reliability. The EPA performed this modeling using IPM, a peer reviewed capacity expansion model that has been used by the Agency as well as widely used by industry over multiple decades to evaluate long-term power sector futures.[56]

As noted earlier, the Final Rules are designed to provide significant lead time for adoption of control technologies – for instance, standards of performance reflecting the implementation of 90 percent carbon capture and storage (CCS) on new baseload gas fired combustion turbines do not apply until 2032, and states need not require compliance with 90 percent CCS-based standards for long-term existing coal plants until the same.[57] As such, the Rules are designed to impact emissions of facilities in the long-term, and are evaluated using a capacity expansion framework that is designed to capture the long-term dynamics of the sector.[58]

The IPM model is designed to capture resource adequacy, which is achieved when there is sufficient accredited capacity to meet a peak plus reserve margin target as reported by the North American Electric Reliability Corporation (NERC) within the relevant IPM model regions.[59] The calculation of the accredited capacity is based on the Effective Load Carrying Capability (ELCC) of different types of generation.[60] For intermittent resources, the model is designed to capture the declining ELCC value as a function of penetration as outlined in section 4.4.5 of the IPM documentation – in other words, as more wind and solar penetrates a given region, the contribution of incremental solar and wind additions to meeting the reserve margin target falls

[55] Duke Energy, "2023 Carolinas Resource Plan, Chapter 2" at 2-4, *https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/chapter-2-methodology-and-key-assumptions.pdf?rev=44036eb8cc98429c92e7ac00bea5f445*.
[56] U.S. EPA, RIA Section 3 – Compliance Costs Emissions and Energy Impacts Final - IPM documentation, Chapter 1 – Introduction, Document ID No. EPA-HQ-OAR-2023-0072-8396.
[57] Table 1 to Subpart TTTTa of Part 60, Title 40; 40 CFR 60.5780b(a)(1).
[58] U.S. EPA, RIA Section 3 – Compliance Costs Emissions and Energy Impacts Final - IPM documentation, Chapter 2 – Modeling Framework, Document ID No. EPA-HQ-OAR-2023-0072-8396.
[59] Resource Adequacy TSD – Final Rule at 5-6, Document ID No. EPA-HQ-OAR-2023-0072-8916.
[60] U.S. EPA, RIA Section 3 – Compliance Costs Emissions and Energy Impacts Final - IPM documentation, Chapter 2 – Modeling Framework. Document ID No. EPA-HQ-OAR-2023-0072-8396.

given the changing correlation between their output and the peak hours.[61] The model also uses a similar approach to assign reserve margin contribution to battery storage as a function of penetration. The model tracks the duration of the peak event as a function of the penetration of storage resources, and derates the contribution of storage resources as the duration of the peak event increases. These modeling approaches ensure that the model solves for a portfolio that respects the ability of resources, including intermittent and storage resources, to contribute to meeting peak demand requirements, and mirrors the calculations performed by grid operators when evaluating their systems.

In addition to the capacity constraints outlined above, IPM also incorporates energy constraints to ensure that the demand for electricity across various hours can be met by resources that are available in those various hours. Within the model, the year is divided into four seasons, and each season is divided into six segments, representing the highest demand hours, followed by lower demand hours. Each of these segments is further divided into time-of-day cuts, which isolate the demand hours into four groups based on whether they occur at night, in the morning, the afternoon or the evening.[62]

When modeling intermittent resources, the model is populated with hourly generation profiles that are based on historical weather data developed by NREL. For each model plant, these hourly generation profiles are mapped to the 96 time segments outlined above. In other words, the model keeps track of when a particular solar resource is available and ensures that, for instance, it is not able to produce electricity in any night hours. Similarly, the model accounts for the capacity factor of the resource by season, as well as the correlation between output and the type of demand hour (*i.e.*, the ability of particular intermittent resources is differentiated between the highest demand hours and the lower demand hours, which is key to representing the ability of resources to meet energy demand). Thus, contrary to Petitioner's assertion, the EPA's modeling framework is in fact highly sensitive to the relative accreditation of various intermittent resources, and the model is constrained to ensure that seasonal peak and reserve margin constraints are met. Similarly, the model is populated with turn down constraints that reflect the cycling capabilities of various thermal units (*i.e.*, whether they can be shut down at night or on weekends, must operate at all times, or must operate at least at some minimum capacity level; the constraints ensure that the model reflects the distinct operating characteristics of peaking, cycling, and base-load units) as well as a representation of planned and unplanned outages. The IPM modeling results presented as part of the EPA's Final Rules therefore take into account the ability of that particular portfolio to meet energy demand over the course of the year, accounting for the availability of different units within the solution set, not just during peak events, and does not assume any technology is available 100 percent of the time over the course of a run year.

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[61] U.S. EPA, RIA Section 3 – Compliance Costs Emissions and Energy Impacts Final - IPM documentation, Chapter 4 – Generating Resources, Document ID No. EPA-HQ-OAR-2023-0072-8396.

[62] See generally U.S. EPA, IPM Documentation Chapter 2 – Modeling Framework, Document ID No. EPA-HQ-OAR-2023-0072-8396.

IPM is also populated with a range of constraints based on historical data. For instance, incremental renewable additions are subject to cost escalation constraints that are tied to historical levels of build out – in other words, annual capacity additions through 2035 are consistent with the recent historical trend and the model does not simply rely on unconstrained low-cost builds to satisfy energy demand. A capacity expansion model, in order to reach a feasible solution, must both (1) be able to secure sufficient accredited capacity to meet peak plus reserve margin targets in every period; and (2) be able to meet energy demand across all years, seasons, and segments over the forecast period. The EPA's model does both, and incorporates key features such as time of day cuts within the segment definition, planned and unplanned outages at model plants and the declining reserve margin contribution of renewables and storage as a function of their penetration in order develop a robust portfolio that can meet energy and peak demand requirements. Furthermore, annual build levels are tied to the historical record through 2035 in order to ensure the model reflects real-world constraints. Based on historical build outs, this is likely a conservative assumption. For instance, in the early 2000s, NGCC build outs significantly exceeded historical build rates, in the early 2010s, wind build outs exceeded historical rates and in the early 2020s, solar and storage build outs significantly exceeded historical rates.

The compliant portfolio presented by the EPA is compared to a baseline scenario absent the Final Rules, and the change in total costs between these two solutions is presented. These costs are a reflection of the amount of stress placed on the system; if the costs of a particular scenario are significantly higher than the baseline, it is an indication that the scenario may strain the system. Critically, as outlined in the Regulatory Impact Analysis (RIA), the cost of the Final Rules remains relatively small[63] when compared to the total production cost associated with U.S. electricity production. This is in large part due to the fact that there are pre-existing long-term trends that are reducing thermal generation share, and particularly reducing coal-fired generation share within the U.S. electricity mix. As such, the compliant portfolio reflects a modest acceleration of these trends and not a wholesale change to the power sector. It is further an indication that the incremental changes relative to the baseline scenario that would be needed to ensure continued resource adequacy are not projected to strain the system. In the event that electricity demand is higher than expected, the greater need for electricity would in turn increase the cost-competitiveness of CCS for long-term baseload assets while improving the relative economics for units converting to gas or co-firing gas (which would aid the ability to provide additional ramping capability for coal-fired EGUs).

Further, IPM's methods of modeling different types of technologies, and the outcomes it produces, are a reasonable approach to estimating the potential impacts of the Final Rules on the

[63] As reported in U.S. EPA, RIA Section 3 - Cost Emissions and Energy Impacts, Document ID No. EPA-HQ-OAR-2023-0072-0056, for this rulemaking, the annualized cost of the Final Rules is projected to be 0.47 billion 2019$ (2024-2047, assuming a 3.76% discount rate). Under the baseline the annualized total production cost over this period is projected to be 105.5 billion 2019$ (2024-47, assuming a 3.76% discount rate). Hence the Final Rules reflect a less than 1% increase in annualized total production cost over this analysis period.

grid. Capacity expansion models are designed to show the relative economics of populated technology options. As has been outlined extensively throughout the record for the Carbon Pollution Standards, the costs of wind, solar and batteries have experienced significant declines over the past decade and these trends are expected to continue in the future. These technologies are also eligible for substantial tax credits under the Inflation Reduction Act (IRA), further improving their economic position. While CCS is a cost-reasonable technology, different modeling platforms may show different levels of adoption, depending on the underlying assumptions around other key factors, such as overall level of demand, cost of competing technologies, and input fuel prices.

In addition to these factors, some models include decision logic that directly impacts the decision to install CCS – one such example is the National Energy Modeling System (NEMS) model which is used by the U.S. Energy Information Administration (EIA) to produce the Annual Energy Outlook (AEO). The capacity planning portion of the Electricity Market Module (EMM) of the NEMS model uses a 30-year planning horizon that is divided into three sub-periods: the current year, the following year, and the remaining 28 years. Capacity decisions, such as retrofits, are made based on technology costs, electricity demand, energy prices, and other factors in the second period but are informed by the third period which represents a net present value (NPV) of the remaining 28 years using expected prices and demands. This representation works well when expectations of the future are similar across future years.

The economics of CCS retrofits are more complex than other capacity planning decisions, and different modeling approaches reflect these economics in different ways. Plants that are eligible for the IRC section 45Q sequestration tax credit receive the subsidy for the first twelve years of operations. Once the credits expire, operating revenues are likely to be negative due to the cost of carbon dioxide (CO_2) capture, transport and storage. Hence the investment would compare favorably to other investments within a twelve- to twenty- year period but would likely be less competitive with other technologies assuming operation over a 28-year period with high utilization throughout both the 12-year tax credit period and the post- tax credit period. Since the NEMS model is currently set up to make investment decisions only on the basis of assuming one mode of operation over the 28-year period, CCS is unlikely to be an economic choice for coal plants under the modeling framework given the cost of competing technologies. However, in models such as IPM where different amortization periods and operating modes can be considered, CCS is more competitive.

The EPA's IPM-based modeling approach thus appropriately reflects the choices and constraints that states, utilities, and grid operators will be making and operating within, respectively. The Agency's reliance on IPM in the context of the Carbon Pollution Standards is both reasonable and consistent with longstanding reliance on this modeling framework to inform long-term planning for the power sector.

3) Evaluation of Energy Ventures Analysis (EVA) Study

Petitioner MSEH states that a low-emitting portfolio lacks attributes necessary to maintain reliability and resource adequacy. This claim is in fact belied by the report released by PJM in

June of 2024 that states that a system that comprises 93 percent carbon-free electricity in PJM by 2035 still maintains reliability.[64] Moreover, according to a recent NREL study, wind, solar and batteries played a vital role in helping meet record 2024 summer peak loads.[65]

The EPA disagrees with Petitioner's claim that the portfolio of resources projected by the EPA's IPM modeling as one potential path to compliance with the Final Rules would interfere with grid reliability. Petitioners cite an EVA study which argues that the level of coal retirement across the PJM footprint projected by the EPA's modeling—a decline of roughly 50 percent of coal capacity between 2023 and 2050 (a 27-year period)—will interfere with PJM's ability to maintain operational reliability. This claim is specious for the reasons discussed below. First, as discussed in section III.A.1.b.i of this document, an operational reliability study based on the EPA's resource adequacy analysis is of questionable utility. Second, the amount of coal retirements that EPA has projected in the PJM footprint is consistent with – and in absolute capacity terms, lower than – the quantity of retirements observed over the last twenty-seven years. Between 1996 and 2003, coal capacity fell from 153 gigawatts (GW) to 73 GW across the PJM states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia) – a decline of approximately 51 percent. Across these same states, coal capacity fell from 138 GW in 2014 to 73 GW in 2023 (a decline of 65 GW over the last ten year period) .[66] The additional 66 GW of coal retirements projected for PJM in the IPM modeling solution supporting the Final Rules between 2023 and 2047 is consistent with this historical rate of retirements. Because IPM's projected level of coal retirements is consistent with what PJM has experienced and adapted to without jeopardizing grid reliability in the past, the EPA does not believe it will necessarily result in risks to reliability moving forward.

Third, EVA's study claims that EPA's projections overestimate additions of new renewable generation capacity, and underestimate future demand growth. However, the growth in renewable resources projected in the EPA's modeling is consistent with the PJM interconnection queue, and is consistent with the recent historical record.[67] While it is true that the baseline EPA modeling does not fully capture the latest PJM demand projections, the EPA performed a high demand growth sensitivity that aligns more closely (the PJM RTO-wide net energy for load growth rate in the higher demand analysis was 1.8 percent over the next ten years, as compared to 2.3 percent under the 2024 PJM load report) with these projections and found resource

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[64] PJM, "Energy Transition in PJM: Flexibility for the Future," June 24, 2024, *https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2024/20240624-energy-transition-in-pjm-flexibility-for-the-future.pdf.*

[65] National Renewable Energy Laboratory, "How the U.S. Power Grid Kept the Lights on in Summer 2024," NREL/TP-6A40-91517, November 2024, *https://www.nrel.gov/docs/fy25osti/91517.pdf.*

[66] EIA, Historical State Data, *https://www.eia.gov/electricity/data/state/.*

[67] For details, see Form EIA 860, September 23, 2024, *https://www.eia.gov/electricity/data/eia860/.*

adequacy was maintained.[68] The EVA study states that the reserve margin contribution of the thermal resources does not align with PJM's findings for Base Residual Auction (BRA) 25/26, announced in March 2024[69] – however, the EPA models summer dependable capacity within IPM, which derates the nameplate capacity and, reduces the need for further derate within the resource adequacy construct. Moreover, the values cited by EVA for EPA's characterization of onshore wind, offshore wind, and energy storage do not take into account the fact that EPA's modeling includes declining reserve margin contributions as a function of penetration – in other words, these values are not static over the forecast period. The EPA thus disagrees with the assertions in the EVA study that its modeling does not consider how various types of resources contribute to grid reliability.

Fourth, the EVA analysis also does not appear to account for imports of capacity into the PJM footprint, nor does it appear to include PJM's interruptible loads, each of which are significant omissions. PJM's ability to import capacity means that, should PJM be short capacity during a particular hour, they can purchase power from neighboring utilities. Moreover, interruptible load refers to customers that opt for lower year-round pricing in return for reducing demand during certain high demand periods, thus lowering peak demand and improving system reliability. Accordingly both of these factors, all else equal, improve resource adequacy and operational reliability attributes, and the EVA modeling does not account for this. Additionally, the EPA's baseline IPM model is populated with a certain level of peak and energy demand, and the model solves for meeting this level of demand.

Fifth, the EVA study assumes the IPM solution is unchanged from the Final Rules scenario but assumes a higher demand and then shows that the reserve margin cannot be met. This is misleading and inappropriate. It ignores the fact that the amount of capacity IPM projected was based on the level of demand that EPA assumed. Had EPA assumed higher demand, IPM's solution would have changed to reflect that higher demand. Moreover, it ignores the fact that the new demand is not caused by EPA rules but by other forces and would exist with or without EPA's rules. Many of the pressures that are leading to the retirement of existing generation (*e.g.*, aging generation and competition from generating resources with lower cost of electricity) would also exist with or without EPA rules. In other words, many of the challenges that the EVA study highlights are not related to the EPA's rules.

Moreover, the EVA analysis was not the only one that sought to use the IPM solution to feed a probabilistic assessment of loss of load – the joint comments submitted by Clean Air Task Force and the Natural Resources Defense Council cited a study that used the outputs of IPM runs to

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[68] Resource Adequacy Analysis: Vehicle Rules, Final 111 EGU Rules, ELG and MATS RTR. Technical Memo for 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 – Final Rule, Document ID No. EPA-HQ-OAR-2023-0072-8915.

[69] PJM, "Effective Load Carrying Capability (ELCC)," *https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability*.

feed a simulation of energy demand in PJM during critical summer and winter periods under weather normal and weather stressed conditions for 2030, 2035, and 2040. In stark contrast to the EVA analysis, this study found that reliability was maintained under all these scenarios by a portfolio that was fully compliant with the EPA rules.[70]

Further, as explained above, the IPM modeling represents only one potential future to demonstrate that there are reasonable approaches to complying with the Final Rules that are both cost effective and consistent with meeting reliability needs. There is also significant new information since the Rules were finalized that suggests that the power sector is on a path to build significantly more zero and low emitting generation than was modeled by EPA. This is documented in both Appendix A: CCS Projects Memorandum and Appendix B: New Electric Generation Memorandum. Examples specifically relevant to PJM include Constellation Energy's recent decision to restart the 835 megawatt (MW) Three Mile Island Unit 1 in Pennsylvania,[71] approval of Competitive Power Venture's 2000 MW combined cycle plant that includes plans for carbon capture and storage in West Virginia and that is projected to begin construction in 2025,[72] and Omnis Energy's continued efforts to convert the Pleasants Coal plant to zero emitting GHG, hydrogen powered facility.[73,74]

2. The EPA's Analysis of Load Growth Was Reasonable, and Petitioner Fails to Satisfy the Standard for Reconsideration on This Point

Petitioner's next claim that recent information on anticipated increases in load growth driven by new electricity demands undermines the EPA's conclusion that the Final Rules will not interfere

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[70] Comment submitted by Clean Air Task Force and Natural Resources Defense Council, December 20, 2023, *ICF, Review of Expected Resource Adequacy in PJM under Stress Conditions during Summer and Winter Peak Periods,* Document ID No. EPA-HQ-OAR-2023-0072-8188.

[71] Reuters, "Three Mile Island nuclear plant gears up for Big Tech reboot," October 22, 2024, *https://www.reuters.com/business/energy/three-mile-island-nuclear-plant-gears-up-big-tech-reboot-2024-10-22/.*

[72] The Parkersburg News and Sentinel, "West Virginia officials approve construction of gas-turbine power plant," *https://www.newsandsentinel.com/news/business/2024/04/west-virginia-officials-approve-construction-of-gas-turbine-power-plant/.*

[73] Fuel Cells Works, "Dr. Saleri to Discuss Omnis Energy Converting Fossil Fuels to Hydrogen and Valuable Graphite - a Project of Firsts," *https://fuelcellsworks.com/2024/09/25/h2/dr-saleri-to-discuss-omnis-energy-converting-fossil-fuels-to-hydrogen-and-valuable-graphite-a-project-of-firsts.*

[74] EVA's critique of the EPA's IPM analysis and its conclusions also ignores the fact that the Final Rules provide significant flexibilities, such as a mechanism to address provision of electricity during grid emergencies and extended compliance timeframes, that states and sources have in complying with the Final Rules. As discussed in the previous section, while the EPA's IPM modeling did not attempt to predict any potential use of these flexibilities, the Agency anticipates states and utilities will avail themselves of these tools when addressing both resource adequacy and reliable operation under those Rules.

with the maintenance of grid reliability. This claim fails on the merits, and Petitioner fails to satisfy either prong of the test for reconsideration under CAA 307(d)(7).

a. Petitioner Had Adequate Notice of EPA's Assumptions Regarding Load Growth and Electricity Demand, and the Final Rule Was a Logical Outgrowth of the Proposal

Under CAA section 307(d)(7), Petitioners seeking reconsideration must demonstrate either that "a person raising an objection can demonstrate … that it was impracticable to raise such objection within such time," or that "the grounds for such objection arose after the period for public comment (but within the time specified for judicial review)." As noted above, the EPA provided a resource adequacy analysis with its Proposed Rules that was available for public comment,[75] in addition to requesting comment specifically on reliability-related considerations in its Supplemental Proposal.[76] Assessing potential impacts on future resource adequacy and reliability requires making assumptions about electricity demand in the future. Thus, the EPA's assumptions about load growth in the baseline and policy scenarios it analyzed were a critical component of the resource adequacy analyses which were subject to public comment. Furthermore, the EPA received and responded to comments stating that the Proposed Rules would increase threats to reliability given increasing load growth spurred by electrification and data centers, at a time when many fossil assets are already slated for retirement.

Petitioner MSEH provided information in its petition regarding PJM's most recent load forecast update, released on January 2024, as well as a new study on projected increases in electricity demand in PJM from May 2024. Both of these resources became available after the public comment periods for the Proposed Rules and the Supplemental Proposal closed, but within the time specified for judicial review. However, while the information MSEH cites is more recent, it does not raise any objections to the Rules that the EPA had not already received and addressed as part of the rulemaking. Therefore, Petitioner MSEH's objection fails the first prong for reconsideration under CAA section 307(d)(7)(B) because MSEH had adequate notice of and opportunity to comment on the EPA's assumptions about load growth and electricity demand for purposes of its resource adequacy analysis as part of the rulemaking process.

b. Petitioner's Claims Regarding Load Growth are Not of Central Relevance to the Outcome of the Rule

Second, Petitioner's claim fails the central relevance prong because it has failed to show that the EPA would have reached a different outcome had the load growth information that it identifies in its petition been before the EPA during the rulemaking proposal. While the EPA acknowledges

[75] Resource Adequacy Analysis Technical Support Document for 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 – Proposal ("Resource Adequacy TSD – Proposal"), Document ID No. EPA-HQ-OAR-2023-0072-0034.
[76] 88 FR 80684.

that recent information on load growth indicates a trend of increasing demand, the information provided does not disturb its conclusion that the Final Rules will not interfere with grid reliability notwithstanding anticipated load growth and increased energy demand.

As noted above, the EPA received comments regarding reliability concerns related to load growth. The EPA responded with information about the many ways in which the Final Rules were adjusted to provide more flexibility for states, utilities, and grid operators to make decisions about what resources will be available and when, including through changes to the structure of the Rules' subcategories; an explicit provision for addressing reliability using the framework for states to consider existing sources' remaining useful lives and other factors; the inclusion of reliability- related mechanisms; updated resource adequacy modeling, including the high demand load sensitivity run; and an explanation of that there are the many traditional processes already in place lead by grid operators to plan for load growth. In fact, many states are actively planning to maintain reliability during forecasted load increases in the same timeframe as assets within their footprint transition to newer, cleaner technologies.[77]

The assertion that load growth and carbon pollution abatement are mutually exclusive is a false paradigm. While the precise amount of projected load growth that will actually materialize cannot yet be known, it is the case that utilities have historically underestimated the amount of clean energy that is ultimately deployed to meet growing demand.[78] Moreover, the Department of Energy has characterized load growth as, "an opportunity to accelerate the build out of clean energy solutions," and has awarded multiple funding opportunities to help leverage clean electricity deployment to support data center related demand growth and grid reliability.[79]

In conducting the modeling for this rulemaking, the EPA adopted the latest available information at the time of the analysis. Data on electricity demand were taken from the AEO 2023 projections, and updated to account for the additional anticipated demand due to the EPA's vehicle rules, while data on power sector fleet composition (*i.e.*, existing units, planned/committed units and retirements) were taken from EIA 860 data and market research at the time of the analysis.[80] This resulted in EPA's baseline scenario featuring modeled electricity sales that were roughly 6 percent and 8 percent higher than AEO 2023 projections in 2035 and 2040, respectively.

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[77] See, *e.g.*, Transcript of Harvard Law School Environmental & Energy Law Program Webinar: "State Perspectives on Power Sector Changes," April 10, 2024, Docket ID No. EPA-HQ-OAR-2023-0072-8940.
[78] See Rocky Mountain Institute, "Reality Check: Electricity Load Growth Does Not Have to Undermine Climate Goals," September 16, 2024, *https://rmi.org/reality-check-electricity-load-growth-does-not-have-to-undermine-climate-goals/*.
[79] U.S. Department of Energy, "Clean Energy Resources to Meet Data Center Electricity Demand," August 12, 2024. *https://www.energy.gov/policy/articles/clean-energy-resources-meet-data-center-electricity-demand*.
[80] U.S. EPA, RIA Section 3 – Compliance Costs Emissions and Energy Impacts Final - NEEDS for 2023 Reference Case, Document ID No. EPA-HQ-OAR-2023-0072-8396.

The EPA was aware of increasing demand forecasts which were discussed during the extensive stakeholder outreach to independent system operators (ISOs), regional transmission organizations (RTOs), utilities and balancing authorities – though the full extent of data center-related load had not yet crystalized at that time. Because projections of load growth based on data-center demand were, at the time of the rulemaking, relatively nascent, the EPA did not incorporate them into its modeling for the Final Rules. However, in recognition of the overarching load growth concerns raised during stakeholder outreach, the EPA developed an additional high demand sensitivity run in which, by 2040, annual electricity demand was about 11 percent higher and peak demand is 6 percent higher than under the baseline.[81] This scenario resulted in modeled electricity sales that were roughly 11 percent and 16 percent higher than AEO 2023 projections in 2035 and 2040, respectively.[82] The EPA also analyzed a scenario that included all of the Agency's power sector-related rules. Both modeling cases demonstrated that an adequate portfolio of resources would be available to the grid with sufficient reliability attributes under the EPA's rulemaking.[83]

Under the EPA's baseline scenario, load growth in PJM was projected to be 1.29 percent annually, on average, over 2024-2035. In the scenario that included all of the EPA's power sector rules, PJM load growth was projected to be 1.75 percent annually over 2024-2045. PJM's January 2023 load report predicted a growth rate of 1.4 percent annually, on average for the next ten years,[84] with the figure from PJM's January 2024 report rising to 2.3 percent.[85] At least a portion of this projected increase is attributed to growth in data center load.[86] However, as described above, not all of this projected increase in electric demand is anticipated to materialize, due to both the historical tendency to overestimate demand generally, and the specific uncertainty in where data centers will be sited that has led, in some cases, to double counting of anticipated demand in multiple regions.

Moreover, emerging electricity demand due to data center growth has been coupled with supply side developments that are likely to moderate the impacts of such growth on the grid. Many data centers in the planning and development stages are accompanied by requests to power this

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[81] U.S. EPA, "Technical Memo - IPM Sensitivity Runs," April 2024, Docket ID No. EPA-HQ-OAR-2023-0072-8917.
[82] *Id.*
[83] Resource Adequacy Analysis: Vehicle Rules, Final 111 EGU Rules, ELG and MATS RTR. Technical Memo for 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 – Final Rule. Document ID No. EPA-HQ-OAR-2023-0072-8915.
[84] PJM Load Forecast Report, January 2023 at 2, *https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2023-load-report.pdf*.
[85] PJM Load Forecast Report, January 2024 at 2, *https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2024-load-report.pdf*.
[86] See *id*. at 1-2.

incremental load with zero or low carbon electricity.[87] This is evidenced by the significant premiums on power purchase agreements signed by these loads to ensure that they are able to secure necessary low emitting resources, and is directly linked to a number of proposed nuclear restarts. These include the planned restart of the Palisades nuclear plant, as well as Three Mile Island.[88] A number of small modular nuclear reactors have been announced as well, in addition to technologies such as advanced geothermal, which are also not reflected in the modeling, and which would, all else equal, likely partially offset this new load.[89] In addition to nuclear energy, data centers are also turning to new sources of geothermal energy for their primary power and cooling needs.[90] The anticipated addition of zero or low-carbon capacity to serve increasing data center demand belies assertions that this projected increase necessarily undermines the EPA's analysis and conclusions that the Final Rules will not interfere with the maintenance of resources adequacy or reliability. These new zero and low GHG projects are further detailed in Appendices A and B of this document.

Further, Petitioner's assertion that only firm dispatchable assets, such as their gas-fired combined cycle unit, can stabilize the grid in light of load growth challenges, is false. First, as discussed in section III.B of this document below, the EPA disagrees with the implication that such units are not able to achieve the standards in the Final Rules and will thus be unavailable to serve demand in the future. In fact, new gas assets with CCS are well positioned to help mitigate new load: multiple companies are offering NGCC with CCS to support data center load growth.[91] Second,

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[87] S&P Global, "Datacenters companies continue renewable buying spree, surpassing 40 GW in the US," March 28, 2023, *https://www.spglobal.com/market-intelligence/en/news-insights/research/datacenter-companies-continue-renewable-buying-spree-surpassing-40-gw-in-us, https://www.spglobal.com/content/dam/spglobal/ci/en/images/platts/latest-news/121624-infographic-global-data-centers-clean-energy-sourcing.png;* S&P Global, "Data centers' growing power appetite set to transform clean energy procurement," December 16, 2024, *https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/121624-infographic-data-centers-clean-energy-demand-sourcing*.

[88] See Nuclear Regulatory Commission, "NRC Preparing to Oversee First of a Kind Effort to Restart a Shuttered Plant," 2023; "Palisades on schedule for repowering, NRC considers restart regulations," *https://www.nrc.gov/info-finder/reactors/pali.html;* World Nuclear News, September 19, 2024, "Three Mile Island nuclear plant gears up for Big Tech reboot," Reuters, October 22, 2024, *https://www.reuters.com/business/energy/three-mile-island-nuclear-plant-gears-up-big-tech-reboot-2024-10-22/*.

[89] Utility Dive, "Meta seeks up to 4 GW of new nuclear power to help meet AI, sustainability objectives," December 4, 2024, *https://www.utilitydive.com/news/meta-seeks-up-to-4-gw-of-new-nuclear-power-to-help-meet-ai-sustainability/734599/*.

[90] Data Center Dynamics, "Meta signs geothermal energy deal to power data centers in US," August 27, 2024, *https://www.datacenterdynamics.com/en/news/meta-signed-geothermal-energy-deal-to-power-data-centers-in-us/.*

[91] Power Magazine, "ExxonMobil Planning Large Gas-Fired Plant to Serve Data Centers," December 11, 2024, *https://www.powermag.com/exxonmobil-planning-large-gas-fired-plant-to-serve-data-centers/*; Power Magazine, "NET Power and CRC Team to Deploy 1 GW of Carbon-

the pace of development of zero- or low-carbon emitting generation, as well as energy storage, is such that the EPA's projections of future resources are most likely conservative and underrepresent the actual amount of generation that will be available to meet future electricity demand. That is, although some projections of electricity demand are higher than what the EPA modeled in its IPM scenarios, recent information has shown that new zero- and low-carbon capacity is also increasing faster than anticipated. This provides further support for the EPA's conclusion that implementation of the Final Rules will not interfere with reliability notwithstanding the anticipated load growth.

For example, while IPM projects an annual average increase in utility-scale solar of 17.75 GW per year, the EIA reported that the U.S. is on track to install nearly 37 GW of utility-scale solar in 2024.[92] Similarly, IPM projects growth in short-term energy storage from 15 GW in 2023 to 113 GW in 2035 (average annual increase of slightly less than 8.2 GW per year), and growth in long-term energy storage from 9 GW in 2023 to 12 GW in 2035 (an increase of about 1 GW per year, on average). However, for 2024 EIA projected that 15 GW of energy storage would be built[93]; there are also multiple long-term energy storage projections under development in the United States. For more information, see Appendix B: New Electric Generation Memorandum.

Moreover, as multiple studies have shown, a portfolio approach to developing capacity that includes invertor-based resources, including solar, wind, and energy storage, can also collectively provide essential reliability attributes and respond to rapid changes to generation and transmission availability.[94] In fact, according to a recent study by NREL, "dozens of studies have been conducted to evaluate questions associated with maintaining reliability in power systems with an increased deployment of variable renewable energy (wind and solar). These studies have identified approaches to cost-effectively address the variability and uncertainty of solar and wind resources. Many of these approaches have been implemented, enabling a growing contribution of variable renewable energy resources in today's grid."[95] A separate NREL publication underscores that point, explaining that "several regions in the country (and many around the world) have achieved very high contributions from renewable energy over shorter timescales. This has demonstrated the ability to maintain operational reliability with new approaches and

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Free Gas Power Plants in California," December 11, 2024, *https://www.powermag.com/net-power-and-crc-team-to-deploy-1-gw-of-carbon-free-gas-power-plants-in-california/*.

[92] U.S. Energy Information Administration, "Solar and Battery Storage to Make Up 84% of New U.S. Electric-Generating Capacity in 2024," February 15, 2024, *https://www.eia.gov/todayinenergy/detail.php?id=61424*.

[93] U.S. Energy Information Administration, "U.S. Battery Storage Capacity Expected to Nearly Double in 2024," January 9, 2024, *https://www.eia.gov/todayinenergy/detail.php?id=61202*.

[94] National Renewable Energy Laboratory, "Operational Reliability," *https://www.nrel.gov/research/operational-reliability.html*.

[95] National Renewable Energy Laboratory, "Maintaining Grid Reliability – Lessons from Renewable Integration Studies," NREL/TP-5C00-89166, April 2024, *https://www.nrel.gov/docs/fy24osti/89166.pdf*.

practices."[96] Thus, grids with or without firm dispatchable assets such as base load NGCC are capable of maintaining both resource adequacy and operational reliability. Further, because the grid is already changing rapidly, independent of the Carbon Pollution Standards (with new generation resources coming on-line, demand growing, new transmission projects being developed, opportunities for advanced technologies to upgrade existing transmission etc.), grid operators, state and federal regulators, and utilities must address many of the concerns raised by petitioners even if the Final Rules were not in place.

2. The EPA's Decision to Deny the Petition for Rulemaking on the Grounds Outlined Above is Reasonable under the APA

In regards to Petitioner MSEH's petition for rulemaking under APA section 553(e), notwithstanding Petitioners' arguments regarding reliability, Petitioner has identified no compelling reason for the EPA to reopen or revise these Final Rules. Thus, for the same reasons outlined above, the EPA's decision to deny Petitioner MSEH's petition for rulemaking under section 553(e) is reasonable and entitled to deference.

B. New Natural Gas Combined-Cycle Turbines – Carbon Capture and Storage and Financing Assertions

Petitioner MSEH stated that reconsideration is warranted because the Final Rules apply to more new base load combustion turbines and include a shorter compliance deadline than proposed, and that these changes will make financing of new energy projects impossible.[97] However, Petitioner fails to satisfy either prong of the test for reconsideration under CAA 307(d)(7) on this issue.

1. Petitioner Had Adequate Notice of the Final Rules Applicability and Timelines, and the Final Rules were a Logical Outgrowth of Proposal on this Point

First, contrary to Petitioners' assertions, the Final Rules' applicability and timelines were a clear logical outgrowth of the Proposed Rules. While the EPA proposed to define a 50 percent capacity factor as the threshold between baseload and intermediate turbines, the EPA explicitly solicited comment on reducing that threshold, stating, "EPA is soliciting comment on whether the intermediate/base load electric sales threshold should be reduced further. The EPA is considering a range that would lower the base load electric sales threshold for simple cycle combustion turbines to between 29 to 35 percent (depending on the design efficiency) and to between 40 to 49 percent for combined cycle combustion turbines (depending on the design efficiency)."[98] MSEH did not raise this issue of capacity factor threshold in its comments on the Proposed Rules, but other commenters did comment on this issue, and the EPA summarized and

[96] National Renewable Energy Laboratory, "Explained: Fundamentals of Power Grid Reliability and Clean Electricity," NREL/FS-6A40-85880, January 2024, *https://www.nrel.gov/docs/fy24osti/85880.pdf*.
[97] Mountain State Energy Holdings, LLC's Petition for Rulemaking and Reconsideration, July 30, 2024. Available in Docket ID No. EPA-HQ-OAR-2023-0072.
[98] 88 FR 33319.

responded to those comments in section VIII.E.2.b.ii of the preamble to the Final Rules.[99] Thus, parties had ample notice of, and an opportunity to comment on, the EPA's consideration of a lower threshold for defining base load turbines.

Further, while the EPA proposed the second component of BSER for new base load turbines to apply beginning in 2035, the EPA also explicitly solicited comment on this issue, stating, "EPA also recognizes that commenters may have more information about implementing CCS on a broader scale that would help to assess whether 2030 or 2035 (or somewhere in between) would be an appropriate start date for phase 2 of the standards of performance that are based, in part, on the use of CCS. For this reason, the EPA solicits comment on whether the compliance date for phase 2 of the standards of performance should begin earlier than 2035, including as early as 2030."[100] MSEH commented on the compliance deadline for CCS, stating that "there is absolutely no way the required … CCUS [carbon capture, utilization, and sequestration/storage] infrastructure can be engineered, permitted, financed, build, and reach commercial operation in the timeframe (2030) [sic] required under this Proposed Rule. Most major initiatives to this point have identified 2050 and beyond as a potential milestone for efforts of this grand scale and cost."[101] Other commenters commented on this issue as well, and the EPA summarized and responded to all comments on this issue in section VIII.F.4.c.iv(I) of the Final Rules[102] and Response to Comments Document, chapter 4: Carbon Capture, Transportation, and Sequestration/Storage.[103] Therefore, MSEH is incorrect that the EPA "did not propose, request comment on, or even hint at a shorter compliance deadline."[104]

Thus, the EPA's threshold and compliance date for new base load combustion turbines in the Final Rules were logical outgrowths of its Proposed Rules. See, *e.g.*, *United States Telecom Ass'n v. FCC*, 825 F.3d 674, 700 (D.C. Cir. 2016) (a final rule is a logical outgrowth of the proposal when the Agency has "expressly ask[ed] for comments on a particular issue or otherwise ma[de] clear that the agency [was] contemplating a particular change"); *Fertilizer Inst. v. EPA*, 935 F.2d 1303, 1311 (D.C. Cir. 1991) (quoting *BASF Wyandotte Corp. v. Costle*, 598 F.2d 637, 644-45 (1st Cir. 1979) (consideration is whether a new round of notice and comment would provide parties with "their first occasion to offer new and different criticisms which the agency might find convincing"). Because it was not impracticable for MSEH to have raised the base load threshold or compliance date during the rulemaking, the EPA denies the petition for reconsideration on this point.

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[99] 89 FR 39910.
[100] 88 FR 33304.
[101] Comment submitted by Mountain State Energy Holdings, LLC. August 8, 2023. See Document ID No. EPA-HQ-OAR-2023-0072-0829.
[102] 89 FR 39938-39.
[103] U.S. EPA, Response to Comments Document, April 2024, Document ID No. EPA-HQ-OAR-2023-0072-8914.
[104] Mountain State Energy Holdings, LLC's Petition for Rulemaking and Reconsideration at 13, July 30, 2024. Available in Docket ID No. EPA-HQ-OAR-2023-0072.

2. Petitioner's Claims Regarding Project Financing are Not of Central Relevance to the Outcome of the Final Rules

Second, Petitioner's claim regarding project financing fails the central relevance prong because Petitioner has failed to show that the EPA would have reached a different outcome had the financing information that it identifies in its petition been before the EPA during the rulemaking Proposal.

MSEH claims in its petition that "[f]inanciers refuse to take the risk that EPA's mandates in the Final Carbon Rule are technically and economically feasible within the time limits specified within the Rule. As a merchant plant, costs of the project cannot be passed on to ratepayers, so the viability of the project lies in the hands of financiers and their assessment of the Final Rule's feasibility."[105] MSEH claims that its subsidiary, Mountain State Clean Energy, LLC (MSCE), is unable to obtain financing for a planned combined cycle gas turbine unit because the CCS-based requirements in the Carbon Pollution Standards rule are, according to MSEH, infeasible.

First and foremost, the EPA has already conclusively addressed the feasibility of the standards in the record supporting the Final Rules. The EPA determined that these standards of performance, which were crafted with sufficient lead time for planning and implementation of the CCS-based controls, are achievable within the compliance timeframe.[106] The MSCE asset is in West Virginia, which participates in a deregulated wholesale market, PJM. In essence, the Petitioner asserts that the EPA's Rules are inhibiting the MSCE plant's ability to secure financing based, allegedly, on financier's assessment that the CCS-based standards for new NGCC units in the EPA's Final Rules are not feasible, contrary to the EPA's record-based determination. Moreover, Petitioner fails to supply evidence to support its claim that financing cannot be found for new gas assets or to provide a rational link to the EPA's Rules as the cause of any eroding investor interest in its asset. Because MSEH has not supported this central premise of its petition, the EPA finds that MSEH's arguments regarding the financial viability of its new asset and the Final Rules' purported impact on that viability are not centrally relevant.

Second, the sustained pace of development of new natural gas-fired power plants in diverse regions of the country contradicts MSEH's unsupported assertions that the Final Rules are preventing the company from securing financing. Financiers assess the ability of a prospective asset to recover costs and generate a return on investment (ROI) by estimating projected revenue and earnings before interest, taxes, depreciation, and amortization (EBITDA). Financiers also assess other risk factors, like market structures and trends, interconnection wait times, and environmental compliance requirements, as well as relevant emerging policy trends at the local, state, RTOs, and national level that may create a tailwind or headwind to projected returns from a target asset. In recent years, developers of natural gas-fired generation have faced some

[105] Mountain State Energy Holdings, LLC's Petition for Rulemaking and Reconsideration at 2, July 30, 2024. Available in Docket ID No. EPA-HQ-OAR-2023-0072.
[106] See section VIII.F.4.c.iv(I) of the preamble to the Final Rules (89 FR 39938-39) for base load natural gas-fired combustion turbines and section VII.C.1.a.i(E) of the preamble to the Final Rules (89 FR 39874-75) for long-term coal-fired steam generating units.

headwinds, as noted below, including volatile energy prices due to the Covid-19 pandemic and recovery and the Ukraine war, supply chain issues and associated cost increases, and delays in connecting new sources to the grid.[107]

Even so, power sector trends and available market data demonstrate that the pipeline for new natural gas-fired power plants in the U.S. is robust. Bloomberg reports new natural gas plants are being planned "at the fastest pace in years" and that in the first half of 2024, "companies have announced plans to build more new gas power capacity across the U.S. than they did in all of 2020" and more are expected in the latter half of the year.[108] Petitioner asserted that the EPA's Final Rules are impinging on MSEH's ability to secure financing for a fully permitted new 1,100 MW combined cycle gas turbine with hydrogen co-firing capabilities. But these unsupported assertions fly in the face of the ongoing, robust development of natural gas-fired generation, a development could not be occurring absent the ability to secure financing. Indeed, according to S&P Global, there are at least 133 new natural gas-fired power plants planning to connect to the grid that are either announced, in development or under construction.[109] This analysis does not break down which of the projects are fully financed but given that some are in advanced planning and others under construction, it is a strong indicator that financing for this asset class is, contrary to the Petitioner's assertions, abundantly available. Bloomberg's estimates are even

[107] Concern over extreme weather fueled by climate change could also be a headwind. The National Oceanic and Atmospheric Administration declared 2023 the hottest year on record dating back to 1850, National Oceanic and Atmospheric Administration, National Centers for Environmental Information. "Assessing the Global Climate in 2023". January 12, 2024. *https://www.ncei.noaa.gov/news/global-climate-202312*; and cost of extreme weather-related events in 2023 was estimated at $93 billion. National Oceanic and Atmospheric Administration, National Centers for Environmental Information. "2023: A historic year of U.S. billion-dollar weather and climate disasters." January 8, 2024. *https://www.climate.gov/news-features/blogs/beyond-data/2023-historic-year-us-billion-dollar-weather-and-climate-disasters*. Many states, including some within the PJM footprint, have stringent policies to reduce the amount of fossil-fired electricity generated, including putting a price on each ton of emissions from fossil EGUs. Regional Greenhouse Gas Initiative, Inc. "CO_2 Allowances Sold for $25.75 in 65th RGGI Auction". September 6, 2024. *https://www.rggi.org/sites/default/files/Uploads/Auction-Materials/65/PR090624_Auction65.pdf*.

[108] Bloomberg, "US Natural Gas Power Plants Just Keep Coming to Meet AI, EV Electricity Demand," September 16, 2024, *https://www.bloomberg.com/news/articles/2024-09-16/us-natural-gas-power-plants-just-keep-coming-to-meet-ai-ev-electricity-demand*.

[109] S&P Global, "US has 133 new gas-fired plants in the works, putting climate goals at risk," | May 15, 2024, *https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/us-has-133-new-gas-fired-plants-in-the-works-putting-climate-goals-at-risk-81469493.*

higher than S&P's: they reported more than 200 gas assets in development totaling over 85 GW of capacity.[110]

New natural gas assets are coming online in both restructured, wholesale markets organized by RTOs and ISOs, like the Petitioner's asset, and in vertically integrated states, according to the S&P Global report.[111] Financing is more straightforward in vertically integrated states where utilities develop integrated resource plans that are approved by state regulators for rate recovery from rate payers. Regardless, data from S&P Global suggest there is ample financing for natural gas plants in vertically integrated states as well as those located in wholesale markets. According to their analysis, about 18 GW of new gas capacity is planned in vertically regulated states.[112] Yet over twice as much gas capacity is projected across wholesale markets: nearly 16 GW is planned in Electric Reliability Council of Texas (ERCOT) alone, nearly 12 GW is planned in Midwest Independent System Operator (MISO), and over 10 GW is planned in PJM, the very market where Petitioner claims financing cannot be secured for new gas assets. Conditions for financing depend on multiple factors, including favorable and stable market rules; visible, functional, and expedient interconnection queue wait times; and of course, projected revenues from key market products. The EPA's Rules are national, applying to all continental states equally and many RTOs are clearly able to attract financing for new natural gas assets.

Moreover, recent developments in PJM contradict MSEH's claims that the Final Rules are causing difficulties obtaining financing. A similar combined-cycle power plant, Shay Energy Center, with GE HA.02 turbines and a carbon capture system, currently under development by another independent power producer in West Virginia, Competitive Power Ventures (CPV), has secured initial financing, with CPV's estimated closure and financing completion predicted by the second quarter of 2026, according to a West Virginia Public Service Commission Order.[113] In addition, the PJM Interconnection encompasses multiple markets including energy, capacity, and ancillary services like voltage support and frequency regulation and these markets could be revenue sources for MSEH's combined cycle turbine that could support financing. This would be true if MSEH chose to operate the turbine at a capacity factor of 40 percent or lower and did not

[110] Bloomberg, "US Natural Gas Power Plants Just Keep Coming to Meet AI, EV Electricity Demand," September 16, 2024, *https://www.bloomberg.com/news/articles/2024-09-16/us-natural-gas-power-plants-just-keep-coming-to-meet-ai-ev-electricity-demand*.
[111] S&P Global, "US has 133 new gas-fired plants in the works, putting climate goals at risk," | May 15, 2024, *https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/us-has-133-new-gas-fired-plants-in-the-works-putting-climate-goals-at-risk-81469493.*
[112] *Id.*
[113] Public Service Commission of West Virginia, Case No. 23-0910_E-CS-CN. CPV Shay, LLC, Application of CPV Shay, LLC for Siting Certificate, Certificate of Public Convenience and Necessity, and Related Waivers and Approvals for a Wholesale Electric Generating Facility and a High-Voltage Electric Transmission Line in Doddridge County, West Virginia. Commission Order, *https://www.psc.state.wv.us/scripts/orders/ViewDocument.cfm?CaseActivityID=621601&Source=Docket.*

install CCS. Petitioner claims that its combined cycle turbine is "the most efficient unit of its kind in the nation"[114] -- as a result, it could expect to compete well and be preferentially dispatched in PJM's energy market. Moreover, PJM's capacity prices have recently been increasing, which led Calpine, the largest natural gas fleet owner and operator in the country, to announce in August 2024 that it was "accelerating its PJM electricity generation development program following market signals indicating higher demand for reliable power."[115,116] In addition, MSEH's asset would have load-following capabilities and could also compete for voltage support and frequency regulation products to help balance the grid as more intermittent resources enter PJM. In fact, many analysts believe that prices for ancillary products that help balance renewables are likely to increase with increasing renewable penetration.[117] By the same token, if MSEH chose to operate the turbine at a capacity factor above 40 percent and installed CCS, the CCS tax credit would offset the CCS operating costs for the period when the tax credit is available,[118] so that with CCS, the asset could also expect to be preferentially dispatched and compete well in the various PJM markets noted above.

In addition to CPV's Shay Energy Center, noted above, 13 NGCC projects with CCS, including both new and existing EGUs, are under development in the U.S.[119] In addition to Shay Energy, six of the other 13 NGCC projects with CCS under development in the U.S. are new units, including an additional project in Texas being developed by CPV[120] and two projects being developed by Net Power (one in Texas and one in a currently undisclosed state in the MISO region).[121] Other new projects include a Tri-state power project[122] and a project being developed by Exxon.[123] In addition, as recently as December 2024, California Resources Corporation, and

[114] Mountain State Energy Holdings, LLC's Petition for Rulemaking and Reconsideration at 1. July 30, 2024. Available in Docket ID No. EPA-HQ-OAR-2023-0072.
[115] Calpine, "Calpine Accelerates PJM Development Program," August 22, 2024, *https://www.calpine.com/calpine-accelerates-pjm-development-program/*.
[116] S&P Global, "Calpine signals plans to ramp up generation development in PJM," August 26, 2024, *https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/calpine-signals-plans-to-ramp-up-generation-development-in-pjm-83064266.*
[117] Brattle, "Briefing Summary: Bulk System Reliability for Tomorrow's Grid," February 20, 2024, *https://www.brattle.com/wp-content/uploads/2024/01/Briefing-Summary-Bulk-System-Reliability-for-Tomorrows-Grid.pdf*.
[118] *See* TSD, Greenhouse Gas Mitigation Measures – Carbon Capture and Storage for Combustion Turbines for the Final Rules at 11 (Figure 7) (The overall increase in the incremental generating costs from CCS (*i.e.*, increase in variable operating costs, fuel costs, and TS&M of the captured CO_2) for new combustion turbines are \$11.3 - \$13.0/MWh; value of the IRC §45Q tax credit is \$12.2 - \$12.6/MWh). Document ID No. EPA-HQ-OAR-2023-0072-9099.
[119] Appendix A at A-1.
[120] *Id.* at A-7 (CPV Basin Ranch, Texas).
[121] *Id.* at A-7-A-8 (Net Power – Project Permian, Net Power MISO Project).
[122] *Id.* at A-9(Tri-state Generation).
[123] *See* TSD, "Greenhouse Gas Mitigation Measures – Carbon Capture and Storage for Combustion Turbines" for Final Rules at 32. Document ID No. EPA-HQ-OAR-2023-0072-9099. *See also* Appendix A at A-8.

its carbon management business, Carbon TerraVault, announced the signing of an MOU with Net Power to develop up to 1 GW of power capacity in California from NGCC plants that will capture "substantially all" of their carbon emissions.[124] Furthermore, there are 7 projects to retrofit existing NGCC units with CCS in the U.S.[125] There are also additional projects being developed internationally.[126] And numerous vendors are supplying CCS systems that are designed for at least 90 percent capture, and in many cases for 95 percent or higher capture.[127] Additional information on projects under development and vendors supplying CCS systems can be found in Appendix A: CCS Projects Memorandum.

The transport and sequestration infrastructure necessary to support these new projects with CCS are also developing apace. While the EPA's costing analysis in the Final Rules took the conservative assumption that each EGU would develop its own pipeline and sequestration facility, in many states, companies are developing sequestration hubs that can support multiple projects. The EPA is aware of at least 10 states where sequestration hubs are under development or operating, including Alabama, California, Louisiana, Michigan, New Mexico, North Dakota, Ohio, Pennsylvania, Texas and West Virginia. There are also some states that already have existing CCS pipeline networks. These are primarily delivering naturally occurring CO_2 to enhanced oil recovery (EOR) sites, but there are opportunities to repurpose them to move captured CO_2 to Class VI storage sites. These states include Colorado, Kansas, Mississippi, New Mexico, Oklahoma, Texas and Wyoming. A multi-state pipeline is in development in Iowa, Minnesota, Nebraska, North Dakota and South Dakota. This pipeline is being developed to support multiple industry sources and a Class VI UIC sequestration site in North Dakota. Additional information on these projects can be found in Appendix A: CCS Projects Memorandum. In addition, EPA's Class VI UIC program is actively processing primacy applications.[128] States seeking to administer their own Class VI UIC programs are in various phases of the primacy application process, and three states (Louisiana, North Dakota, and Wyoming) have already obtained primacy over their Class VI programs.[129]

In addition, MSEH stated that its long-term plan for the NGCC unit under development by MSCE is to fire it on 100 percent hydrogen. It appears that this long-term plan is independent of EPA's Final Rules and rather due to market drivers favoring lower GHG technologies. If the

[124] Net Power, "Carbon TerraVault and Net Power Sign MOU to Develop Low Carbon, Reliable Power Solutions in California," *https://netpower.com/press-releases/carbon-terravault-and-net-power-sign-mou-to-develop-low-carbon-reliable-power-solutions-in-california/*. See also Sonal Patel, "NET Power and CRC Team to Deploy 1 GW of Carbon-Free Gas Power Plants in California", *Power* (December 11, 2024). *https://www.powermag.com/net-power-and-crc-team-to-deploy-1-gw-of-carbon-free-gas-power-plants-in-california/*. Appendix A at A-8.
[125] *See* TSD, "Greenhouse Gas Mitigation Measures – Carbon Capture and Storage for Combustion Turbines" for Final Rules at 32-39. Document ID No. EPA-HQ-OAR-2023-0072-9099; *see also* Appendix A at A-3-A-7.
[126] *See* Appendix A at A-9.
[127] *Id.* at A-11-A-15.
[128] *See* Appendix A: CCS Projects Memorandum, section III: CO_2 Sequestration and CCS Hubs.
[129] *See id.*

plant were to fire greater than 95 percent hydrogen, it would be able to comply with the emissions standards for new NGCC units in the Final Rules, without having to install CCS. MSEH provided very little information in its petition about how it intends to convert the plant to hydrogen; as a result, the EPA is unable to consider the timing or specific aspects of that approach. In general, however, the EPA believes there are viable paths to converting a turbine to combust 100 percent hydrogen. The EPA's understanding of potential approaches that could be taken to combust hydrogen at this plant are also laid out in Appendix A: CCS Projects Memorandum.

Petitioner supplied no evidence that its inability to finance the MCSE turbine is due to the Final Rules. If financing for this project is indeed proving difficult, this may be the result of other factors. Investors consider many factors. For example, a study from Columbia University points to PJM's interconnection process, which has led to delays in connecting new sources to the grid, as a financing impediment identified by market participants.[130] Other observers have raised concerns over PJM's capacity auction schedule.[131] In fact, in a separate filing to the West Virginia Public Service Commission, Petitioner argued that a number of other factors had contributed to delay of the project, stating:

> Since the Commission's issuance of the Order in April 2020, Petitioners [MSEH] and other energy developers have faced weak capacity prices and volatile energy prices as the Covid-19 pandemic, the ensuing economic recovery, and the Ukraine war have combined to bring instability and uncertainty to large energy infrastructure investments. Equipment procurement and supply chain issues have significantly increased lead times, and cost increases arising during this period persist today.[132]

Petitioner added, "[i]n addition, uncertainties surrounding pending environmental regulations for gas-fired generation have complicated efforts to finance the construction of those units."[133] Importantly, in noting that "uncertainties … have complicated efforts," Petitioner did not represent that CCS requirements make it impossible to finance the units. In fact, Petitioner added, "[s]pecifically, the MSCE combined cycle project, as a fully developed project with State siting authority and a finalized interconnection agreement with PJM, presents an attractive

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[130] Center on Global Energy Policy at Columbia University SIPA, "Outlook for Pending Generation in the PJM Interconnection Queue," May 2024, *https://www.energypolicy.columbia.edu/publications/outlook-for-pending-generation-in-the-pjm-interconnection-queue/*.

[131] Natural Resources Defense Council, "PJM's Capacity Auction: The Real Story," August 22, 2024, *https://www.nrdc.org/bio/claire-lang-ree/pjms-capacity-auction-real-story*.

[132] Mountain State Clean Energy, LLC and Mountain State Renewables, LLC, "Joint Petition to Reopen and for Relief under Condition 10," Public Service Commission of West Virginia, page 2, par. 3 (October 9, 2024), *http://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=630406*.

[133] *Id.*

opportunity when compared with similar projects under development in the PJM region that can expect a significantly delayed interconnection process."[134]

Petitioner argued the dearth of investor interest in its MSCE turbine is exacerbated by the difficulty of competing with existing gas assets for which emissions constraints were not finalized in the Final Rules. This argument is not persuasive. If Petitioner elects to install CCS on the turbine by 2032, in accordance with the Final NSPS, the unit should in fact be quite competitive with existing generation for the period before 2032 because, as noted above, the unit is likely to be one of the most efficient units in PJM.[135] And for the period from 2032-2044, when the unit would be using CCS and would be eligible to receive the IRC §45Q tax credit, the unit would also likely be quite competitive with existing units without CCS because, again as noted above, the amount of the tax credit would offset the operating costs.

3. The EPA's Decision to Deny the Petition for Rulemaking on the Grounds Outlined Above is Reasonable under the APA

In regards to Petitioner MSEH's petition for rulemaking under APA section 553(e), notwithstanding Petitioner's arguments regarding financing of new gas projects, Petitioner has identified no compelling reason for the EPA to reopen or revise these Final Rules. Thus, for the same reasons outlined above, the EPA's decision to deny Petitioner MSEH's petition for rulemaking under section 553(e) is reasonable and entitled to deference.

C. Backstop Rate

Petitioner EEI requested that the EPA rescind the requirement of an enforceable backstop emission rate in conjunction with mass-based compliance flexibilities and argued that the EPA did not propose such an approach and would benefit from additional comment on the issue.[136] EEI did not specify the authority under which it was requesting reconsideration. However, the EPA is denying EEI's petition on this issue because it has not met the CAA section 307(d)(7)(B) standard to demonstrate that it was impracticable to raise this issue during the comment period or that the ground for this objection arose after such period. Moreover, the EPA disagrees with the substance of EEI's request and thus, even if this request had been before the EPA in the rulemaking, it would not have led to a different outcome. That is, EEI's objection is not of central relevance to the Final Rules.

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[134] *Id.,* page 3, par. 4.

[135] Mountain State Energy Holdings, LLC's Petition for Rulemaking and Reconsideration at 1. July 30, 2024. Available in Docket ID No. EPA-HQ-OAR-2023-0072.

[136] See the Edison Electric Institute's Petition for Reconsideration of Discrete Technical Provisions of the 111 Rules, November 4, 2024. Available in Docket ID No. EPA-HQ-OAR-2023-0072.

1. The Final Rules' Inclusion of a Backstop Rate for Certain Compliance Flexibilities was a Logical Outgrowth of the Proposal

First, the Final Rules' inclusion of a backstop rate requirement for existing coal-fired steam generating units using certain types of compliance flexibilities was a logical outgrowth of the Proposed Rules. The EPA proposed to allow states to incorporate rate- or mass-based compliance flexibilities, such as emission trading and averaging, in their state plans, as long as plans demonstrate equivalence to the stringency that would result if each affected EGU was individually achieving its standard of performance, and discussed in detail how states could incorporate either a mass-based or rate-based trading program in a way that preserves the environmental integrity of the BSER. The EPA finalized that, for existing sources using mass-based compliance flexibilities, the state plan must include a unit-specific backstop emission rate, which the EPA determined was necessary to ensure that sources were achieving the objective of the Final Rules to operate more cleanly.

Petitioner's objection to the backstop rate requirement is based in part on its notion that it would be appropriate for a source to comply with a mass-based emission limitation by "significantly lowering its utilization." However, in section XII.E.2.c of the preamble to the Proposed Rules, the EPA discussed in several places the need to ensure that a mass-based compliance approach achieves the same level of emission performance as if each source were achieving its rate-based standard of performance, which is particularly pertinent when affected EGUs are reducing utilization or exiting the source category.[137] This is particularly challenging where, as for this source category, there is significant uncertainty about future fleet composition and utilization beyond the relative near term. To this end, the EPA noted that "[o]ne program design states might employ to ensure that affected EGUs participating in a mass-based trading program continue to meet the level of emission performance prescribed by category-wide, source-specific implementation of the rate-based standards of performance includes regularly adjusting emission budgets to account for sources that cease operations or change their utilization."[138] The Agency discussed other potential methods for ensuring that emission budgets reflect sources' cleaner operation and requested comment on "whether and how a mass-based emission trading program could be designed to ensure equivalent stringency as each participating affected EGU achieving its source-specific standard of performance, given the structure of the proposed subcategories

[137] See, *e.g.*, 88 FR 33374 ("An affected source may also choose to change its operating characteristics in a way that impacts its overall emissions, *e.g.*, by changing its utilization; however, the source is still required to meet its rate-based standard. . . . Although such changes may reduce emissions from the source category, they do not absolve the remaining affected EGUs from the statutory obligation to improve their emission performance consistent with the level that the EPA has determined is achievable through application of the BSER"); 88 FR 33395 ("Critically, if affected EGUs reduce utilization or exit the source category, the remaining affected EGUs face a reduced or eliminated obligation to improve their emission performance. In this case, the emission budget would be established at a level such that the sources would not be collectively meeting the required level of emission performance commensurate with each source achieving its rate-based standard of performance.").
[138] 88 FR 33395.

and their proposed BSERs,"[139] as well as on "approaches or features that could ensure that emission budgets reflect the stringency that would be achieved through unit-specific application of rate-based standards of performance."[140]

Thus, although the EPA did not specifically propose a backstop emission rate in conjunction with mass-based compliance approaches, parties were on notice that the Agency was looking for ways to ensure that sources subject to the Final Rules would operate more cleanly, and that it did not view reduced utilization alone as an appropriate compliance strategy under those Rules given the challenges with accurately projecting future fleet composition and utilization. A backstop emission rate is thus a logical outgrowth of the Proposed Rules. See *Natural Resources Defense Council v. Thomas*, 838 F.2d 1224, 1242 (D.C. Cir. 1988) (finding logical outgrowth was satisfied when "the germ" of the final rule was present at proposal and the primary concern motivating the final rule "was obvious at an early stage"); *Health Insurance Ass'n of America v. Shalala*, 23 F.3d 412, 421 (May 1994) (regulatory provision that appeared for the first time in a final rule was a logical outgrowth when the proposal foreshadowed the provision by presenting the issue it addressed). The EPA is therefore finding that the backstop emission rate was adequately noticed because it was not impracticable to raise an objection during the rulemaking to the notion that compliance through reduced utilization alone does not ensure equivalent stringency.[141] See CAA section 307(d)(7)(B).

Moreover, Petitioner EEI's objections are largely a repetition of the same request and information that was provided to the EPA in comments on the Proposed Rules, which the EPA considered and responded to in the rulemaking. In its comments on the Proposed Rules, EEI requested that the EPA allow states and units to take advantage of the emission reductions possible from decreased utilization through a mass-based approach. Petitioner's Appendix A details mass-based compliance options and hypothetical calculations[142] that are nearly identical

[139] *Id*.
[140] *Id*.
[141] Multiple commenters expressed support for the EPA's proposed position that reduced utilization alone could not ensure equivalent stringency, indicating that parties had adequate notice of and an opportunity to comment on this proposition. See, *e.g.*, Comment submitted by Sierra Club, Earthjustice, Conservation Law Foundation, and Appalachian Voices at 89, August 8, 2023, Document ID No. EPA-HQ-OAR-2023-0072-0813; Comment submitted by Attorneys General of New York, Arizona, California, Connecticut, Hawaii, Illinois, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Mexico, North Carolina, Oregon, Pennsylvania, Rhode Island, Vermont, Washington, Wisconsin, and the District of Columbia, and the Chief Legal Officers of the City and County of Denver, and the Cities of Boulder (CO), Chicago, Los Angeles, New York, and Philadelphia at 81-82, August 8, 2023, Document ID No. EPA-HQ-OAR-2023-0072-0748; Comment submitted by Union of Concerned Scientists at 19-20, August 8, 2023, Document ID No. EPA-HQ-OAR-2023-0072-0643.
[142] See the Edison Electric Institute's Petition for Reconsideration of Discrete Technical Provisions of the 111 Rules, Appendix A at 5-7, November 4, 2024. Available in Docket ID No. EPA-HQ-OAR-2023-0072.

to those provided in Petitioner's comments on the Proposed Rules.[143] The EPA responded to these and other comments on this issue in section X.D of the preamble to the Final Rules "Compliance Flexibilities"[144] and section 11.8.1 and 11.8.2 of the Response to Comments Document, "Mass-based Approaches to Compliance" and "Emissions Trading and Averaging for Compliance."[145]

2. Petitioner's Claims Regarding the Backstop Rate are Not of Central Relevance to the Outcome of the Final Rule

Petitioner EEI's objections are also not of central relevance because the EPA disagrees with Petitioner's suggestion to remove the requirement of a backstop emission rate, as well as with its assertion that a backstop emission rate would be in conflict with a mass-based limitation. Petitioner has offered no explanation for why or how mass-based compliance in the absence of a backstop emission rate would result in equivalent stringency given the concerns discussed in the preambles to the Proposed and Final Rules and summarized below. Thus, the objections regarding the backstop emission rate in EEI's petition for reconsideration are not of central relevance to the outcome of the Final Rules. See CAA section 307(d)(7)(B).

As an initial matter, the EPA's CAA section 111 implementing regulations permit states to include compliance flexibilities, including rate-based and mass-based approaches, in their state plans. The implementing regulations also note that the Agency may place limitations on the use of compliance flexibilities if necessary to protect the environmental outcomes of a particular emission guideline.[146] The backstop emission rate requirement is an example of such a limitation. The EPA found it necessary to include this requirement in the Final Rules for mass-based compliance flexibilities because it believes that there is a high degree of risk that states would not be able to achieve an equivalent level of stringency for these particular sources due to the inherent uncertainty in projecting future utilization. The EPA articulated this challenge and its potential underlying causes in the Proposed Rules: "[p]rojecting affected EGU fleet composition and utilization beyond the relative near term has become increasingly challenging, driven by factors including changes in relative fuel prices and continued rapid improvement in the cost and performance of wind and solar generation, along with new incentives for technology deployment provided by the [Infrastructure Investment and Jobs Act] and the IRA."[147]

[143] Comment submitted by Edison Electric Institute (EEI), Appendix B at 44-45, Document ID No. EPA-HQ-OAR-2023-0072-0772.
[144] 89 FR 39978-90.
[145] U.S. EPA. Response to Comments Document, April 2024, Document ID No. EPA-HQ-OAR-2023-0072-8914.
[146] See 40 CFR 60.21a(f) (definition of "standard of performance" includes provision for such a standard to be "an allowable rate, quantity, or concentration of emissions into the atmosphere"); 88 FR 80480, 80533 (Nov. 17, 2023) ("CAA section 111 does not preclude states from including compliance flexibilities such as trading or averaging for their sources in their state plans, although in particular emission guidelines the EPA may limit those flexibilities if necessary to protect the environmental outcomes of the guidelines").
[147] 88 FR 33395.

These concerns persisted through the public comment period and development of the Final Rules. Specifically for EGUs in the medium-term coal-fired subcategory, the EPA noted in the Final Rules that the "relatively small reduction [of 16 percent from the baseline] is likely to be subsumed by the uncertainty inherent in predicting the utilization of an affected EGU for purposes of determining its mass limit."[148] Again, Petitioner has not provided evidence in its request that this uncertainty regarding future utilization could be eliminated without the use of a backstop emission rate or some other mechanism that would ensure that state plans using a mass-based compliance flexibility achieve equivalent stringency as each affected EGU individually achieving its standard of performance. Moreover, in its request, Petitioner appears to be requesting flexibility for sources to avoid improving its emission performance consistent with the BSER determination of the Final Rules and the statute's broader objective of reducing emissions through cleaner performance.

Further, the Petitioner requested, at a minimum, that the EPA clarify that coal-fired EGUs that permanently cease operation prior to January 1, 2039, and that use "presumptively approved mass- or rate-based approaches" do not require a backstop emission rate. The EPA notes that there is, in fact, no presumptively approvable mass-based approach for such units enumerated in the Final Rules.[149,150] (A presumptively approvable approach to unit-specific mass-based compliance was finalized for existing EGUs in the long-term coal-fired subcategory, including a presumptively approvable methodology for calculating a unit-specific backstop emission rate.[151]) The EPA also notes that the backstop emission rate requirement is only applicable for mass-based compliance flexibility approaches, as rate-based compliance flexibility approaches already, by definition, include a rate-based requirement. The Petitioner's request is thus unclear. Regardless, as explained above, the EPA disagrees with the suggestion to remove the requirement for a backstop emission rate for existing coal-fired EGUs using mass-based flexibilities, including for units that intend to permanently cease operation before January 1, 2039.

Finally, Petitioner stated that the backstop emission rate could be in conflict with achievement of a mass-based emission limitation.[152] The EPA notes that it did not finalize a specific numerical backstop emission rate, only the requirement that one must be applied if participating in a mass-based compliance flexibility. (As previously noted, the EPA provided a presumptively

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[148] 89 FR 39986.
[149] See 89 FR 39986 ("Thus, the EPA is not providing a presumptively approvable approach for unit-specific mass-based compliance for affected EGUs in the medium-term coal-fired subcategory.").
[150] See 89 FR 39988 ("Based on the understanding that a trading program that ensures the level of emission reduction of unit-specific, rate-based compliance under these emission guidelines would necessarily have to be designed with highly conservative utilization assumptions, the EPA is not providing a presumptively approvable approach for mass-based trading.").
[151] 89 FR 39985-86.
[152] See the Edison Electric Institute's Petition for Reconsideration of Discrete Technical Provisions of the 111 Rules, November 4, 2024. Available in Docket ID No. EPA-HQ-OAR-2023-0072.

approvable backstop emission rate methodology for units in the long-term coal-fired subcategory, but states may of course deviate from this approach, subject to EPA state plan approval.) The state thus has the flexibility to determine the appropriate unit-specific backstop emission rate in its plan, provided it could demonstrate that the plan achieves equivalent stringency, while taking into account the need to avoid conflicting with achievement of a mass-based emission limitation. With no rate specified by the EPA, Petitioner's argument that the rate may not be achievable is without a basis or, at the very least, premature.

As one proposed solution to the alleged concern, Petitioner stated that the EPA "should expand the availability of averaging provisions, including the ability to utilize rolling and multi-year averages for compliance, in state plans."[153] Petitioner has not presented any new information nor any explanation in its request as to how rolling and multi-year averages would solve the purported problem of a backstop emission rate conflicting with a mass-based emission limitation or how such mechanisms would assure that state plans achieve equivalent stringency as each affected EGU individually achieving its standard of performance. Thus, the Agency declines to adopt this suggestion.

3. The EPA's Decision to Deny the Petition for Rulemaking on the Grounds Outlined Above is Reasonable under the APA

As shown above, Petitioner EEI does not satisfy either prong of the standard for reconsideration under CAA section 307(d)(7)(B). Although Petitioner did not specify any authority under which it was requesting reconsideration, for the sake of completeness the EPA has considered its request under both the CAA and APA section 553(e). Petitioner has identified no compelling reason for the EPA to reopen or revise the Final Rules. Thus, for the same reasons outlined above, the EPA is denying Petitioner EEI's request regarding the backstop emission rate under APA section 553(e). The EPA's decision is reasonable and entitled to deference.

D. Technical Corrections

Petitioner EEI noted two technical corrections needed to the regulatory text for Subpart TTTTa of Part 60, specifically Equation 3 of section 60.5225a and Table 1.

Petitioner identified an error in the definition of the variable "Intermediate load emissions rate" (ILER) in Equation 3 to Paragraph (a)(3)(ii) of §60.5525a. The EPA acknowledges this inadvertent drafting error in the regulatory text and agrees with Petitioner that this cross reference should be consistent with the emissions rate provided in Table 1. The EPA further acknowledges that the second part of the cross reference is vestige from the proposed new source performance standards (NSPS) which included two phases for intermediate load turbines and should be deleted. This equation is only applicable in the rare scenario in which an intermediate load turbine combusts two or more types of fuel (*e.g.*, natural gas and fuel oil), and the inclusion of the cross reference serves only for convenience; the intermediate load standards in Table 1 are correct.

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153 *Id*.

Petitioner also identified an error in the net and gross emission rates in Table 1, noting that in some cases the net value is higher and in other cases the gross value is higher. The EPA agrees with Petitioner that the emissions standards in Table 1 for Phase 2 baseload combustion turbine standards are in error and should be corrected. The EPA notes that this drafting error, as published in the Code of Federal Regulations (CFR), results in a *less* stringent emission rate, beginning after December 2031, for base load combustion turbines that elect to comply with a gross energy output rate.

Going forward, affected sources should treat these errors as having been corrected as indicated below, though the present action. Any changes to the CFR to incorporate these minor corrections would be ministerial.

The corrected §60.5525a should read:

(ii) For intermediate load combustion turbines:

Equation 3 to Paragraph (a)(3)(ii)

$$CO_2\ emissions\ standard\ = \text{ILER} * [\frac{HIER_A}{HIER_{NG}}]$$

Where:

CO_2 emission standard = the emission standard during the compliance period in units of kg/MWh (or lb/MWh)

ILER = Intermediate load emissions rate for natural gas-fired combustion turbines. ~~520~~ 530 kg/MWh-gross (~~1,150~~ 1,170 lb CO_2/MWh-gross) or ~~530~~ 540 kg CO_2/MWh-net (~~1,160~~ 1,190 lb CO_2/MWh-net) ~~or 450 kg/MWh-gross (1,100 lb CO2/MWh-gross) or 460 kg CO2/MWh-net (1,110 lb CO2/MWh-net) as applicable~~

$HIER_A$ = Heat input-based emissions rate of the actual fuel burned in the combustion turbine (lb CO_2/MMBtu). Not to exceed 69 kg/GJ (160 lb CO_2/MMBtu)

$HIER_{NG}$ = Heat input-based emissions rate of natural gas 50 kg/GJ (120 lb CO_2/MMBtu)

The corrected Table 1 should read:

Table 1 to Subpart TTTTa of Part 60—CO_2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction or Reconstruction After May 23, 2023 (Gross or Net Energy Output-Based Standards Applicable as Approved by the Administrator)

Affected EGU Category	**CO_2 Emission standard**
Base load combustion turbines	For 12-operating month averages beginning before January 2032, 360 to 560 kg CO_2/MWh (800 to 1,250 lb CO_2/MWh) of gross energy

	output; or 370 to 570 kg CO_2/MWh (820 to 1,280 lb CO_2/MWh) of net energy output as determined by the procedures in §60.5525a. For 12-operating month averages beginning after December 2031, 43 to 67 kg CO_2/MWh (~~100~~ 96 to 150 lb CO_2/MWh) of gross energy output; or ~~42~~ 44 to ~~64~~ 68 kg CO_2/MWh (~~97~~ 98 to ~~139~~ 150 lb CO_2/MWh) of net energy output as determined by the procedures in §60.5525a.
Intermediate load combustion turbines	530 to 710 kg CO_2/MWh (1,170 to 1,560 lb CO_2/MWh) of gross energy output; or 540 to 700 kg CO_2/MWh (1,190 to 1,590 lb CO_2/MWh) of net energy output as determined by the procedures in §60.5525a.
Low load combustion turbines	Between 50 to 69 kg CO_2/GJ (120 to 160 lb CO_2/MMBtu) of heat input as determined by the procedures in §60.5525a.

IV. Conclusion

For the reasons outlined above, both MSEH and EEI fail in their petitions to satisfy either of the requirements for mandatory reconsideration under CAA section 307(d)(7)(B). Moreover, neither petitioner has identified any other compelling basis for the EPA to reopen or revise these Final Rules. Thus, the EPA's decision to deny or partially deny both petitions is reasonable and appropriate.

Appendix A: CCS Projects Memorandum

Under the Carbon Pollution Standards rule, new base load turbines operating above 40% annual capacity factor after January 1, 2032 are required to meet an emission rate standard based on application of efficient natural gas-fired combined cycle (NGCC) technology with 90% CCS. The petitioner, Mountain State Energy Holdings (MSEH), claims that new base load NGCC with CCS cannot be built because projects are unable to receive financing due to the CCS-based requirements of the final rule. EPA rejects this claim. MSEH provides mere assertion, and no substantive evidence, tying the rule's CCS requirement to an inability to receive financing. To the contrary, multiple CCS projects for new and existing NGCC units are moving forward. Many of these projects are being developed outside of regulated markets. As documented below, EPA is aware of at least 7 new U.S. NGCC with CCS projects that are in various stages of development, 7 U.S. retrofit NGCC with CSS projects in various stages of development and additional new NGCC with CCS projects under development in Europe and Canada. EPA is also aware of at least 7 vendors who are marketing CCS technologies consistent with the Section 111(b) requirements for new gas-fired turbines.

The record for the Carbon Pollution Standards rule provides numerous examples of new and existing NGCC-CCS projects that are under development, as well as examples of CO_2 pipelines and sequestration infrastructure projects that will help facilitate CCS projects and that are under development. This document updates that record. It provides additional information on the status of new and existing NGCC-CCS projects and other CO_2 capture projects. This document also provides information on multiple technology vendors, including those who are providing CCS technology for those projects. It also provides information on CO_2 pipelines and multiple sequestration infrastructure projects that will help facilitate CCS projects. Finally, the document discusses opportunities to retrofit gas-fired technology to hydrogen, which may provide a useful compliance option for new NGCC units to comply with the applicable standards. Table 1 summarizes NGCC-CCS projects in active development, projects at front-end engineering and design (FEED) study stage, and sequestration enabling projects that are discussed in this document.

Table 1: Summary of states with NGCC-CCS projects and/or sequestration enabling projects in various stages of development that are noted in document.

State	NGCC with CCS project actively under development	NGCC with CCS project in FEED study stage*	Sequestration enabling projects under development
Alabama		Southern Plant Barry	Longleaf Sequestration Hub

California	Sutter (existing) Eastridge (existing) Elk Hills (existing) Net Power-California Resources Corporation (new)	Delta Energy Center	At least 7 hubs under development by California Resources Corporation
Colorado			Part of existing pipeline network between Colorado, New Mexico and Texas
Florida		Tampa Electric Polk	
Iowa			Summit Pipeline
Louisiana	Lake Charles Power Station (existing)		Multiple
Michigan			Lamda Energy Resources
Mississippi		Plant Daniel	Part of existing pipeline network connecting Mississippi
New Mexico			Four Corners Sequestration Hub Part of existing pipeline network between Colorado, New Mexico and Texas
North Dakota			Summit Pipeline
Ohio			Tri-state Buckeye
Oklahoma			Part of existing pipeline network between Kansas and Oklahoma
Pennsylvania			Tri-State Oak Grove
Texas	Calpine Deer Park Energy Center (existing) Calpine Baytown Energy Center (existing)	Panda Sherman	Part of two existing state pipeline networks Multiple third-party sequestration sites under development ExxonMobil offshore (new)

	CPV Basin Ranch (new) Quail Run (existing) NetPower Project Permian (New)		
West Virginia	CPV Shay Energy Center (new)		Tri-State Redbud
Wyoming			Existing pipeline network with Colorado, Montana and Wyoming
State (not announced)	Net Power MISO Project (new) Tristate NGCC Project (new) Exxon (new)		

*These projects have completed or plan to complete FEED studies and are therefore well positioned to install CCS, but have not otherwise made public announcements or commitments to deploy CCS.

I. CO_2 Capture Projects

A large number of CCS projects are in various stages of development or operation,[154, 155] and earlier projects show that CCS is feasible.[156] EPA is aware of at least seven new NGCC with CCS projects and seven existing NGCC with CCS projects under development in the U.S. This section provides more detail on those projects.

A. Sutter Energy Center, California

A retrofit capture CCS project is planned for the existing 550 MW natural gas-fired combined cycle (two combustion turbines) at the Sutter Energy Center in Yuba City, California.[157] The Sutter Decarbonization project will use ION Clean Energy's amine-based solvent technology at a

[154] Clean Air Task Force, "US Carbon Capture Activity Map," *https://www.catf.us/ccsmapus/.*
[155] Global CCS Institute, "Global Status of CCS 2024," November 2024, *https://www.globalccsinstitute.com/wp-content/uploads/2024/11/Global-Status-Report-6-November.pdf*.
[156] Clean Air Task Force, "Carbon capture and storage: What can we learn from the project track record," July 31, 2024, *https://www.catf.us/resource/carbon-capture-storage-what-can-learn-from-project-track-record/*.
[157] Sacramento Municipal Utility District, "Calpine Sutter Decarbonization Project," May 17, 2023, *https://www.smud.org/en/Corporate/Environmental-Leadership/2030-Clean-Energy-Vision/CEV-Landing-Pages/Calpine-presentation*.

capture rate of 95 percent or more. The project expects to complete a FEED study in 2024 and, prior to being selected by DOE for funding award negotiation, planned commercial operation in 2027. Sutter Decarbonization is one of the projects selected by DOE for funding as part of OCED's Carbon Capture Demonstration Projects program.[158] The award was announced August 2024, with up to $270 million of total federal cost share.[159] Class VI well permitting is ongoing with a final decision expected March 2026.[160]

B. Deer Park Energy Center, Texas

The retrofit CO_2 capture project at the Deer Park Energy Center in Deer Park, Texas is designed to capture 95% or more of the flue gas from the five combustion turbines at the 1,200 MW natural gas-fired combined cycle power plant, using technology from Shell CANSOLV.[161] The CO_2 capture project already has an air permit issued for the project, which includes a reduction in the allowable emission limits for NO_X from four of the combustion turbines.[162] The CO_2 capture facility will include two quencher columns, two absorber columns, and one stripping column.

C. Baytown Energy Center, Texas

The Baytown Energy Center in Baytown, Texas is an existing 896 MW natural gas-fired combined cycle cogeneration facility providing heat and power to a nearby industrial facility, while distributing additional electricity to the grid. CCS using Shell's CANSOLV solvent is planned for the equivalent of two of the three combustion turbines at the plant, with a capture rate of 95%. The CO_2 capture facility has an air permit in place, and the permit application provides some details on the process design.[163] The CO_2 capture facility will include two quencher columns, two absorber columns, and one stripping column. To mitigate NO_X emissions, the operation of the SCR systems for the combustion turbines will be adjusted to meet lower NO_X allowable limits—adjustments may include increasing ammonia flow, more frequent SCR repacking and head cleaning, and, possibly, optimization of the ammonia distribution

[158] U.S. DOE, "Carbon Capture Demonstrations Projects Selected and Awarded Projects," *https://www.energy.gov/oced/carbon-capture-demonstration-projects-selections-award-negotiations*.
[159] U.S. DOE, The Office of Clean Energy Demonstrations, "Carbon Capture Demonstration Projects Program. Sutter Decarbonization Program," *https://www.energy.gov/sites/default/files/2024-08/FactSheet_CCDemosAward_Sutter_8.7.24.pdf.*
[160] U.S. EPA, "Current Class VI Projects Under Review at EPA," December 9, 2024, *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa*.
[161] Calpine, "Calpine Carbon Capture: Deer Park, Texas," *https://calpinecarboncapture.com/wp-content/uploads/2023/05/Calpine-Deer-Park-English.pdf.*
[162] Deer Park Energy Center TCEQ Records Online Primary ID 171713; Content ID 6491297: "Pollution Control Project Standard Permit Registration." February 2024.
[163] Baytown Energy Center Air Permit TCEQ Records Online Primary ID 172517; Content ID 6548194: "Pollution Control Project Standard Permit Registration." April 2023.

system. Captured CO_2 will be transported and stored at sites along the U.S. Gulf Coast. The Baytown CO_2 capture project is one of the projects selected by DOE for funding as part of OCED's Carbon Capture Demonstration Projects program[164] and the cost sharing agreement was announced July 2024[165] with a total federal cost share of up to $270 million.[166, 167]

D. Lake Charles Power Station, Louisiana

Entergy Services, LLC is developing a CCS retrofit at the 994 MW Lake Charles Power Station, Westlake, Louisiana. The project was awarded funding by DOE for a FEED study, which began January 2024, for 95% capture using MHI's KS-21 solvent technology.[168] A separate FEED study is being developed based on Honeywell's capture technology.[169] Crescent Midstream will lead development of the CCS project, in collaboration with Entergy and SAMSUNG E&A.[170] Meta has also committed to help fund the project.[171] Construction is planned to start in 2026[172]

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[164] U.S. DOE, "Carbon Capture Demonstration Projects Selections for Award Negotiations. Baytown Carbon Capture and Storage Project," *https://www.energy.gov/oced/carbon-capture-demonstration-projects-selections-award-negotiations.*

[165] Calpine, "Calpine Announces Execution of Full-Scale Demonstration Project Cost Sharing Agreement with DOE for Baytown Decarbonization Project," July 3, 2024, *https://www.calpine.com/calpine-announces-execution-of-full-scale-demonstration-project-cost-sharing-agreement-with-doe-for-baytown-decarbonization-project/.*

[166] U.S. DOE Office of Clean Energy Demonstrations, "Carbon Capture Demonstration Projects Program. Baytown Carbon Capture and Storage Project," *https://www.energy.gov/oced/articles/award-wednesdays-july-3-2024*.

[167] U.S. DOE Office of Clean Energy Demonstrations, "Baytown Carbon Capture and Storage Project," *https://www.energy.gov/sites/default/files/202407 /Baytown%20CC%20and%20Storage%20Factsheet_072324.pdf.*

[168] U.S. DOE Office of Clean Energy Demonstrations, "Carbon Capture Demonstration Projects Program. Front-End Engineering Design (FEED) Studies," *https://www.energy.gov/sites/default/files/2024-01/OCED_CCFEEDs_AwardeeFactSheet_EntergyServicesLakeCharles_1.5.2024_v3.pdf.*

[169] Power Magazine, "Billions in Federal Funding Earmarked for Power Plant CCS Projects: Here's a Snapshot," October 2, 2024, *https://www.powermag.com/billions-in-federal-funding-earmarked-for-power-plant-ccs-projects-heres-a-snapshot/.*

[170]Crescent Midstream, "Crescent Midstream Selected to Develop an Integrated Carbon Capture Solution for Entergy Louisiana Natural Gas Power Plant," September 17, 2024, *https://crescentmidstream.com/news/crescent-midstream-selected-develop-integrated-carbon-capture-solution-entergy-louisiana*.

[171] Entergy Newsroom, "Entergy Louisiana to power Meta's data center in Richland Parish," December 5, 2024, *https://www.entergynewsroom.com/news/entergy-louisiana-power-meta-s-data-center-in-richland-parish/.*

[172] KPLC TV, "Entergy, Crescent Midstream collaborating on carbon capture project," September 23, 2024, *https://www.kplctv.com/2024/09/23/entergy-crescent-midstream-collaborating-carbon-capture-project/.*

and the project is expected to be completed in 2028 and will capture up to 3 million metric tons of CO_2 per year.[173]

E. Elk Hills Cogeneration, California

Development of CCS from the Elk Hills Cogeneration facility continues to progress. The Elk Hills Cogeneration facility is a 550 MW facility near Tupman, Kern County, California. A DOE funded FEED study for 90% capture using Fluor's Econamine FG Plus^{SM} solvent technology was completed in 2022.[174] Capture at the Elk Hills plant is associated with the California Resources Corporation's Carbon TerraVault business, which aims to develop carbon capture, transport, and sequestration services in the region around Kern County.[175] On December 30, 2024, EPA issued four Class VI well permits for Carbon TerraVault that will store CO_2 from sources in Kern County, including the CO_2 from Elk Hills Cogeneration.[176]

F. Eastridge Cogeneration, California

CCS is planned for Chevron's Eastridge Cogeneration facility.[177] The CO_2 capture process will use Fluor's Econamine FG Plus^{SM} solvent technology to reduce emissions by 95%.[178] A Class VI permit for the project was filed in December 2023.[179]

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[173] Reuters, "Carlyle-backed Crescent Midstream to build carbon capture and storage unit in Louisiana," September 20, 2024, *https://www.reuters.com/sustainability/climate-energy/carlyle-backed-crescent-midstream-build-carbon-capture-storage-unit-louisiana-2024-09-20/*.
[174] U.S. DOE. Office of Scientific and Technical Information, "Front-End Engineering Design Study for Retrofit Post-Combustion Carbon Capture on a Natural Gas Combined Cycle Power Plant," July 11, 2022, *https://www.osti.gov/biblio/1867616*.
[175] California Resources Corporation. Carbon Terravault, "Carbon Capture and Storage," *https://s202.q4cdn.com/682408967/files/doc_downloads/2023/12/calcapture_infographic_english_12-20-23.pdf*.
[176] U.S. EPA, "EPA issues first ever underground injection permits for carbon sequestration in California," December 30, 2024, *https://www.epa.gov/newsreleases/epa-issues-first-ever-underground-injection-permits-carbon-sequestration-california.*
[177] Chevron, "Chevron carbon capture and storage initiative in san joaquin valley," November 16, 2022, *https://www.chevron.com/-/media/chevron/stories/documents/eastridge-sjv-fact-sheet.pdf*.
[178] Fluor, "Fluors Econamine FG Plus Carbon Capture Technology Selected to Reduce CO2 Emissions at Chevron Facility," February 6, 2024, *https://newsroom.fluor.com/news-releases/news-details/2024/Fluors-Econamine-FG-PlusSM-Carbon-Capture-Technology-Selected-to-Reduce-CO2-Emissions-at-Chevron-Facility/default.aspx*.
[179] U.S. Environmental Protection Agency, "UIC Permits in EPA's Pacific Southwest (Region 9)," *https://www.epa.gov/uic/r9-uic-permits.*

G. Quail Run, Texas

Quail Run Carbon has submitted a permit application to retrofit the existing 550 MW Quail Run Energy Center combined cycle facility in Odessa, Texas with a carbon capture system with a 95-percent design capture rate.[180]

H. CPV Shay Energy Center, West Virginia

Competitive Power Ventures (CPV) are developing a new 2,060 MW NGCC power plant with carbon capture in Doddridge County, West Virginia.[181] The West Virginia Public Utility Commission approved the siting certificate for the power plant in April 2024. The beginning of construction is planned for the fourth quarter of 2025.[182]

I. CPV Basin Ranch, Texas

Competitive Power Ventures (CPV) Basin Ranch Energy Center is a new 1,320 megawatt (MW) natural gas-fired combined cycle unit with CCS to be located in Ward County, Texas. According to a January 2024 permit application submitted by the owner, construction is planned to commence in early 2025; commercial operation of the generating facility is expected to begin in early 2028; and the carbon capture and storage system is expected to come online in early 2029.[183] The project developer has not publicly announced a CCS capture efficiency for the project. The Public Utility Commission of Texas advanced the project to the next stage of the Texas Energy Fund process in August 2024.[184]

J. Net Power Project Permian

Net Power is planning a new 300 MW natural gas-fired combustion turbine plant in the Permian Region of Texas.[185] A FEED study was planned to be completed by the end of 2024. Net Power has submitted an interconnection request to the Electric Reliability Council of Texas, and has

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[180] Quail Run Carbon Project Application, February 17, 2022, *https://assets.comptroller.texas.gov/ch313/1701/1701-ector-quail-app.pdf*.
[181] Competitive Power Ventures, "CPV Shay Energy Center," *https://www.cpv.com/our-projects/cpv-shay-energy-center/*.
[182] The Parkersburg News and Sentinel, "West Virginia officials approve construction of a gas turbine power plant," April 30, 2024. *https://www.newsandsentinel.com/news/business/2024/04/west-virginia-officials-approve-construction-of-gas-turbine-power-plant/*.
[183] Texas Commission on Environmental Quality, "Notice of Receipt of Application and Intent to Obtain Air Permit (NORI) for CPV Basin Ranch Holdings, LLC," January 24, 2024, *https://www.tceq.texas.gov/downloads/permitting/air/bilingual/pending-permit- notices/175063-nori-english.PDF*.
[184] Competitive Power Ventures, "Public Utility Commission of Texas Advances CPVs Project in Texas Energy Fund Process," August 29, 2024, *https://www.cpv.com/2024/08/29/public-utility-commission-of-texas-advances-cpvs-project-in-texas-energy-fund-process/*.
[185] Net Power Inc, "First Utility Scale Project," *https://netpower.com/first-utility-scale-project/*.

ordered long lead time components. See 89 Fed. Reg. at 39,814. Net Power is planning to start operation between the second half of 2027 and first half of 2028.[186, 187]

K. Net Power and California Resources Corporation

Net Power and California Resources Corporation announced a Memorandum of Understanding to develop up to 1 GW of generating capacity with CCS in Northern California.[188]

L. Net Power MISO Project

Net Power has submitted an interconnect request in April 2024 for a facility in the MISO market.[189] A Class VI permit has been submitted by the sequestration partner.[190]

M. Exxon Mobil Data Centers

Exxon Mobil is planning a 1.5 GW natural gas-fired power plant with 90% carbon capture to supply electricity to a data center. The plant will be located near Exxon's network of existing CO_2 pipelines.[191] The plant would be ready for operation in the next five years. Exxon Mobil does not plan to have the plant connected to the electric grid.[192]

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[186] Net Power Inc, "Net Power Reports Third Quarter 2024 Results and Provides Business Update," November 11, 2024, *https://ir.netpower.com/resources/press-releases/detail/34/net-power-reports-third-quarter-2024-results-and-provides*.

[187]Net Power, "Third Quarter 2024 Results," November 11, 2024, *https://d1io3yog0oux5.cloudfront.net/_5c7ea8de9b02f532a7eeefd6caf2a268/netpower/db/3583/33213/pdf/Q3+2024+Earnings+Presentation_11.11.2024.pdf*.

[188] Net Power Inc, "Carbon TerraVault and Net Power Sign MOU to Develop Low Carbon Reliable Power Solutions in California," December 9, 2024, *https://netpower.com/press-releases/carbon-terravault-and-net-power-sign-mou-to-develop-low-carbon-reliable-power-solutions-in-california/; https://www.businesswire.com/news/home/20241209553590/en/Carbon-TerraVault-and-Net-Power-Sign-MOU-to-Develop-Low-Carbon-Reliable-Power-Solutions-in-California*.

[189] Net Power, "NET Power Reports First Quarter 2024 Results and Provides Business Update," May 13, 2024, *https://ir.netpower.com/resources/press-releases/detail/30/net-power-reports-first-quarter-2024-results-and-provides*.

[190] Net Power, "Third Quarter 2024 Results," *https://d1io3yog0oux5.cloudfront.net/_5c7ea8de9b02f532a7eeefd6caf2a268/netpower/db/3583/33213/pdf/Q3+2024+Earnings+Presentation_11.11.2024.pdf*.

[191] Carbon Herald: Carbon Removal Capture and Markets, "Exxon Wants to Satiate Power hungry Data Centers with Natural Gas and Carbon Capture," December 12, 2024, *https://carbonherald.com/exxon-mobil-power-data-centers-natural-gas-carbon-capture/.*

[192] Power Magazine, "ExxonMobil Planning Large Gas Fired Plant to Serve Data Centers," December 11, 2024, *https://www.powermag.com/exxonmobil-planning-large-gas-fired-plant-to-serve-data-centers/.*

N. Tri-state Generation

Tri-State Generation has announced plans to build a 290 MW natural gas-fired combined cycle facility by 2028 and install CCS by 2031.[193]

O. International Projects

Numerous international CCS projects including capture on post-combustion sources are in various stages of development or operation, as reported and summarized in the Global CCS Institute's *Global Status of CCS 2024* report.[194]

Among these is the Net Zero Teesside Power (NZT Power) project in the United Kingdom. The project will capture CO_2 from a new natural gas-fired combined cycle unit. The project achieved financial close (final investment decision) in December 2024. Construction is planned to start in mid-2025 with operation in 2028.[195, 196] Another project in the United Kingdom, Humber Zero, will capture 95% of the CO2 from two natural gas-fired turbines at the VPI Immingham Combined Heat and Power Plant.[197] In Norway, SLB Capturi (a joint venture between SLB and Aker Carbon Capture) will deliver solvent-based CO_2 capture equipment in Q4 2025 for application at Ørsted's wood chip-fired Asnæs Power Station and the Avedøre Power Station's straw-fired boiler. The total capture capacity is 500,000 metric tons per year.[198]

P. Industrial Projects

Solvent-based CO_2 capture projects in other industries continue to progress. For example, SLB Capturi completed construction on December 2, 2024, of what it describes as the "world's first industrial-scale carbon capture plant at a cement facility." The capture plant will reduce emissions by up to 400,000 metric tons of CO_2 annually at Heidelberg Materials' cement plant in

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[193] Tri-State Generation and Transmission Association, Inc, "Tri-State accelerates clean energy transition and bolsters electric system reliability," Dec. 1, 2023, *https://tristate.coop/tri-state-accelerates-clean-energy-transition*.
[194] Global CCS Institute, "Global Status of CCS 2024: Collaborating for a Net-Zero Future," November 2024, *https://www.globalccsinstitute.com/wp-content/uploads/2024/11/Global-Status-Report-6-November.pdf*.
[195] GE Vernova, "Technip Energies and GE Vernova Awarded a major contract for the Net Zero Teesside Power project which aims to be the world's first gas-fired power station with carbon capture and storage," December 11, 2024, *https://www.gevernova.com/news/press-releases/technip-energies-ge-vernova-awarded-major-contract-net-zero-teesside-power-project*.
[196] NZT Power and Net Zero Teesside, "Greenlight for Net Zero Teesside Power," December 10, 2024, *https://www.netzeroteesside.co.uk/news/greenlight-for-net-zero-teesside-power/*.
[197] HumberZero, "The Technology. Carbon Capture," *https://humberzero.co.uk/humber-zero-capturing-carbon*.
[198] SLB Capturi, "Orsted Kalundborg CCS," *https://capturi.slb.com/projects/kalundborg-ccs*.

Brevik, Norway.[199] In addition, Heidelberg Materials North America is developing a CCS project at its facility in Edmonton, Alberta, Canada. The project will capture 1 million metric tons of CO_2 per year. It was announced in February 2024 that Technip Energies has been selected to produce a FEED study for the project based on Shell's CANSOLV® technology.[200] Heidelberg Materials North America anticipates operation of the capture plant to begin in late 2026.

The DOE's Office of Clean Energy Demonstration has selected or awarded a number of industrial projects for funding.[201] This includes a net-zero (including CO_2 capture) project at National Cement Company of California's Lebec, California plant.[202] Another project at Heidelberg Materials US's Mitchell, Indiana cement plant will capture 95% of CO_2 emissions.[203]

Q. Projects with Completed or On-going FEED studies

There are several domestic NGCC projects with completed or on-going FEED studies. These have been summarized in the record previously at 89 Fed. Reg. at 39927/3 - 39929/1, as well as in the Greenhouse Gas Mitigation Measures for Steam Generating Units TSD, page 58, table 13. These include projects at Calpine's Delta Energy Center in California,[204] TECO's Polk Unit 2 in

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[199] SLB Capturi, "SLB Capturi completes construction of the world's first industrial-scale carbon capture plant at a cement facility," December 2, 2024, *https://capturi.slb.com/resources/news/slb-capturi-completes-construction-of-the-worlds-first-industrial-scale-carbon-capture-plant*.

[200] Heidelberg Materials, "Heidelberg Materials North America Announces Latest Step in Edmonton CCUS Project," February 15, 2024, *https://www.heidelbergmaterials.us/home/news/news/2024/02/15/heidelberg-materials-north-america-announces-latest-step-in-edmonton-ccus-project*.

[201] U.S. DOE Office of Clean Energy Demonstrations, "Industrial Demonstrations Program Selected and Awarded Projects," *https://www.energy.gov/oced/industrial-demonstrations-program-selected-and-awarded-projects*.

[202] U.S. DOE Office of Clean Energy Demonstrations, "Industrial Demonstrations Program Selected and Awarded Projects. Lebec Net Zero Project," *https://www.energy.gov/sites/default/files/2024-12/Factsheet_IDP_NCC-CA_PhaseOne_12.4.24.pdf*.

[203] U.S. DOE Office of Clean Energy Demonstrations, "Industrial Demonstrations Program. Mitchell Cement Plant Decarbonization Project," *https://www.energy.gov/sites/default/files/2024-08/Factsheet_IDP_Heidelberg_8.14.24FINAL.pdf*.

[204] Ion Clean Energy, "Project Delta," August 28, 2023, *https://netl.doe.gov/sites/default/files/netl-file/23CM_PSCC28_Awtry.pdf*.

Florida,[205] Southern Company's Plant Barry in Alabama,[206] Panda's Sherman plant in Texas,[207] and Plant Daniel in Mississippi.[208]

R. Technology Providers

Numerous companies have developed carbon capture technology and have confirmed that the technology is effective on fossil fuel-fired electricity generating plants and captures at least 90%, and in many cases more than 95%, of CO_2.

1. Shell

Shell has decades of experience in CO_2 capture systems. Shell notes that "[c]apturing and safely storing carbon is an option that's available now."[209] Shell has developed the CANSOLV® CO_2 capture system for CO_2 capture from post-combustion flue gas: "Shell Catalysts & Technologies has developed a CO_2 capture technology utilizing a regenerable amine that offers cutting-edge performance, including low parasitic energy consumption, fast kinetics and extremely low volatility. The technology allows for the capture of CO_2 from flue gas."[210] Shell further notes, "Moreover, the technology has been designed for reliability through its highly flexible turn-up and turndown capacity."[211] Shell CANSOLV® can achieve over 90% of capture: "Over 90% of the CO_2 in exhaust gases can be effectively and economically removed through the implementation of Shell's carbon capture technology."[212] Shell also notes, "Systems can be guaranteed for bulk CO_2 removal of over 90%."[213] The Shell CANSOLV® capture system has

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205 TECO Tampa Electric, "Polk Power Station Natural Gas Combined Cycle Carbon Capture Front-End Engineering and Design Study," *https://netl.doe.gov/sites/default/files/netl-file/23CM_PSCC28_Dilport.pdf*.
206 U.S. DOE Office of Scientific and Technical Information, "Retrofittable Advanced Combined Cycle Integration for Flexible Decarbonized Generation," June 28, 2024, *https://www.osti.gov/biblio/2377996*.
207 U.S. DOE Office of Scientific and Technical Information, "Front-End Engineering Design (FEED) Study for a Carbon Capture Plant Retrofit to a Natural Gas-Fired Gas Turbine Combined Cycle Power Plant (2x2x1 Duct-Fired 758-MWe Facility with F Class Turbines)," *https://www.osti.gov/biblio/1836563*.
208 U.S. DOE Office of Scientific and Technical Information, "Front End Engineering Design of Linde-BASF Advanced Post-Combustion CO2 Capture Technology at a Southern Company Natural Gas-Fired Power Plant (Final Scientific/Technical Report)," September 30, 2022, *https://www.osti.gov/biblio/1890156*.
209 Shell Global, "Carbon Capture and Storage," *https://www.shell.com/energy-and-innovation/carbon-capture-and-storage.html#iframe=L3dlYmFwcHMvQ0NTX0dsb2JlLw*.
210 Shell Global, "CANSOLV® CO_2 Capture System," *https://www.shell.com/business-customers/catalysts-technologies/licensed-technologies/emissions-standards/tail-gas-treatment-unit/cansolv-co2.html*.
211 Shell Catalysts & Technologies, "Shell CANSOLV® CO_2 Capture System," *https://catalysts.shell.com/en/Cansolv-co2-fact-sheet*.
212 *Id*.
213 *Id*.

been commercially deployed at Boundary Dam Unit 3, and is planned for use at Calpine's Baytown and Deer Park Energy Center facilities. It is also planned for use at the Net Zero Teesside Power (NZT Power) project in the United Kingdom.[214]

2. MHI

Mitsubishi Heavy Industries (MHI) in collaboration with Kansai Electric Power Co., Inc. began developing a solvent-based capture process (the KM CDR Process™) using the KS-1™ solvent in 1990.[215] MHI describes the solvent in terms of its extensive experience of commercial application, "KS-1™"a solvent whose high reliability has been confirmed by a track record of deliveries to 15 commercial plants worldwide."[216] Notable applications of KS-1™ and the KM-CDR Process™ include applications at Plant Barry and Petra Nova. Previously, MHI has achieved capture rates of greater than 90% over long periods and at full scale at the Petra Nova project where the KS-1™ solvent was used.[217] MHI has further improved on the original process and solvent by making available the Advanced KM CDR Process™ using the KS-21™ solvent. From MHI: "Commercialization of KS-21™ solvent was completed following demonstration testing in 2021 at the Technology Centre Mongstad in Norway, one of the world's largest carbon capture demonstration facilities."[218] MHI has demonstrated achievable CO_2 capture rates of 95 to 98% using both the KS-1™ and KS-21™ solvent at the Technology Centre Mongstad (TCM).[219] Higher capture rates under modified conditions were also measured, "In addition, in testing conducted under modified operating conditions, the KS-21™ solvent delivered an industry-leading carbon capture rate was 99.8% and demonstrated the successful recovery of CO_2 from flue gas of lower concentration than the CO_2 contained in the atmosphere."[220]

3. Linde-BASF

Linde engineering in partnership with BASF has made available BASF's OASE® blue amine solvent technology for post-combustion CO_2 capture. Linde notes their experience: "We have longstanding experience in the design and construction of chemical wash processes, providing the necessary amine-based solvent systems and the CO_2 compression, drying and purification

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[214] Technip Energies, "Achieving at scale for Net Zero Teesside Power," *https://www.ten.com/en/case-studies/achieving-scale-net-zero-teesside-power.*
[215] Mitsubishi Heavy Industries, "CO_2 Capture Technology: CO_2 Capture Process," *https://www.mhi.com/products/engineering/co2plants_process.html*.
[216] *Id*.
[217] Note: Petra Nova is an EPAct05-assisted project.; U.S. Department of Energy, National Energy Technology Laboratory, "W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report (March 2020)," *https://www.osti.gov/servlets/purl/1608572*.
[218] *Id*.
[219] Mitsubishi Heavy Industries, "Mitsubishi Heavy Industries Engineering Successfully Completes Testing of New KS-21™ Solvent for CO_2 Capture," *https://www.mhi.com/news/211019.html*.
[220] *Id*.

system."[221] Linde also notes that "[t]he BASF OASE® process is used successfully in more than 400 plants worldwide to scrub natural, synthesis and other industrial gases."[222] The OASE® blue technology has been successfully piloted at RWE Power, Niederaussem, Germany, a coal-fired power plant (from 2009 through 2017; 55,000 operating hours) and the National Center for Carbon Capture in Wilsonville, Alabama (January 2015 through January 2016; 3,200 operating hours). Based on the demonstrated performance, Linde concludes that "post-combustion carbon capture] plants combining Linde's engineering skills and BASF's OASE® blue solvent technology are now commercially available for a wide range of applications."[223] Linde and BASF have demonstrated capture rates over 90% and operating availability[224] rates of more than 97% during 55,000 hours of operation.

4. Fluor

Fluor provides a solvent technology (Econamine FG Plus) and EPC services for CO_2 capture. Fluor describes its technology as proven, noting that, "Proven technology. Fluor Econamine FG Plus technology is a propriety carbon capture solution with more than 30 licensed plants and more than 30 years of operation."[225] Fluor further notes, "The technology builds on Fluor's more than 400 CO_2 removal units in natural gas and synthesis gas processing."[226] Fluor further states, "Fluor is a global leader in CO_2 capture […] with long-term commercial operating experience in CO_2 recovery from flue gas." On the status of Econamine FG Plus, Fluor notes that the "[the] Technology [is] commercially proven on natural gas, coal, and fuel oil flue gases," and further notes that "[o]perating experience includes using steam reformers, gas turbines, gas engines, and coal/natural gas boilers."

5. ION Clean Energy

ION Clean Energy is a company focused on post-combustion carbon capture founded in 2008. ION's ICE-21 solvent has been demonstrated at NCCC and TCM Norway.[227] ION has demonstrated capture rates of 98% using the ICE-21 solvent. ION's third generation solvent,

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[221] Linde Engineering, "Post Combustion Capture (PCC)," *https://www.linde-engineering.com/en/process-plants/co2-plants/carbon-capture/post-combustion-capture/index.html*.
[222] Linde and BASF, "Carbon capture storage and utilisation," *https://assets.linde.com/-/media/global/corporate/corporate/documents/clean-energy/carbon-capture-storage-utilisation-linde-basf_tcm19-462558.pdf*.
[223] *Id*.
[224] Operating availability is the percent of time that the CO_2 capture equipment is available relative to its planned operation.
[225] Fluor, "Comprehensive Solutions for Carbon Capture," *https://www.fluor.com/client-markets/energy/production/carbon-capture*.
[226] Fluor, "Econamine FG Plus[SM],"
https://www.fluor.com/sitecollectiondocuments/qr/econamine-fg-plus-brochure.pdf.
[227] ION Clean Energy, "Company," *https://www.ioncleanenergy.com/company*.

ICE-31, has been demonstrated at NCCC[228] and tests have been completed at TCM Norway where capture rates over 99% were achieved.[229] ION and Calpine also commissioned a 10 ton-per-day large-scale pilot facility at Calpine's Los Medanos Energy Center.,[230] The ION technology is also planned for use at Calpine's Sutter facility.

6. MTR

The CO_2 capture-based best system of emission reduction (BSER) in the Carbon Pollution Standards final rules is based on amine solvent technology. However, other technologies can remove CO_2 from the post-combustion exhaust. Membrane Technology Research (MTR) utilizes a membrane technology to capture CO_2 at rates up to 90% from natural gas-fired power plants.[231] An advantage of membrane separation processes is that they avoid the use of a solvent, have reduced water consumption, and have no heating demands. MTR recently completed construction of a large-scale pilot facility in Gillette, Wyoming. The facility will capture 150 metric tons per day from Basin Electric's coal-fired Dry Fork Station.[232]

7. Net Power

Net Power uses a pre-combustion CCS process based on combusting natural gas with pure oxygen, creating CO_2 and water.[233] The technology has been demonstrated at a 50 MW facility in Texas that between 2018 and 2022 recorded over 1500 hours of operation.[234] The test facility is currently being used to validate a new turbo-expander which will be used in the first full scale utility project.[235] Net Power is in advanced stages of deployment of their first full scale project in Texas. They report that the FEED study was scheduled to be completed by the end of 2024 and

[228] 16th International Conference on Greenhouse Gas Control Technologies (GHGT-16), "Demonstration of ION's Novel CO2 Capture Solvent (ICE-31) with High Performance and Exceptional Stability through Field Testing at NCCC's PSTU with Coal and NGCC Gas," *https://cdn.prod.website-files.com/640fee7f8b52071e1af90f38/645523b38ac0542438b7e7f8_%40725%20-%20GHGT-16-Apollo-Final.pdf*.

[229] National Energy Technology Laboratory (NETL), "Preliminary Techno-Economic Assessment of High-Efficiency Post Combustion Carbon Capture from NGCC," *https://netl.doe.gov/sites/default/files/netl-file/24CM/24CM_PSCC_7_WLi.pdf*.

[230] Calpine, "Project Enterprise at Calpine LMEC," *https://calpineca.com/wp-content/uploads/2023/08/Calpine-CCUS-Enterprise-.pdf*.

[231] MTR, "Natural Gas Fired Power Plants," *https://mtrccs.com/natural-gas-fired-power-plants/*.

[232] Carbon Herald, "MTR Completes World's Largest Membrane Carbon Capture Testing Facility," December 17, 2024, *https://carbonherald.com/mtr-completes-worlds-largest-membrane-carbon-capture-testing-facility/*.

[233] NET Power, "Technology: The NET Power Cycle," *https://netpower.com/technology/*.

[234] NET Power, "La Porte Test Facility," *https://netpower.com/la-porte-test-facility/*.

[235] NET Power, "Net Power Reports Third Quarter 2024 Results and Provides Business Update," November 11, 2024, *https://ir.netpower.com/resources/press-releases/detail/34/net-power-reports-third-quarter-2024-results-and-provides*.

that they have ordered multiple long lead time pieces of equipment for the project.[236] Net Power is making progress in developing multiple other projects in the U.S. and Canada.[237] One market that Net Power is pursuing is the data center market. By optimizing the size of the air separation unit and the oxygen storage tank, a Net Power plant can provide both baseload power to the data center and peaking power to the grid.[238]

II. CO_2 Pipelines

The BSER in the Final Rules is premised on source-to-sink (point-to-point) pipelines, *i.e.*, an individual CO_2 pipeline for each affected power plant. New sources can also be preferentially sited in proximity to storage locations. While the BSER is not dependent on a national or regional trunkline network, existing pipeline infrastructure and on-going projects will further enable deployment of CCS. The Final Rules described the over 5,000 miles of existing CO_2 pipelines, across multiple states. States with existing pipelines include Colorado, Kansas, Mississippi, New Mexico, Oklahoma, Texas and Wyoming. The Final Rules also describe additional pipeline development projects. *See* 89 FR 39855-39864.

Since the promulgation of the Final Rules, further progress has been made in pipeline development. Development of the multi-state Summit pipeline project in Iowa, Minnesota, Nebraska, North Dakota and South Dakota continues to progress, and the project has recently received a series of permit approvals. The Iowa Utilities Board approved a permit for 688 miles of the pipeline on June 25, 2024.[239] North Dakota regulators approved a route permit[240] for 333 miles of the pipeline on November 15, 2024, after previously denying the permit in 2023.[241] The North Dakota approval came after Summit made changes to its proposed pipeline route.[242] Summit had also applied for a permit in South Dakota that was denied by the South Dakota Public Utility Commission in September 2023, but Summit resubmitted the permit application on

[236] *Id.*
[237] *Id.*
[238] Net Power, "Third Quarter Results," November 11, 2024, Slide 6 - *https://d1io3yog0oux5.cloudfront.net/_97bc0f8d451b236a5101cec315834d7a/netpower/db/3606/33210/presentation/Q3+2024+Earnings+Presentation_11.11.2024.pdf.*
[239] Summit Carbon Solutions, "Summit Carbon Solutions Granted Approval by IUB for CO2 Pipeline," June 25, 2024, *https://summitcarbonsolutions.com/summit-carbon-solutions-granted-approval-by-iub-for-co2-pipeline/.*
[240] Summit Carbon Solutions, "Summit Carbon Solutions Secures North Dakota Pipeline Permit," November 15, 2024, *https://summitcarbonsolutions.com/summit-carbon-solutions-secures-north-dakota-pipeline-permit/.*
[241] Yahoo! News, "North Dakota approves Summit carbon pipeline route," November 15, 2024, *https://www.yahoo.com/news/north-dakota-approves-summit-carbon-165208482.html.*
[242] North Dakota Monitor, "North Dakota approves Summit carbon pipeline route," November 15, 2024, *https://northdakotamonitor.com/2024/11/15/north-dakota-approves-summit-carbon-pipeline-route/.*

November 19, 2024 with route changes intended to address the Commission's concerns.[243] The Minnesota Public Utilities Commission granted a permit for a 28 mile route on December 12, 2024.[244] At the same time, Summit also announced it had received three Class VI well permits from the North Dakota Industrial Commission.[245]

Other companies are also making progress in CO_2 pipeline development. In October 2024, CapturePoint announced potential plans to expand its current 150 miles of CO_2 pipeline in Texas and Arkansas to approximately 500 miles.[246] Furthermore, Occidental announced on October 28, 2024 that it had partnered with Enterprise Products Partners to develop a network of new CO_2 pipelines in Texas. The company says that the pipelines will transport third party captured CO_2 to a sequestration hub.[247]

III. CO_2 Sequestration and CCS Hubs

While the BSER is premised on a separate sequestration site being developed for each power plant, CO_2 sequestration infrastructure continues to progress that would further enable CCS deployment for the power sector. Approval of Class VI underground injection control (UIC) wells continues to progress.[248] In the Carbon Pollution Standards rule, the EPA notes that, as of March 15, 2024, the agency had 130 Class VI well permit applications under review and had issued eight final permit decisions.[249] The Class VI UIC permitting program continues to develop additional tools and resources to support the permitting process, and has received a number of new applications. As of January 3, 2025, the EPA has 163 Class VI UIC well permit applications

[243] North Dakota Monitor, "Carbon pipeline company reapplies for South Dakota permit," November 19, 2024, *https://northdakotamonitor.com/2024/11/19/carbon-pipeline-company-reapplies-for-south-dakota-permit/.*
[244] Summit Carbon Solutions, "Summit Carbon Solutions Receives Pipeline Permit From Minnesota PUC," December 12, 2024, *https://summitcarbonsolutions.com/summit-carbon-solutions-receives-pipeline-permit-from-minnesota-puc/.*
[245] Summit Carbon Solutions, "Summit Carbon Solutions Secures Sequestration Permits from North Dakota Industrial Commission," December 12, 2024, *https://summitcarbonsolutions.com/summit-carbon-solutions-secures-sequestration-permits-from-north-dakota-industrial-commission/.*
[246] E&E News, "Louisiana CO2 pipeline project may triple in size," October 8, 2024, *https://www.eenews.net/articles/louisiana-co2-pipeline-project-may-triple-in-size/.*
[247] S&P Global, "Occidental to build network of CO2 pipelines in southeast Texas," October 28, 2024, *https://www.spglobal.com/commodity-insights/en/news-research/latest-news/energy-transition/102824-occidental-to-build-network-of-co2-pipelines-in-southeast-texas.*
[248] U.S. Environmental Protection Agency, "Underground Injection Control (UIC) Class VI Permit Tracker," January 3, 2025, *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.*
[249] 89 Fed. Reg. at 39870/2. Four of these final permit decisions expired after they were issued and are not reflected in EPA's Underground Injection Control (UIC) Class VI Permit Tracker. *See https://www.epa.gov/uic/current-class-vi-projects-under-review-epa* (noting that only active Class VI permits are included in the "Final Permit Decisions Issued" count).

under review. The EPA has issued a total of 12 final permit decisions[250] and an additional three final permit decisions are being prepared.[251] The vast majority of the permit applications under review (151)—including approximately 80 percent of the 45 applications received since March 15, 2024—have already been deemed complete and have moved to the technical review phase of the permitting process.[252]

States have also applied for Class VI well primary enforcement responsibility (primacy). States with Class VI primacy currently include Louisiana, North Dakota, and Wyoming.[253] Arizona submitted an application to EPA seeking Class VI primacy on February 16, 2024.[254] On November 27, 2024, the EPA proposed approval of West Virginia's Class VI primacy application (see 89 FR 93538).[255] Other states (Alaska, Mississippi, Texas, Utah, Alabama, and Colorado) are in the pre-application phase.[256]

Several CCS hubs, focused on sequestration of CO_2 from multiple sources, are in various stages of development. In California, the California Resources Corporation has plans for seven sequestration sites as part of its carbon management business.[257] In Alabama, Tenaska is

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[250] Four of these final permit decisions expired after they were issued and are not reflected in EPA's Underground Injection Control (UIC) Class VI Permit Tracker. *See https://www.epa.gov/uic/current-class-vi-projects-under-review-epa* (noting that only active Class VI permits are included in the "Final Permit Decisions Issued" count).
[251] U.S. Environmental Protection Agency, "Underground Injection Control (UIC) Class VI Permit Tracker," January 3, 2025, *https://www.epa.gov/uic/current-class-vi-projects-under-review-epa.*
[252] *See id.*
[253] U.S. Environmental Protection Agency, "Primary Enforcement Authority for the Underground Injection Control Program," *https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0#:~:text=Louisiana%2C%20North%20Dakota%2C%20and%20Wyoming,states%2C%20territories%2C%20and%20trib@hoes.*
[254] U.S. Environmental Protection Agency, "Proposed Arizona Underground Injection Control Primacy Program," *https://www.epa.gov/uic/az-primacy.*
[255] Office of the Federal Register, "Environmental Protection Agency: West Virginia Underground Injection Control (UIC) Program; Class VI Primacy," November 27, 2024, *https://www.govinfo.gov/content/pkg/FR-2024-11-27/pdf/2024-27638.pdf*; U.S. Environmental Protection Agency, "Public Notice: Proposed Rule: West Virginia Underground Injection Control Program Class VI Primacy," November 27, 2024, *https://www.epa.gov/wv/proposed-rule-west-virginia-underground-injection-control-program-class-vi-primacy.*
[256] U.S. Environmental Protection Agency, "Primary Enforcement Authority for the Underground Injection Control Program," *https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0.*
[257] California Resources Corporation, "Carbon Terravault," *https://www.crc.com/carbon-terravault/vaults/default.aspx.*

developing the Longleaf CCS Hub in Mobile County, Alabama.[258] The project submitted a Class VI permit application in May 2023.[259] Tenaska is also developing CCS hub with components in Ohio,[260] West Virginia,[261] and Pennsylvania.[262] Multiple sequestration hubs are in development in Louisiana.[263] Talos Energy is also developing a CCS sequestration hub in Louisiana to store 500 million metric tonnes of CO_2.[264] In Michigan, Lambda Energy Resources is developing infrastructure to store 160 million metric tonnes of CO_2.[265] In New Mexico, the Four Corners Carbon Storage is being developed with partial funding from DOE.[266] In October 2024, ExxonMobil executed a lease with the Texas General Land Office for a more than 270,000 acre offshore CO_2 storage site off the Texas coast.[267] In December, Rayonier Inc and Reliant Carbon Capture and Storage announced a partnership granting Reliant access to approximately 140,000 acres of Rayonier land in Alabama. Reliant is currently finalizing an engineering design report for a power plant in that area.[268]

IV. Hydrogen In Combustion Turbines

In addition to the many new and existing NGCC units that are developing 90% or greater CCS, numerous new NGCC units are under development that can combust hydrogen, instead of natural

[258] Tenaska, "Tenaska's Longleaf CCS Hub to Support Carbon Reduction in South Alabama," March 22, 2024, *https://www.tenaska.com/tenaskas-longleaf-ccs-hub-to-support-carbon-reduction-in-south-alabama/.*
[259] Longleaf CCS Hub, "Longleaf CCS Hub," *https://longleafccs.com/.*
[260] Tri-State CCS Hub, "Tri-State CCS Buckeye," *https://tristateccs.com/ccs-buckeye/.*
[261] Tri-State CCS Hub, "Tri-State CCS Redbud," *https://tristateccs.com/ccs-redbud/.*
[262] Tri-State CCS Hub, "Tri-State CCS Oak Grove," *https://tristateccs.com/tri-state-ccs-oak-grove/.*
[263] Oil & Gas Watch, "Carbon Capture and Storage in Louisiana," *https://environmentalintegrity.org/wp-content/uploads/2024/01/OGW_LACCSProjects_FactSheet_Final.pdf.*
[264] Talos Energy, "Talos Energy Announces Lease Agreement for Major Carbon Sequestration Hub in Mississippi River Industrial Corridor," February 15, 2022, *https://www.talosenergy.com/investor-relations/news/news-details/2022/TALOS-ENERGY-ANNOUNCES-LEASE-AGREEMENT-FOR-MAJOR-CARBON-SEQUESTRATION-HUB-IN-MISSISSIPPI-RIVER-INDUSTRIAL-CORRIDOR/default.aspx.*
[265] Lambda Energy Resources, "Michigan's Premiere Carbon Storage Provider," *https://lambdaenergyllc.com/co2-sequestration.*
[266] U.S. DOE NETL, "Bipartisan Infrastructure Law (BIL): Four Corners Carbon Storage Hub: CarbonSAFE Phase III Project," August 2024, *https://netl.doe.gov/sites/default/files/netl-file/24CM/24CM_CTS1_9_Ampomah2.pdf.*
[267] Exxon Mobil, "Exxon Mobil secures largest CO2 offshore storage site in the U.S.," October 10, 2024, *https://corporate.exxonmobil.com/news/news-releases/2024/10102024_exxonmobil-secures-largest-carbon-offshore-storage-site-in-the-us.*
[268] Carbon Herald, "Rayonier And Reliant Partner For Carbon Capture And Storage in Alabama," December 27, 2024, *https://carbonherald.com/rayonier-and-reliant-partner-for-carbon-capture-and-storage-in-alabama/.*

gas. This development provides a useful option for many NGCC units to comply with the Carbon Pollution Standards requirements: By combusting hydrogen, they can meet the applicable CO_2 emissions standards, and thereby obviate the need to install CCS.

There are two key issues related to the feasibility of combusting hydrogen in a turbine. The first is whether the turbine itself is capable of combusting hydrogen, and the second is whether hydrogen is available at the turbine. MSEH explains that its turbine will be able to combust 30% to 50% hydrogen when it begins operations and that it will eventually be able to combust 100% hydrogen. It explains that with hydrogen as its fuel, its turbine "would be one of the first, if not the first, large scale hydrogen-fired dispatchable power plants with a significant output of carbon free power." It further claims that the project is "on the leading edge of gas and hydrogen powered baseload technology." Based on this description, the project is similar to many turbine projects under development today in that most of them are being built to eventually combust hydrogen in the near future. In fact, the most advanced hydrogen turbine projects are being designed and built to combust hydrogen as soon as they begin operations.

There are multiple examples across the country of projects being built to combust hydrogen. For instance, the Long Ridge Power Plant in Ohio, which commenced construction in 2019, announced in 2020 its intentions to move to hydrogen.[269] The Entergy, Orange County plant which commenced construction in 2023 and is scheduled to come on-line in 2026 is capable of burning 30% hydrogen when it begins operations.[270] Turbine manufacturers are now providing hydrogen co-firing as a standard feature on their turbines. For instance, GE explains that their 9HA turbines are capable of firing 50% hydrogen.[271]

While most turbine projects today are designed to be able to combust hydrogen, some are going a step further and are planning to combust hydrogen when they begin operations. For instance, the Intermountain Power Project in Utah is scheduled to come on-line in 2025 and plans to combust 30% hydrogen when it begins operations[272]. The plant is co-located with the ACES Delta Project. ACES is a clean energy production and storage facility that will be able to create and store hydrogen that can be used at the neighboring IPP facility as well as by other users.[273] Los Angeles Department of Water and Power (LAPWD) is also developing a hydrogen turbine project that is targeted to come on-line in 2030 and to combust hydrogen when it begins

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[269] Long Ridge Energy & Power, "Long Ridge Terminal Partners with New Fortress Energy and GE to Transition Power Plant to Zero-Carbon Hydrogen," October 13, 2020, *https://www.longridgeenergy.com/news/2020-10-13-long-ridge-energy-terminal-partners-with-new-fortress-energy-and-ge-to-transition-power-plant-to-zero-carbon-hydrogen.*
[270] Fuel Cell Works, "Entergy Texas Initiates Construction of Hydrogen-Ready Orange County Advanced Power Station," May 1, 2023, *https://fuelcellsworks.com/news/entergy-texas-initiates-construction-of-hydrogen-ready-orange-county-advanced-power-station.*
[271] GE Vernova, "9HA gas turbine," *https://www.gevernova.com/gas-power/products/gas-turbines/9ha.*
[272] Intermountain Power Agency, "IPP Renewed," *https://www.ipautah.com/ipp-renewed/#4.*
[273] ACES Delta, "Advanced clean Energy Storage Site," *https://aces-delta.com/sites/.*

operations.[274] Additionally, GE Vernova has announced that four new LM6000VELOX (200 MW total) gas turbines will operate on 100% renewable hydrogen at the Whyalla hydrogen power plant in the Upper Spencer Gulf, South Australia.[275] Commissioning of the project is expected in 2026.[276]

MSEH did not explain in its petition how it intends to eventually obtain the hydrogen for its project, EPA understands that there are at least three approaches that MSEH could take. First, MSEH could convert fossil fuels into hydrogen. In fact, there are at least three projects in West Virginia pursuing this approach. Omnis Energy is converting the Pleasants Power Plant in West Virginia to run on 100% hydrogen created from coal using a pyrolysis process. Omnis plans to have the plant running on 100% hydrogen by 2025.[277] The project utilizes the captured carbon for creation of graphite products, so no sequestration infrastructure is needed. With assistance from the State of West Virginia, Babcock and Wilcox is developing a hydrogen production/carbon capture facility to convert coal and biomass into hydrogen. The project will utilize B&W's Brightloop Chemical Looping Technology. While an ultimate user of the hydrogen has not been publicly identified, B&W notes that the hydrogen generated "could be used for a variety of purposes including power generation and industrial applications."[278] B&W has at least three other Brightloop projects under development: a small, three to five ton production facility in Massilon Ohio which is projected to be on-line by early 2026 and two medium sized 10 to 50 ton projects in Wyoming and Ohio.[279] B&W projects that they will be

[274] Los Angeles Times, "L.A. is shutting down its largest gas plant – and replacing it with an unproven hydrogen project," February 8, 2023, *https://www.latimes.com/business/story/2023-02-08/l-a-is-shutting-down-a-coastal-gas-plant-and-replacing-it-with-hydrogen.*

[275] Power Engineering, "GE Vernova launches its first 100% hydrogen-fuelled aeroderivative gas turbine," November 26, 2024, *https://www.power-eng.com/gas-turbines/ge-vernova-launches-its-first-100-hydrogen-fuelled-aeroderivative-gas-turbine/.*

[276] GE Vernova, "GE Vernova announces its first 100 percent hydrogen-fueled aeroderivative gas turbine solution," November 20, 2024, *https://www.gevernova.com/news/press-releases/ge-vernova-announces-first-100-percent-hydrogen-aeroderivative-gas-whyalla.*

[277] The St. Marys Oracle, "Omnis Energy Marks Early Success with Clean Electricity Demonstration that Records Several World Firsts," August 14, 2024, *https://mcusercontent.com/8f96201ded16a52b945a67e45/files/d20fe0e7-63bc-e8e6-a069-cd8d30ebb37e/Omnis_Demonstration_Local_Coverage_B.pdf.*

[278] Babcock & Wilcox, "State of West Virginia Agrees to Provide $10 Million for Development of Babcock & Wilcox BrightLoop Hydrogen and Carbon Capture Project," December 10, 2024, *https://www.babcock.com/home/about/corporate/news/state-of-west-virginia-agrees-to-provide-10-million-for-development-of-babcock-and-wilcox-brightloop-hydrogen-and-carbon-capture-project.*

[279] Canton Repository, "'A big win.' Babcock & Wilson investing $60 million in Massillon hydrogen production site," September 10, 2024, *https://www.cantonrep.com/story/business/2024/09/09/babcock-wilcox-invests-in-massillon-hydrogen-production-plant/75085160007/.*

able to develop projects in the 100 to 250 ton range by 2029.[280] Fidelis New Energy is developing a 640 ton per day hydrogen production facility with CCS in Mason County West Virginia.[281] While EPA has not evaluated whether any of these technologies would meet any applicable requirements, such as qualifying as Best Available Control Technology under the Clean Air Act Prevention of Significant Deterioration requirements, EPA notes that all three of them are on development schedules consistent with being able to be used at the MSEH's Mountain State Clean Energy project. They would all be consistent with MSEH's stated long-term goal of moving the project to 100% hydrogen and would allow for the unit to operate in full compliance with the Carbon Pollution Standards requirements for new combustion turbines.

A second approach to producing hydrogen would be to use electrolysis (electricity and water) to generate hydrogen. This is the approach being taken at the IPP/ACEs project described above. It is also the approach being taken at the Duke Energy Debray retrofit project where Duke is working to power a 74 MW peaking turbine 100% with hydrogen generated through electrolysis.[282] In both of these projects, developers are planning to power the electrolyzers using 100% renewable energy.

A third approach would be to use naturally occurring hydrogen. Unlike the two approaches outlined above, EPA is not aware of any projects under development intending to use naturally occurring hydrogen to power a turbine. EPA is also not aware of any exploration for naturally occurring hydrogen in West Virginia, but there are efforts to produce naturally occurring hydrogen in multiple states including Kansas and Nebraska[283] as well as Texas.[284]

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[280] Babcock & Wilcox, "BrightLoop Low-Carbon Hydrogen Technology," *https://www.babcock.com/home/environmental/decarbonization/low-carbon-hydrogen/.*
[281] Fidelis New Energy, "Project: Mountaineer GigaSystem," *https://fidelisinfra.com/project/mountaineer-gigasystem/.*
[282] Power Magazine, "Pioneering Hydrogen-Powered Gas Peaking: Inside Duke Energy's DeBary Project," November 16, 2023, *https://www.powermag.com/pioneering-hydrogen-powered-gas-peaking-inside-duke-energys-debary-project/.*
[283] Insurance Journal, "Hydrogen Wildcatters Are Betting Big on Kansas to Strike it Rich," November 19, 2024, *https://www.insurancejournal.com/news/midwest/2024/11/19/801804.htm.*
[284] Max Power, "Max Power and Larin Engineering Launch USA Natural Hydrogen Search in Texas," July 10, 2024, *https://www.maxpowermining.com/max-power-and-larin-engineering-launch-usa-natural-hydrogen-search-in-texas/.*

Appendix B: New Electric Generation Memorandum

Petitioner Mountain State Energy Holdings, LLC (MSEH) argued that surging electricity demand casts doubt on EPA's resource adequacy analysis. As noted in the reconsideration denial, EPA rejects these concerns on a technical basis. EPA's projections and reliability-related assumptions are reasonable and appropriate, and should be viewed in the context of the agency's history of reasonably projecting the impacts of its rules on the electricity sector. In addition, as also noted in the reconsideration denial, the Final Rules include several compliance flexibilities that further support its resource adequacy analysis, and that MSEH's petition does not account for. The Final Rules are robust to future uncertainty and, contrary to Petitioner's arguments, are not limited to any single future scenario.

This document highlights another area that supports EPA's resource adequacy analysis: the development of zero emitting and zero emitting enabling technologies is likely to proceed faster than projected in EPA's IPM analysis. Historically, power sector modeling, including IPM, has conservatively projected the pace of technology change. Examples include projecting shifts to natural gas as advanced drilling technologies greatly increased the supply of natural gas, growth of solar energy, and growth of storage. In addition, at the present time, the energy sector is developing very quickly, with new demand developing due in part to the rapid development of artificial intelligence and new zero-emitting generation developing rapidly due in large part to the recently enacted and expanded clean energy tax incentives in the Inflation Reduction Act (IRA), coupled with the preferences of many companies, states and consumers for clean energy. EPA's Final Rules modeling made reasonable projections based on information then available, but these ongoing rapid developments highlight the possibility that both electricity demand and zero-emitting electricity generation (supply) may materialize faster. If demand is higher than EPA assumed, it is unlikely that such demand will lead to an equal amount of growth in fossil-fuel use. This is in large part because of this rapid growth in clean energy. The demand growth is, broadly speaking, balanced by the growth in clean energy, and thus does not undermine the EPA's resource adequacy analysis.

This document compiles recent evidence indicating that zero emitting generation growth is likely to be higher than EPA projected in the Final Rules. MSEH's petition is flawed because it fails to recognize this growth in zero emitting generation in its evaluation of post-signature trends. Omitting the supply-side of the ledger in an updated supply/demand balance exercise inherent to resource adequacy assessment overstates the impact of load growth.

New zero-emitting generation technologies that have the potential to exceed the projections in IPM include baseload/dispatchable technologies, including nuclear and geothermal energy; as well as solar (both utility scale and distributed) and wind (both onshore and offshore) energy;

and technologies that help address the intermittency issues associated with solar and wind energy, including short and long term storage and virtual power plants. Further, electric users, utilities, FERC, and regional transmission organizations all have the ability to facilitate increased generation and are all working on mechanisms to do so.

This document compares EPA's IPM projections for zero emitting technologies to current trends and shows that for many of the key zero emitting technologies, new generation is by-and-large developing faster, and in some cases much faster, than projected in EPA's modeling analysis.[285] While recent trends indicate that wind (on and off shore) technology appears to be developing more slowly than IPM projections, for all other zero-emitting generating technologies, including geothermal, nuclear and solar, there is significant evidence that the new generation capacity may develop more quickly than EPA's IPM projections in the final rule. Further, technologies such as energy storage and virtual power plants which allow for more intermittent generating resources like wind and solar and which provide additional reliability safeguards also appear to be growing faster than EPA's IPM projections from the Final Rules suggested.

The information below should not be taken as a definitive projection of the future, but rather as indications that the possibility that future demand will be greater than EPA projected will, broadly speaking, be balanced by the possibility that zero emitting generation will be greater as well.

Table 1. Summary

Technology	**EPA IPM Projections "All Rules" run[286]**	**State of technology today and scale of short-term development**
Geothermal	There are no projected increases in geothermal capacity in this run.	Multiple companies in multiple states are developing advanced geothermal projects. At least one 400 MW plant (with a potential to expand to 2000 MW) is on track to come on-line by 2028.
Nuclear	EPA projected a decrease in capacity from 96 GW to 84 GW between 2023 and 2035	Multiple companies in multiple states are working on plans to expand nuclear power including: restarting retired plants, extending the lives of existing plants, uprating existing plants and building new plants. There is also significant build out of infrastructure to support new nuclear

[285] Low emitting gas technologies (primarily NGCC with CCS are addressed in Appendix A: CCS Projects Memorandum).
[286] U.S. EPA, "Technical Memo - IPM Sensitivity Runs," April 2024, Docket ID No. EPA-HQ-OAR-2023-0072-8917.

		development including construction of fuel processing facilities and small modular and micro reactor fabrication facilities
Utility Scale Solar	EPA projected an increase in capacity from 91 GW in 2023 to 184 GW in 2028 and 304 GW in 2035. That is an increase of 17.75 GW per year	In August 2024, EIA reported that the U.S. was on track to install 37 GW of solar in 2024, more than double the average GW of utility scale solar projected by IPM.[287]
Distributed solar	EPA projected an increase of 48 GW in 2023 to 81 GW in 2028 and 121 GW in 2035. That is an increase of 6.1 GW per year.	Projections for distributed solar in 2024 are about 8 GW, more than the 6.1 GW per year projected by IPM[288].
Onshore Wind	EPA projected onshore wind to grow from 147 GW to 392 GW in 2035, a growth rate of just over 20 GW a year.	About 7 GW of onshore wind were installed in 2024, but there are indications it may increase in the coming years. As explained below, it is still likely to fall short of EPA's IPM projections.
Offshore Wind	EPA projected 12 GW of offshore wind capacity by 2028 and 36 GW of capacity by 2035.	The Bureau of Offshore Energy Management has approved 10 projects representing over 15 GW of offshore wind capacity.[289]
Short Term Energy Storage (4 hour batteries or less)	EPA projected short term energy storage to grow from 15 GW in 2023 to 113 GW in 2035, a growth rate of about 8.2 GW per year.	In 2024, EIA projects that 15 GW of energy storage will be built. EIA does not break out whether that is short or long term storage, but the vast

[287] U.S. Energy Information Administration, "U.S. power grid added 20.2 GW of generating capacity in the first half of 2024," August 19, 2024, *https://www.eia.gov/todayinenergy/detail.php?id=62864.*
[288] PV Magazine, "U.S. targets 50 gigawatts of solar in 2024," December 5, 2024, *https://pv-magazine-usa.com/2024/12/05/u-s-targets-50-gigawatts-of-solar-in-2024*.
[289] Bureau of Ocean Energy Management, "BOEM Identifies Environmental Measures for Wind Energy Development in the New York Bight," December 2, 2024, *https://www.boem.gov/newsroom/press-releases/boem-identifies-environmental-measures-wind-energy-development-new-york.*

		majority of storage currently being built is short term.[290]
Long Term Energy Storage (8 hour batteries)	EPA projected that long term energy storage will increase from 0 GW in 2023 to 7 GW in 2028 and 10 GW in 2035, which would require a build out of approximately 1 GW per year.	Multiple long term energy storage projects are under development in the U.S. This includes opening at least two long term battery factories as well as multiple non-battery projects. Many of these projects are designed to provide more than 8 hours of storage.
Virtual Power Plants	EPA did not model virtual power plants	Multiple virtual power plants are operating with others in development. DOE suggests that current deployment of virtual power plants of 30 GW to 60 GW could grow to 80 GW to 160 GW by 2030.[291]

I. Geothermal

EPA's modeling does not assume any growth in geothermal. However, we are currently seeing indications of significant growth. DOE's "Pathway's to Commercial Liftoff: Next Generation Geothermal,"[292] identifies significant opportunities for geothermal using new technologies.

Multiple companies are currently developing advanced geothermal projects in the United States using a variety of technological approaches:

Fervo is pursuing the largest current U.S. project. Fervo's Cape Station in Utah is targeting 90 MWs by 2026 in phase one, and at least 400 MWs by 2028 in Phase II. In October, 2024, the

[290] Environmental Science Associates (ESA), "Charged Up: Battery Storage Demand Continues," December 12, 2024, *https://esassoc.com/news-and-ideas/2024/12/charged-up-battery-storage-demand-continues/*.
[291] U.S. Department of Energy, "Pathways to Commercial Liftoff: The pathway to Virtual Power Plants Commercial Liftoff," *https://liftoff.energy.gov/vpp/*.
[292] U.S. Department of Energy, "Pathways to Commercial Liftoff: Next-Generation Geothermal Power," March 2024, *https://liftoff.energy.gov/wp-content/uploads/2024/03/LIFTOFF_DOE_NextGen_Geothermal_v14.pdf*.

Department of Interior approved an expansion of the project to up to 2000 MWs[293]. Fervo has already contracted for nearly 400 MWs of generation from the project[294].

Sage Geosystems is pursuing multiple U.S. projects both for baseload power and for intermittent power. Sage is developing a baseload project of up to 150 MWs at an undisclosed location for Meta. Importantly, this will be the first U.S. utility scale geothermal project for electricity production east of the Rockies.[295] Sage is aiming for a 2027 operational date for the first phase of the project. Sage is also building a 3 MW short/long term energy storage facility in Texas.

Eavor is developing a project for the Department of Defense at the joint base San Antonio facility in Texas. Eavor has also demonstrated the ability to successfully drill to over 3 miles at a site in New Mexico, greatly expanding the potential geographic reach of their technology.

Quaise Energy is working with Nevada Gold Mines (NGM) to provide steam to NGM's existing fossil-fuel-fired power plant. If successful, this would be the first retrofit of an existing fossil-steam plant to use geothermal as an alternative heat source.[296]

In its March 2024, "Pathways to Commercial Liftoff: Next Generation Geothermal Report", DOE suggested that commercial liftoff would require 2 GW to 5 GW of geothermal in 5 to 10 different geologic settings by 2030, which could put the industry on a path to unleashing from 88 GW to 125 GW of new geothermal generation between 2030 and 2050. DOE further noted that, "recent technical successes indicate the industry is on track to achieving ambitious targets" and that "well development costs decreased from $13 million to under $5 million in the first two large scale commercial [enhanced geothermal system] pilots in the U.S." With full scale projects in various stages of development from exploration to construction in California, Colorado, Nevada, Utah, Texas, and a site east of the Rockies, the industry is well on its way to meeting the DOE goal of 2 GW to 5 GW across 4 to 6 states by 2030.

Table 2. Examples of States Investing in Advanced Geothermal Projects

State	**Project**
California	Multiple technology companies are developing pilot projects at California's Geysers Geothermal Field. Three projects by Eavor

[293] Utility Dive, "Interior approves 2-GW Fervo Energy geothermal project in Utah," October 21, 2024, *https://www.utilitydive.com/news/interior-geothermal-fervo-energy-categorical-exclusion-nepa/730413/*.
[294] Fervo Energy, "Fervo Energy Announces 320 MW Power Purchase Agreements with Southern California Edison," June 25, 2024, *https://fervoenergy.com/fervo-energy-announces-320-mw-power-purchase-agreements-with-southern-california-edison/*.
[295] Sage Geosystems, "Press Release. Sage Geosystems and Meta Announce Agreement for Next-Generation Geothermal Power Generation," *https://www.sagegeosystems.com/sage-geosystems-and-meta-announce-agreement-for-next-generation-geothermal-power-generation/*.
[296] Quaise Energy, "Quaise Energy and Nevada Gold Mines Partner on Deep Geothermal Pilot Plant to Decarbonize Mining," December 3, 2024, *https://www.quaise.energy/news/quaise-energy-and-nevada-gold-mines-partner-on-deep-geothermal-pilot-plant-to-decarbonize-mining*.

	Technologies, Chevron New Energies and Cyrq Energy could ultimately scale to three 200 MW commercial projects.[297]
Colorado	The State has awarded several grants to allow for test drilling for geothermal electricity projects. The first project is for Geothermal Technologies Inc. and could ultimately result in a 180 MW to 200 MW plant.[298] The second project is the Florida Mesa Geothermal Project that could ultimately result in a 50 MW commercial project and the final project is for Mt. Princeton Geothermal LLC and could ultimately result in a 10 MW plant.
Nevada	Quaise Energy is working with NGM to repower an existing fossil plant to use geothermal.
Utah	Fervo is pursuing an up to 2000 MW project in Utah.
Texas	Eavor is pursuing a project with DOD in Texas and Sage is developing a storage project.

II. Nuclear

EPA's modeling also does not assume any increase in nuclear capacity, and in fact it assumes that nuclear capacity decreases from 96 GW to 84 GW between 2023 and 2035. There has been significant development in nuclear since EPA's modeling for the Final Rules. In DOE's, "Pathway's to Commercial Liftoff – Advanced Nuclear," DOE explains that, "[i]n 2022, utilities were shutting down nuclear reactors. In 2024, they are extending reactor lives to 80 years, planning to uprate capacity and restarting formerly closed reactors." DOE further notes that US nuclear capacity has the potential to triple by 2050.

There are four paths to increasing nuclear generation: restarting existing generation, extending the lives of existing generation, uprating (or increasing the capacity) of existing generation, and building new generation. There is significant evidence that all of these actions are happening.

A. Existing Fleet Improvements

There are currently efforts underway to restart two existing nuclear power plants, the 800 MW Palisades Plant in Michigan and the 800 MM Three Mile Island Plant in Pennsylvania.

The Palisades plant already has significant financing in place, including federal loans, power purchase agreements and financial support from the state of Michigan. Holtec, the project

[297] Enviro Updates, "3 new-tech geothermal plans to be considered for boosting power at The Geysers," *https://envirocentersoco.org/updates/2023/02/3-new-tech-geothermal-plans-to-be-considered-for-boosting-power-at-the-geysers/.*

[298] Colorado Energy Office, "Geothermal Energy Grant Program, Round 1 Awardees," *https://drive.google.com/file/d/1E9W_GQhtgWaKxO1CyCEf7Vr42tslxYrz/view.*

developer is also working with NRC on approval to restart the plant and is targeting restarting the plant by the end of 2025.[299] NextEra is also considering re-opening the 615 MW Duane Arnold Nuclear Power Plant in Iowa.[300]

Constellation and Microsoft recently announced a deal to restart the 800 MW Three Mile Island Unit 1. The companies are targeting 2028 for re-opening.[301] Next Era, the owner/operator of the 615 MWe Duane Arnold Plant in Iowa, has also indicated that it is considering whether it would make economic sense to restart that plant.[302]

Historically, NRC has approved over 8000 MWs of uprates to existing nuclear facilities.[303] While there are currently no uprate requests before NRC[304], DOE has projected that there is a near term potential of 2 to 8 additional GWs from nuclear uprates.[305] Entergy has announced that it is considering uprates at several of its units.[306]

A number of reactors have licenses that expire before 2035. Various modeling has different assumptions regarding retirement of these units, for instance, the most recent IPM modeling assumes that 10 GW of nuclear generation retires by 2035. As electric demand increases and there is growing interest in re-starting retired reactors, it is likely that some of these plants will instead decide to seek license extensions.

B. Small Modular Reactors

There are multiple companies developing small modular nuclear technology. There are also a number of states and/or companies that are investing in deploying SMRs.

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[299] Utility Dive, "Palisades nuclear plant restart on track for October 2025 despite NRC petition: Holtec International," September 23, 2024, *https://www.utilitydive.com/news/palisades-nuclear-plant-restart-on-track-for-october-2025-despite-nrc-petit/727780/*.
[300] Nuclear Newswire, "NextEra Energy considering Duane Arnold plant restart," July 26, 2024, *https://www.ans.org/news/article-6248/nextera-energy-considering-duane-arnold-plant-restart/*.
[301] MIT Technology Review, "Why Microsoft made a deal to help restart Three Mile Island," September 26, 2024, *https://www.technologyreview.com/2024/09/26/1104516/three-mile-island-microsoft/*.
[302] World Nuclear News, "NextEra eyes restart opportunity for shuttered Iowa plant," July 26, 2024, *https://www.world-nuclear-news.org/Articles/NextEra-eyes-restart-opportunity-for-shuttered-Iow*.
[303] U.S. Nuclear Regulatory Commission, "Backgrounder on Power Uprates for Nuclear Plants," January 2022, *https://www.nrc.gov/reading-rm/doc-collections/fact-sheets/power-uprates.html*.
[304] U.S. Nuclear Regulatory Commission, "Expected Applications for Power Uprates," February 8, 2024, *https://www.nrc.gov/reactors/operating/licensing/power-uprates/status-power-apps/expected-applications.html*
[305] U.S. Department of Energy, "Pathways to Commercial Liftoff: Advanced Nuclear," September 2024, *https://liftoff.energy.gov/advanced-nuclear/*.
[306] MSN, "Entergy surges to new highs as execs discuss increasing nuclear power capacity," *https://www.msn.com/en-us/money/markets/entergy-surges-to-new-highs-as-execs-discuss-increasing-nuclear-power-capacity/ar-AA1thZ4k*.

Terrapower and PacifiCorp have begun construction of a 345 MW reactor in Kemmerer Wyoming. The project broke ground in June, 2024.[307] Terrapower has submitted a licensing application to NRC and is targeting 2030 for plant startup[308]. This project is part of DOE's Advanced Reactor Demonstration Program.[309]

X-Energy is also part of the DOE Advanced Reactor Program and is developing a 4 unit 320 MW facility in Texas with Dow.[310] They are targeting a commence construction date in 2026 and project completion by the end of 2030.[311] X-Energy is also working with Northwest Energy on a potential project at Hannford Reservation in Washington. They are considering applying for a license for up to 12 units, but would intend to start the project with a 4 unit, 320 MW plant.[312] Amazon has now signed onto the Northwest project and in addition to committing to purchase electricity from the first 4 SMRs, is contributing to early development work.[313]

GE-Hitachi is also developing a 300 MW SMR. Its first unit is under construction in Ontario and Ontario Hydro has announced its intention to build 3 more units on the same site. Work is underway to obtain a Canadian license for the facility.[314]

Holtec, which is leading the restart of the Palisades Plant in Michigan, is also pursuing at least one SMR project. It has announced plans for two 300 MW SMRs at the Palisades Plant. It intends to submit an application for the project by the end of 2026 and is hoping to bring the units on-line by 2030.[315] While Holtec has not yet submitted an application to NRC, it is working through the approval process in the UK.[316]

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[307] TerraPower, "TerraPower Begins Construction on Advanced Nuclear Project in Wyoming," June 10, 2024, *https://www.terrapower.com/terrapower-begins-construction-in-wyoming.*
[308] The Gates Notes, "We just broke ground on America's next-gen nuclear facility," June 10, 2024, *https://www.gatesnotes.com/Wyoming-TerraPower-groundbreaking.*
[309] U.S. Department of Energy, "Advanced Reactor Demonstration Projects," *https://www.energy.gov/oced/advanced-reactor-demonstration-projects-0.*
[310] *Id*.
[311] X Energy, "Advanced Nuclear Reactor Project in Seadrift, Texas," *https://x-energy.com/seadrift.*
[312] U.S. Nuclear Regulatory Commission, "Small Modular Reactor: Project Kickoff," *https://www.nrc.gov/docs/ML2421/ML24218A141.pdf.*
[313] X Energy, "Amazon Invests in X-energy to Support Advanced Small Modular Nuclear Reactors and Expand Carbon-Free Power," October 16, 2024, *https://x-energy.com/media/news-releases/amazon-invests-in-x-energy-to-support-advanced-small-modular-nuclear-reactors-and-expand-carbon-free-power.*
[314] Ontario Power Generation Inc., "Story of Darlington New Nuclear Project," *https://www.opg.com/projects-services/projects/nuclear/smr/darlington-smr/.*
[315] Utility Dive, "Palisades nuclear plant restart on track for October 2025 despite NRC petition: Holtec International," September 23, 2024, *https://www.utilitydive.com/news/palisades-nuclear-plant-restart-on-track-for-october-2025-despite-nrc-petit/727780/.*
[316] Holtec International, "Holtec's UK Subsidiary Obtains Crucial First-Step Regulatory Approval for its SMR-300 Pressurized Water Reactor in Record Time," August 1, 2024, *https://holtecinternational.com/2024/08/01/hh-39-13/.*

Oklo is developing a scalable reactor technology that can be sized from 15 MW to 50 MW. Its first project, currently under development, is a 15 MW reactor at the Idaho National Lab. Oklo is working on a project for its second and third reactors with the Southern Ohio Diversification Initiative. Those three reactors are all planned to be 15 MWe. Oklo has announced non-binding letters of intent for over 1300 MWs of generation, including letters of intent with Equinix, Diamond Back and others.[317]

Kairos has signed an agreement to provide 500 MW worth of SMRs to Google. The first reactor is scheduled to be delivered by 2030 and the last by 2035. Kairos's reactor is a 75 MW molten salt reactor (intended to be sold in pairs). Kairos has a license for its first demonstration project at Oak Ridge Tennessee.

Nuscale has the only currently licensed SMR in the U.S. Nuscale is working with Standard Power on the potential for 2 GW of SMR capacity to support data centers in Ohio and Pennsylvania.

There are multiple other states/companies pursuing SMRs. For instance, TVA's Clinch River site has the only early site permit for an SMR, the TVA Board has approved $350 million for development of a reactor at that site and TVA is working with both GE-Hitachi and Kairos.[318] Dominion is pursuing one or more SMRs at its North Anna site.[319] Dominion and Amazon have also announced plans to look at SMRs together to power data centers in Virginia.[320] Duke's most recent IRP includes plans for 600 MW of SMR by 2035.[321]

The projects under development from the 7 SMR developers above represent over 4 GW in the 2030-35 time frame. Four of the developers cited above, Terrapower, X-Energy, Holtec and Kairos are receiving federal support as part of the Advanced Reactor Demonstration Program[322] and DOE has announced an additional $900 million for funding of additional SMR projects.

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[317] Tennessee Valley Authority Press Release, "TVA Board Approves Additional $150 Million in Advanced Nuclear Funding," August 22, 2024, *https://www.tva.com/newsroom/press-releases/tva-board-approves-additional--150-million-in-advanced-nuclear-funding.*
[318] World Nuclear News, "TVA approves further funding for Clinch River SMR," August 23, 2024, *https://www.world-nuclear-news.org/articles/tva-approves-further-funding-for-clinch-river-smr.*
[319] Virginia Public Media, "Dominion plans to operate small modular nuclear reactor," July 10, 2024, *https://www.vpm.org/news/2024-07-10/dominion-plans-to-operate-first-small-modular-nuclear-reactor-in-u-s.*
[320] Energy Central, "Amazon announces deal with Dominion Energy to develop a small nuclear reactor," October 21, 2024, *https://energycentral.com/news/amazon-announces-deal-dominion-energy-develop-small-nuclear-reactor-0.*
[321] Duke Energy, "Chapter NC Supplement: 2023-2024 Carbon Plan and Integrated Resource Plan Supplemental Planning Analysis," *https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/supplements/chapter-supplement-north-carolina.pdf?rev=65bb213404354b47b0492527ff2d0fb8.*
[322] U.S. Department of Energy, "Infographic: Advanced Reactor Development," December 15, 2020, *https://www.energy.gov/ne/articles/infographic-advanced-reactor-development.*

C. Micro-Reactors

Aala Atomics is working to test a microreactor at Idaho National Labs. It is aiming to have the test plant operating by 2027.[323] The company is also developing a manufacturing facility in Texas to build the test reactor and also to build the commercial reactors.[324]

D. New Conventional Reactors

Even though it was significantly over budget and took significantly longer to build than anticipated, the completion of Georgia Power's Vogtle Plant and increasing electric demand have revived interest in conventional nuclear reactors. The Nuclear Company is taking a fleet scale approach to nuclear power to mitigate risk. Its focus is bringing together multiple stakeholders to finance a multi-reactor program to "design once, build many". It is focused on an initial fleet of 6 GW of reactors at sites that already have some level of licensing and is targeting the mid 2030s to begin providing electricity. To date it has not announced any specific projects or utility partners.[325]

Table 3. Examples of States Investing in New Nuclear Projects (including both nuclear support projects and nuclear projects that could contribute to new generation by 2035)[326]

State	Project
Alabama	The Ultrasafe Nuclear Corporation is developing a factory to produce its microreactors.
Arkansas	Entergy is considering uprates to an existing nuclear plant.
Connecticut	Dominion Power is considering a license extension for both units at its Millstone plant, which would extend the lifetime for one unit from 2035 to 2055 and for the second unit from 2045 to 2065.
Idaho	Aala Atomics is partnering with Idaho Falls Power to build a 75 MW, 7 unit micro-reactor facility. The project could come on-line as early as 2030.
Indiana	Purdue is doing a study for Indiana's Office of Energy Development.

[323] Aalo Atomics, "Aalo Atomics Granted Permission to Pursue DOE Authorization for Experimental Reactor at INL," December 3, 2024, *https://www.aalo.com/post/aalo-atomics-granted-permission-to-pursue-doe-authorization-for-experimental-reactor-at-inl.*
[324] Aalo Atomics, "Aalo Opens 40k Sqft Factory HQ in Austin, Texas," August 21, 2024, *https://www.aalo.com/post/announcing-our-new-factory-hq-in-austin-texas.*
[325] Utility Dive, "The Nuclear Co. exists stealth, plans to deploy standardized 6-GW nuclear fleet," July 22, 2024, *https://www.utilitydive.com/news/the-nuclear-company-exits-stealth-to-deploy-standardized-6-gw-nuclear-fleet/721983/.*
[326] Multiple additional states including Florida and Kentucky are considering nuclear but currently focusing on post 2035.

Iowa	NextEra is considering restarting the Duan Arnold Nuclear Plant.[327]
Kentucky	Global Laser Enrichment is pursuing the siting of a uranium enrichment facility in Kentucky.[328]
Michigan	Michigan is considering both a restart of the Palisades Nuclear Plant and construction of SMRs at the same facility.
Minnesota	Xcel has announced plans to extend the life of its nuclear units in Minnesota into the 2050s.
New York	Nano Nuclear and Digihost have signed an MOU to investigate integrating Nano Nuclear's micro-reactors into Digihost's existing operations. They are targeting the early 2030s.[329]
North Carolina	Duke Power has announced intentions to build two SMRs in North Carolina in the 2030s and has indicated that it intends to announce the specific technology vendor in 2025.[330]
Ohio	Oklo has plans to install its second and third reactors in Ohio.
Pennsylvania	Constellation is working to re-open the Three Mile Island Nuclear Power Plant.
South Carolina	South Carolina is exploring the possibility of re-starting construction of VC Summer Units 2 and 3[331].
Tennessee	TVA is exploring building a 300 MW SMR at the Clinch River site in Tennessee.[332]

[327] Power Engineering, "NextEra Energy considering restart of Iowa nuclear plant," October 24, 2024, *https://www.power-eng.com/nuclear/nextera-energy-considering-restart-of-iowa-nuclear-plant/.*
[328] *Id.*
[329] Power Engineering, "New York combined cycle plant eyed for microreactor development for data centers," December 18, 2024, *https://www.power-eng.com/nuclear/new-projects-nuclear/new-york-combined-cycle-plant-eyed-for-microreactor-development-for-data-centers/.*
[330] The Carolina Journal, "Small modular nuclear reactors could be NC's affordable path to a carbon-free future," August 15, 2024, *https://www.carolinajournal.com/opinion/small-modular-nuclear-reactors-could-be-ncs-affordable-path-to-a-carbon-free-future/.*
[331] South Carolina Public Radio, "SC lawmakers want to tackle energy needs in 2025. Will that include VC Summer," November 12, 2024, *https://www.southcarolinapublicradio.org/sc-news/2024-11-12/sc-lawmakers-want-to-tackle-energy-needs-in-2025-will-that-include-vc-summer.*
[332] Tennessee Valley Authority, "TVA Board Approves Additional $150 Million in Advanced Nuclear Funding," August 22, 2024, *https://www.tva.com/newsroom/press-releases/tva-board-approves-additional--150-million-in-advanced-nuclear-funding.*

Texas	Dow is working with X-Energy to install an SMR at its Seadrift Manufacturing Facility. Texas A&M has announced plans to provide land for a test bed for next generation nuclear plants and the State has prepared a report concerning additional opportunities for nuclear in the state.[333]
Virginia	Dominion Energy has solicited proposals to add SMRs to its North Anna Nuclear facility.[334]
Washington	Energy Northwest, Amazon and X-Energy are working to develop an SMR project in Richland Washington. The first phase of the project would involve 320 MWs of capacity but the project could be expanded to include an additional 640 MWs of capacity.
Wisconsin	Dairyland Power has signed an MOU with Nuscale to look at installing SMRs to meet growing load.[335]
Wyoming	Terrapower is currently constructing an SMR in Kemerer Wyoming. Construction of non-nuclear components of the project has begun. A construction license has been submitted to the nuclear regulatory commission and construction of nuclear components will begin after that has been approved.[336]

III. Solar

IPM models two types of solar projects: large utility scale projects and smaller community projects. EIA reported that in 2024, about 37 GW of utility scale solar (the most ever in a single year in the U.S.) were scheduled to come on-line. About 8 GW of community scale solar was also scheduled to come on-line in 2024. In both cases, these numbers exceed the average annual builds of solar projected in IPM between 2023 and 2035. There are many indications that the growth of solar is likely to continue. There are nearly 1100 GW of solar projects currently in

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333 Power Engineering, "Is Texas ready for advanced nuclear? Governor Abbott thinks so," November 11, 2024, *https://www.power-eng.com/nuclear/is-texas-ready-for-advanced-nuclear-governor-abbott-thinks-so/.*

334 Virginia Public Media, "Dominion plans to operate small modular nuclear reactor," July 10, 2024, *https://www.vpm.org/news/2024-07-10/dominion-plans-to-operate-first-small-modular-nuclear-reactor-in-u-s.*

335 World Nuclear News, "Dairyland considers deployment of NuScale SMR," February 24, 2022, *https://www.world-nuclear-news.org/Articles/Dairyland-considers-deployment-of-NuScale-SMR.*

336 TerraPower, "TerraPower Begins Construction on Advanced Nuclear Project in Wyoming," June 10, 2024, *https://www.terrapower.com/terrapower-begins-construction-in-wyoming.*

interconnection queues[337]. While only a small portion of that is likely to be built (14% of the projects in the queue between 2000 and 2018 had been built by the end of 2023)[338], that still suggests significant additional buildout of solar is likely. Further, U.S. capacity to produce solar has also increased substantially. Between 2nd quarter 2022 (passage of the Inflation Reduction Act) and third quarter 2024, U.S. solar production capacity increased from 7 GW/year to nearly 40 GW/year[339].

IV. Wind

A. Onshore Wind

EPA projected about 20 GW of wind generation to be built per year between 2023 and 2035, but only about 7 GW were built in 2024. While there are reasons to believe that growth in on-shore wind may grow in the next several years, current data does not suggest a buildout as large as 20 GW per year. Wood Mackenzie forecasts 11 GW of new generation in 2025 and 14 per year between 2026 and 2030.[340] Continued build out of U.S. on-shore wind is consistent with investments in new on-shore wind turbine production facilities. GE Vernova and Siemens Gamesa have built onshore wind manufacturing facilities in New York and Iowa and Arcosa and CS Wind are building plants in New Mexico and Colorado.[341]

B. Offshore Wind

The Bureau of Offshore Energy Management has approved 10 projects representing over 15 GW of offshore wind capacity.[342] Some of those projects have stopped work due to economic concerns. Projects actively under development include the following.

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337 Lawrence Berkeley National Laboratory: Energy Markets & Policy, "Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection," *https://emp.lbl.gov/queues*.
338 *Id*.
339 Solar Energy Industries Association, "Solar Market Insight Report," December 4, 2024, *https://seia.org/research-resources/us-solar-market-insight/*.
340 Reuters, "US wind rebounds to set up stronger mid-term outlook," April 4, 2024, *https://www.reuters.com/business/energy/us-wind-rebounds-set-up-stronger-mid-term-outlook-2024-04-04/*.
341 *Id*.
342 Bureau of Ocean Energy Management, "BOEM Identifies Environmental Measures for Wind Energy Development in the New York Bight," December 2, 2024, *https://www.boem.gov/newsroom/press-releases/boem-identifies-environmental-measures-wind-energy-development-new-york*.

Vineyard Wind is the first utility scale project to commence operation in the U.S. The 800 MW facility is located in Massachusetts[343]. The facility was scheduled to come on-line in late 2024 but progress has been delayed due to failure of one of the turbine blades at the facility.[344]

Equinor has announced the closing of $3 billion in financing for the 810 MW Empire Wind Project in New York. The project is scheduled to come on-line in 2027.[345]

V. Short Term Storage

As noted above, the EPA projected approximately 8.2 GW of new short term (4 hour battery or less) storage plants to be built every year between 2023 and 2035. Based on announced projects, another 15 GW of short-term energy storage will be built in 2024 with another 9 GW in the queue for 2025[346]. Manufacturing for utility scale energy storage also continues to grow, another sign that significant growth in the short term storage segment is poised to continue. For instance, E-Storage announced that they would be building a new production facility in Shellbyville, Kentucky that is scheduled to be on-line by the end of 2025.[347]

VI. Long Term Storage

Multiple technologies can support long-term -- 8 hour or longer -- storage, including batteries, compressed air, compressed CO_2 and pumped storage. (Note that IPM has a separate category for existing pumped storage projects but does not have a category for any new non-battery storage technologies). In other words, IPM uses battery storage as a surrogate for all long term storage and does not explicitly model other technologies where projects are currently under development in the U.S., including pumped hydro, compressed air storage and compressed CO_2 storage.

Several manufacturers have already completed (and are in some cases are expanding) long term battery storage production facilities. Form Energy recently completed its Form Factory 1 and is moving towards production.[348] Form has already begun expansion of the factory with an

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343 Vineyard Wind, "Nation's first commercial-scale offshore wind project," *https://www.vineyardwind.com/vw1-1*.
344 The New Bedford Light, "When will Vineyard Wind be finished," November 26, 2024, *https://newbedfordlight.org/when-will-vineyard-wind-be-finished/*.
345 Renewable Energy World, "Empire 1 Secures $3 Billion Financing Package, Enters Full Execution Mode," January 3, 2025, *https://renewableenergyworld.com/wind-power/offshore/empire-wind-1-secures-3b-financing-package-enters-full-execution-mode/*.
346 Environmental Science Associates (ESA), "Charged Up: Battery Storage Demand Continues," December 12, 2024, *https://esassoc.com/news-and-ideas/2024/12/charged-up-battery-storage-demand-continues/*.
347 Kentucky Lantern, "Shelby County utility-scale battery manufacturing plant expected to create over 1,500 jobs," November 15, 2024, *https://kentuckylantern.com/2024/11/15/transformative-shelby-county-utility-scale-battery-manufacturing-plant-expected-to-create-over-1500-jobs/*.
348 Form Energy, "Form Factory 1," *https://formenergy.com/form-factory-1/*.

intention of having a 500 MWh production capacity by 2028.[349] Form has begun construction of its first storage facility, a 1.5 MW, 100 hour battery in Minnesota.[350] Form Energy is developing projects with multiple other utilities including an 85 MW, 100 hour battery in Lincoln Maine.[351] EOS has developed a 3 to 12 hour zinc based battery and just completed construction on its first manufacturing line with a current capacity of 1.25 GWh (1.25 GWh capacity allows for annual production of 100 MW of 12 hour battery capacity) and plans to expand it to 2 GWh[352]. EOS has secured a loan from DOE that will be used to expand capacity to 8 GWh by 2027.[353] This would give EOS a capacity of over 600 MW capacity of production. This would mean that these two companies alone could produce more than 1 GW of long term energy storage per year.

There are multiple other long term energy storage technologies and projects under development. For instance, Hydrostor is developing a compressed air storage system. Its first U.S. project, a 500 MW/8 hour system is projected to come on-line in 2030. Alliant Energy is working with Energy Dome to build the first U.S. compressed CO_2 storage project, a 20 MW, 10 hour facility. It is scheduled to come on-line in 2027[354]. Multiple U.S. pumped hydro projects are also under development. These projects tend to be larger, but also involve a lengthier permitting process. The National Hydropower Association indicates that there are 67 projects across 21 states with over 50 GW of potential capacity under various stages of development.[355] Several projects with near term development potential include the following:

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349 Form Energy, "Form Energy Begins Expansion of Form Factory 1 to Increase Manufacturing Capacity," October 14, 2024, *https://formenergy.com/form-energy-begins-expansion-of-form-factory-1-to-increase-manufacturing-capacity/.*
350 Form Energy, "Great River Energy and Form Energy break ground on first-of-its-kind multi-day energy storage project," August 15, 2024, *https://formenergy.com/great-river-energy-and-form-energy-break-ground-on-first-of-its-kind-multi-day-energy-storage-project/*.
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353 Eos Energy, "Eos Energy Closes $303.5 Million Loan Guaranteed by the U.S. Department of Energy to Support Project AMAZE and American Made Manufacturing Expansion," December 3, 2024, *https://www.eose.com/eos-energy-closes-303-5-million-loan-guaranteed-by-the-u-s-department-of-energy-to-support-project-amaze-and-american-made-manufacturing-expansion/.*
354 Wisconsin Public Radio, "First of its kind 'energy dome' storage project takes another step forward in Wisconsin," August 19, 2024, *https://www.wpr.org/energy/first-of-its-kind-energy-dome-storage-project-takes-another-step-forward-in-wisconsin*.
355 National Hydropower Association, "The Ultimate Water Battery: Unleashing The Power of Hydropower Energy Storage. Pumped Storage Industry Report," *https://www.nha2024pshreport.com/nha-psh-2024/.*

The Goldendale Energy Storage Project: In February, FERC issued a final EIS which recommended issuing a license for the 1200 MW/12 hour project with certain modifications.[356] The project developers are performing final design and engineering and with FERC approval, could begin construction in 2027 and commercial operation in 2032.[357]

The Lewis Ridge Pumped Hydro Project: In September, project developers submitted a draft license application to FERC in September 2024. Project developers anticipate that with FERC approval, they could begin construction by 2027.[358] The 287 MW/8 hour project could be on-line by 2031.[359]

Twelve States have energy storage mandates, goals or targets. Three contain explicit requirements for 8 hour+ storage. California has a mandate requiring 2 GW of long duration energy storage and 1 GW of multiday energy storage to be deployed between 2031-2037. Massachusetts has a target of 750 MW of long duration storage by 2030 and New York has a mandate for 1200 MW of long duration storage by 2030.[360]

VII. Virtual Power Plants

Virtual power plants (VPPs) are another way to address Petitioner's arguments concerning reliability related to load from variable emitting generation resources such as wind and solar. DOE explains that VPPs are "aggregations of distributed energy resources (DERs) such as smart appliances, rooftop solar with batteries, EVs and chargers and commercial and industrial loads that can balance electricity demand supply and provide grid services like a traditional power plant."[361] DERs are behind the meter (*e.g.*, customer owned) energy resources that can be integrated into the grid to smooth out peaks in electricity load. These distributed resources can either be resources that supply electricity (*e.g.*, residential or commercial solar/battery installations or power from a charged EV), or demand side resources that may have the ability to shift the timing of the demand (*e.g.*, shift using electricity from the grid during a period of high demand to a period of lower demand). Examples include smart thermostats, smart chargers and commercial or industrial loads.

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356 Federal Energy Regulatory Commission, "The Final EIS for the Goldendale Energy Storage Project (P-14861-002)," February 8, 2024, *https://www.ferc.gov/news-events/news/final-eis-goldendale-energy-storage-project-p-14861-002*.
357 *Id*.
358 Lewis Ridge Pumped Storage Project, "Lewis Ridge Advances with FERC Draft License Application," *https://lewisridgeproject.com/lewis-ridge-advances-with-ferc-draft-license-application.html.*
359 Lewis Ridge Pumped Storage Project, "A Bright Energy Future for Southeastern Kentucky," *https://lewisridgeproject.com/project.html*.
360 Clean Energy States Alliance, "Table of State Energy Storage Targets and Progress," *https://www.cesa.org/projects/energy-storage-policy-for-states/table-of-state-targets/*.
361 U.S. Department of Energy, "Pathways to Commercial Liftoff, Virtual Power Plants," September 2023, *https://liftoff.energy.gov/wp-content/uploads/2023/10/LIFTOFF_DOE_VVP_10062023_v4.pdf.*

While some characteristics of these resources may be modeled in the electric demand projections that EPA uses (*e.g.*, assumptions about lower demand to the grid because of behind the meter generation from solar/battery installations or increased demand from increased penetration of EVs), the potential flexibilities these offer to the grid and the impact they may have on the need to install new grid scale generation resources is not modeled in IPM. Much like energy storage, VPPs help address the intermittency of certain renewable technologies, which allows more of those technologies to be installed on the grid. In addition, VPPs can reduce peak demand, so that less new utility scale generation needs to be built.

DOE explains that "VPPs are not new and have been operating with commercially available technology for years. Most of the 30-60 GW of VPP available today is in demand response programs that are used when bulk power supply is limited, these programs turn off or decrease consumption from DERs such as smart thermostats, water heaters and commercial and industrial heaters."[362] A much wider range of DERs are now being incorporated in VPP projects.

Green Mountain Power in Vermont has a 50 MW program that leverages residential battery installations. The program provides customers with backup power during extreme weather events, but also provides power to the grid during peak power events, obviating the need for more new generation[363]. Sunrun, a supplier of home solar/storage systems, has VPP projects in multiple states. In 2023, Sunrun was able to supply PG+E's California customers with 32 MW of peak power, and the program continues to expand.[364] Sunrun has a similar program in New York.[365]

DOE projects that U.S. VPP capacity could be expanded to 80 GW to 160 GW by 2030.[366]

[362] *Id.*
[363] Green Mountain Power, "GMP's Network of Stored Energy Supports New England Grid During Historic Total Eclipse While Reducing Costs for all GMP Customers," April 9, 2024, *https://greenmountainpower.com/news/gmps-network-of-stored-energy-supports-new-england-grid-during-historic-total-eclipse/.*
[364] Electrek, "Sunrun sets a record in California with the US's largest virtual power plant," May 9, 2024, *https://electrek.co/2024/05/09/sunrun-california-us-largest-virtual-power-plant/.*
[365] Sunrun Investor Relations, "Sunrun Builds and Operates New York's Largest Residential Power Plant in Partnership with Orange and Rockland Utilities," October 23, 2024, *https://investors.sunrun.com/news-events/press-releases/detail/328/sunrun-builds-and-operates-new-yorks-largest-residential.*
[366] U.S. Department of Energy, "Pathways to Commercial Liftoff – The pathway to: Virtual Power Plants Commercial Liftoff," *https://liftoff.energy.gov/vpp/.*