August 8, 2023

The Honorable Michael Regan
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Ave, N.W.
Washington, DC 20460

Re: EPA's Proposed Clean Air Act Section 111 Rules for Power Plants.
Docket No. EPA-HQ-OAR-2023-0072.

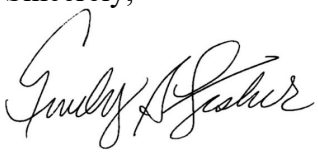
Dear Administrator Regan:

The Edison Electric Institute (EEI) appreciates the opportunity to comment on the U.S. Environmental Protection Agency's (EPA's or Agency's) proposed rules for regulating greenhouse gas (GHG) emissions for the power sector under the Clean Air Act (CAA), *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 111 Rules). 88 *Fed. Reg.* 33,240 (May 23, 2023). The Proposed 111 Rules would directly regulate GHG emissions from new natural gas-based units while also setting guidelines for the states to address emissions from existing coal- and natural gas-based units.

EEI members are united in their commitment to get the energy they provide as clean as they can as fast as they can, while keeping reliability and affordability front and center, as always, for the customers and communities they serve. Across the nation, EEI members are leading a clean energy transformation, making significant progress to reduce GHG emissions, while also creating good-paying jobs and an equitable clean energy future.

EEI appreciates the opportunity to continue to actively and constructively engage with EPA on the agency's full suite of climate and environmental regulations for power plants. We look forward to engaging with you and your team on these issues as the Agency works to finalize the Proposed 111 Rules. Please contact Alex Bond at abond@eei.org (202-508-5523) if you have any questions regarding EEI's comments.

Sincerely,



Emily Sanford Fisher
Executive Vice President, Clean Energy
General Counsel & Corporate Secretary

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Docket No. EPA-HQ-OAR-2023-0072

August 8, 2023

The Edison Electric Institute (EEI) appreciates the opportunity to comment on the U.S. Environmental Protection Agency's (EPA's or Agency's) proposed rules for regulating greenhouse gas (GHG) emissions for the power sector under the Clean Air Act (CAA), *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 111 Rules). 88 *Fed. Reg.* 33,240 (May 23, 2023). The Proposed 111 Rules would directly regulate GHG emissions from new natural gas-based units while also setting guidelines for the states to address emissions from existing coal- and natural gas-based units.

EEI is the association that represents all U.S. investor-owned electric companies. EEI's member companies provide electricity for nearly 250 million Americans and operate in all 50 states and the District of Columbia. The electric power industry supports more than 7 million jobs in communities across the United States. EEI's member companies invest more than $140 billion each year, on average, to make the energy grid smarter, cleaner, more dynamic, more flexible,

and more secure; to diversify the nation's energy mix; and to integrate new technologies that benefit both customers and the environment.

EEI's member companies are leading a profound, long-term transformation in how electricity is generated, transmitted, and used. This clean energy transition already has resulted in significant GHG emissions reductions, as EPA has recognized, and more than 40 percent of our nation's electricity now comes from clean, carbon-free sources.

EEI's member companies are committed to getting the energy they provide as clean as they can as fast as they can, while keeping customer reliability and affordability front and center. Across the industry, electric companies are investing in a broad range of carbon-free technologies and approaches, with the goal of demonstrating these technologies so that they can help further reduce power sector emissions when they satisfy industry performance requirements and are affordable for customers.

Electric companies and EPA agree on the long-term clean energy vision for the sector that is embodied in the Proposed 111 Rules: electric companies have reduced and will continue to reduce GHG emissions and will use emerging technologies to reduce emissions from new and existing fossil-based generation. Importantly, there are portions of EPA's rulemaking that provide a positive framework for this continued progress.

While there are challenges presented by the Proposed 111 Rules, these challenges are technical in nature. EEI and our member companies share EPA's goals of continuing to reduce emissions from the power sector and of achieving an economy-wide clean energy transition.

As we outline in these comments, electric companies are not confident that the new technologies EPA has designated to serve as the basis for proposed standards for new and existing fossil-based generation will satisfy performance and cost requirements on the timelines that EPA projects. This will impact electric companies' efforts to deliver affordable and reliable electricity to customers. These comments seek to provide perspectives on the Proposed 111 Rules such that any final rules provide durable regulatory frameworks that allow electric companies to continue to provide customers with the resilient clean energy they need and deserve, without compromising affordability.

I. Introduction and Summary of Comments.

As many EEI member companies are owners and operators of the new and existing fossil-based electric generating units (EGUs or units) that will be regulated by any final rules, they are uniquely qualified to provide feedback on EPA's proposals. EEI and its member companies actively have engaged with EPA on the full suite of climate and environmental regulations for power plants, including by filing extensive comments in the non-regulatory docket that preceded this rulemaking and by responding to proposals across the suite of environmental regulations, as well as through numerous meetings with EPA at all levels. EEI's member companies look forward to continuing to engage productively with EPA as the Agency works to finalize the Proposed 111 Rules.

EEI's member companies also are committed to developing and deploying emerging technologies, such as carbon capture and storage (CCS), hydrogen blending, small modular nuclear reactors, advanced renewables, energy storage, long-duration energy storage, and renewable natural gas, among other technologies. The successful development and deployment of these 24/7 technologies, along with the continued deployment of wind and solar generation and the operation of the existing nuclear fleet, will be necessary to achieve continued emissions reductions across the power sector and individual electric company commitments to reduce emissions to zero or net zero. They also will contribute to the reliability and resilience of an energy grid that is increasingly dependent on variable renewable generation.

The programs, funding, and tax incentives for new, clean technologies recently provided by Congress will be instrumental in driving the research, development, and demonstration necessary to make deployment of these technologies a reality. EEI's member companies already are working with the U.S. Department of Energy (DOE) and other agencies to move forward with critical demonstration projects and have received some of the project funding awards that DOE has given to date.

Consistent with electric companies' engagement with EPA and technology demonstration efforts, these comments are aimed at ensuring final standards are aligned with other regulations and their compliance timelines; afford states maximum flexibility so that they can work with unit owners and operators on affordable, reliable compliance options for all existing units; and provide a regulatory framework that supports continued industry investment in the clean energy transition. This will allow electric companies to make fully informed decisions about retiring older assets,

bringing on more new, cleaner sources of generation, and building the infrastructure to support the transformation to a resilient clean energy future for all customers.

The Proposed 111 Rules are an important piece of the regulatory framework that could support the power sector's continuing clean energy transformation, including the deployment of new clean technologies. These comments identify where the Proposed 111 Rules support the transition, how they could be better structured to support affordability and reliability for customers, and where compliance flexibilities and other tools will be needed, especially if EPA chooses to finalize the proposed standards without modification. To the extent possible, these comments propose solutions that EPA should adopt in any final 111 Rules.

A. EPA Should Finalize Key Elements of the Proposed 111 Rules and Consider Other Changes That Would Help Electric Companies Comply.

These comments identify technical and legal issues raised by EPA's proposals. Regardless of how EPA chooses to address these issues, EPA must design final standards for all regulated units that allow for compliance. Key design elements that EPA incorporated into the Proposed 111 Rules—which include the use of subcategories and significant compliance flexibility for states and units—should be finalized consistent with the technical, legal, and policy recommendations set forth in these comments. EPA also should consider expanding the proposed design and compliance flexibilities and making other important changes to the proposed standards to support compliance.

Final 111 Rules should:

- Set achievable, efficiency-based standards for new natural gas-based units, consistent with EEI's February 2023 recommendation to the Agency that these units be "capable" of

future retrofit to install CCS or blend hydrogen when those technologies are demonstrated and available at costs that are affordable for customers;

- Allow states to recognize changes to how existing units will be operated in the future and the emissions benefits of retiring existing units through appropriate subcategories—for both existing coal- and natural gas-based EGUs;

- Affirmatively allow states to adopt mass-based compliance approaches for both new and existing units;

- Provide states additional flexibility on the timing for state plan development and submittal to EPA; and,

- Provide units with dual-pathway approaches, which recognize that planning for new technologies during the short window for state plan development will be challenging, and provide a less prescriptive approach to the increments of progress to support these more flexible approaches.

These key program design elements and compliance flexibilities, along with the others discussed in these comments, will enable states and electric companies to implement final standards that are achievable, reliable, and affordable. In addition, EPA should be clear that the Agency will exercise considerable enforcement discretion for units that may install (or attempt to install) and use new technologies—like CCS or hydrogen blending—if those do not perform as expected or are not available on the timelines EPA predicts.

B. EEI's Member Companies Continue to Lead the Clean Energy Transition.

EEI's member companies are leading a profound, long-term transformation in how electricity is generated, transmitted, and used. This transformation is being driven by a wide range of factors, including relatively lower prices for natural gas, particularly as compared to historic high prices; increased deployment of renewable energy resources, energy efficiency measures, and demand-side management; technological improvements; changing customer, investor, and owner expectations; federal and state regulations and policies; legislation, including the Infrastructure

Investment and Jobs Act[1] (IIJA) and Inflation Reduction Act of 2022[2] (IRA); and the increasing use of distributed energy resources. Across the industry, electric companies are investing in a broad range of affordable, carbon-free technologies and approaches with the goal of finding the most cost-effective ways to deliver resilient clean energy.

The mix of resources used to generate electricity in the United States has changed dramatically over the last decade and is increasingly clean.[3] In 2022, for the first time, renewable energy sources[4] surpassed coal as a generation resource: 22.6 percent of total generation at utility-scale facilities in the United States came from renewable sources compared to 19 percent from coal-based generation.[5] In total, more than 40 percent of America's electricity came from clean carbon-free resources in 2022, including nuclear energy, hydropower, solar, and wind,[6] putting

[1] Pub. L. No. 117-58.

[2] Pub. L. No. 117-169.

[3] *See* U.S. Energy Information Administration (EIA), Today in Energy: Renewable generation surpassed coal and nuclear in the U.S. electric power sector in 2022 (Mar. 27, 2023), https://www.eia.gov/todayinenergy/detail.php?id=55960&src=email; *See also* EIA, Electric Power Monthly: Data for February 2023—Table 1.1 Net Generation by Energy Source: Total (All Sectors), 2013-February 2023 (Mar. 24, 2023), https://www.eia.gov/electricity/monthly/xls/table_1_01.xlsx; *and* EIA, Electric Power Monthly: Data for February 2023—Table 1.1.A. Net Generation from Renewable Sources: Total (All Sectors) (Mar. 24, 2023), https://www.eia.gov/electricity/monthly/xls/table_1_01_a.xlsx.

[4] Renewables here include wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, hydroelectric conventional, solar thermal, photovoltaic energy, solar, and wind. *See* EIA, Electric Power Monthly, Table 1.1, *supra,* n.3.

[5] *See id*.

[6] *See id.*

clean resources at parity with natural gas generation, which provided approximately 40 percent of the country's total electricity generation in 2022.

As part of the move toward resilient clean energy, electric companies are deploying more energy storage, which is a key asset that helps integrate increasing amounts of renewables into the energy grid while also enhancing resilience and reliability. Electric companies are the largest users and operators of the approximately 32 gigawatts (GW) of operational storage in the country—representing 93 percent of active energy storage projects.[7]

Going forward, renewable and clean energy technology deployments will continue. EIA predicts that declining capital costs for solar panels, wind turbines, and battery storage, along with government support such as that provided through the IRA, will make these technologies increasingly cost-effective compared to the alternatives when building new power generating capacity.[8] EIA projects that renewable generation in the United States will more than triple by 2050, with both wind and solar responsible for most of the growth.[9]

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[7] Compiled from the following proprietary sources: Wood Mackenzie Power & Renewables/American Clean Power Association, *U.S. Energy Storage Monitor* (2022); Dep't of Energy, *Energy Storage Database* (2022); Hitachi Energy, *The Velocity Suite Database* (2022).

[8] *See* EIA, Annual Energy Outlook 2023 (AEO 2023) 9 (Mar. 16, 2023), https://www.eia.gov/outlooks/aeo/pdf/AEO2023_Narrative.pdf.

[9] *See* AEO 2023—Table 16. Renewable Energy Generating Capacity and Generation: Electric Power Sector: Generation: Total (Mar. 16, 2023), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=16-AEO2023&region=0-0&cases=ref2023&start=2021&end=2050&f=A&linechart=ref2023-d020623a.25-16-AEO2023~&ctype=linechart&sid=ref2023-d020623a.25-16-AEO2023~ref2023-d020623a.64-16-AEO2023&sourcekey=0.

The changes in the mix of resources used to generate electricity have profoundly decreased the sector's carbon dioxide (CO_2) emissions, the primary GHG emissions associated with electricity production. EIA's preliminary full-year estimates for 2022 find that electric power sector CO_2 emissions were 36 percent below 2005 levels, as low as they were almost 40 years ago.[10] These reductions will continue.[11] Further, 50 EEI member companies have announced voluntary, forward-looking carbon reductions goals, 41 of which include a net-zero by 2050 or earlier equivalent goal, and member companies routinely increase the ambition or speed of their goals or altogether transform them into net-zero goals to reflect changing expectations about the cost and availability of renewable generation and other clean energy resources.

In addition, the electric power industry has significantly reduced emissions of traditional air pollutants, such as mercury, HAPs, sulfur dioxide (SO_2), and nitrogen oxides (NOx). As of 2022, SO_2 and NOx emissions have declined 95 and 88 percent, respectively, since 1990.[12] In addition, mercury emissions have declined by 95 percent since 2010,[13] and total HAPs—including all acid gas emissions—declined by 96 percent between 2010 to 2017.[14]

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[10] *See* EIA, Monthly Energy Review, Environment, Table 11.6—Electric Power Sector (Mar. 2023), https://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf.

[11] *See* AEO 2023 at 4.

[12] *See* EPA, Power Plant Emissions Trends (Feb. 2023), https://www.epa.gov/power-sector/power-plant-emission-trends.

[13] *See* EPA, Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards, page 2-7 (Dec. 2011), https://www.epa.gov/sites/default/files/2015-11/documents/matsriafinal.pdf.

[14] *See* 84 *Fed. Reg.* 2,670, 2,689 (Feb. 7, 2019).

EEI's member companies see a clear path to continued emissions reductions over the next decade using current technologies, including nuclear energy, natural gas-based generation, energy demand efficiency, energy storage, and deployment of new renewable energy—especially wind and solar[15]—as older coal-based and less-efficient natural gas-based generating units retire.[16] These technologies will continue to enable significant, cost-effective carbon reductions.

In the long term, reaching net-zero carbon emissions also will require the deployment of next-generation, carbon-free, 24/7, dispatchable technologies not currently available commercially. Supported by the clean energy tax incentives included in the IRA and the grant funding available via the IIJA, electric companies are partnering with technology developers, academic institutions, investors, philanthropists, each other, and other stakeholders to develop, demonstrate, and deploy these new clean energy technologies. These include long-duration energy storage, CCS, advanced nuclear and renewable generation, and clean fuels (like hydrogen, renewable natural gas, and ammonia). Developing and deploying a broad range of advanced clean energy technologies will further expedite the transition of the electric power sector to one that is low- or non-emitting while keeping electricity affordable and reliable for customers.

[15] Once built and when the resource is available, wind and solar are the least cost resources to operate to meet electricity demand because they have zero fuel costs. Over time, the combined investment and operating cost advantage increases the share of zero-carbon electricity generation. *See* AEO 2023 at 5.

[16] EIA notes that coal-based generation capacity will decline sharply by 2030 to about 50 percent of current levels (from about 200 GW to 100 GW) with a more gradual decline thereafter. *See* AEO 2023 at 13.

C. Best System of Emission Reduction Technologies Must Be Adequately Demonstrated in Order for Standards to Be Achievable.

EPA proposes to determine that the best system of emission reduction (BSER) is CCS for existing coal-based units and either CCS or hydrogen blending for new and existing natural gas-based turbines. In making these BSER determinations, EPA asserts that CCS and hydrogen blending are adequately demonstrated, that these technologies are affordable for customers, and that the resulting standards are achievable across the entire industry. Given the status of these technologies today and the uncertainty inherent in EPA's future projections—especially regarding the ability to deploy the needed infrastructure that complements these technologies across the industry in a timely fashion—EPA's assessments are not legally or technically sound based on the record before the Agency.

As discussed in these comments, EPA's rulemaking record simultaneously downplays the various infrastructure challenges to deploying these technologies, while overplaying the current state of deployment and demonstration of each technology. Given these realities, neither CCS nor hydrogen blending are adequately demonstrated today as they are not deployable, available, or affordable across the entirety of the industry, and the attendant supporting infrastructure will take more time than EPA predicts to deploy. This assessment factors in the timelines that EPA proposes for standards that may not be applicable until several years in the future. Accordingly, unit owners and operators have significant concerns about the achievability of the proposed standards.

EEI's member companies are working to demonstrate these critical technologies and intend to use them when they satisfy customer cost and industry performance requirements. In the interim,

and even with emissions standards in place, it is not at all certain that state utility commissions will approve plans, which would need to be made well before compliance deadlines, to allocate capital—and impose risk and cost-recovery burdens on customers—for unproven technologies. It is similarly uncertain that electric companies will be able to obtain private financing for technologies that do not have a clear ability to meet regulatory standards, particularly given the possibility of CAA enforcement penalties. As a result, standards that require these technologies for compliance are not likely to drive the deployment necessary to improve performance and bring down costs, but instead could slow down key projects as EEI's member companies work to deploy demonstration projects and related infrastructure over the next decade and beyond. Similarly, unachievable standards could delay deployment of new generation, particularly new natural gas generation, that will be needed to serve customers reliably and affordably this decade.

EPA should not finalize the phased standards that are based on CCS or hydrogen blending as BSER given these concerns. If EPA moves forward with the standards as proposed, however, the Agency should provide electric companies and states as much compliance flexibility as possible to address achievability concerns. EPA also should commit to providing significant enforcement discretion should these technologies not perform reliably or be available on the Agency's projected timeframes.

D. Organization of EEI's Comments.

EEI appreciates the opportunity to continue to actively and constructively engage with EPA on the Agency's full suite of climate and environmental regulations for power plants. EEI has provided significant feedback in the form of whitepapers addressing the waterfront of potential programmatic elements of what became the Proposed 111 Rules. Those whitepapers are attached

to these comments as Appendices A, B, and C. Several of the recommendations EEI made in those whitepapers, aimed at helping EPA to develop workable final standards, are reflected in parts of EPA's Proposed 111 Rules. EEI also outlined some concerns and anticipated technical challenges expected in the Proposed 111 Rules in those whitepapers. Some of those concerns remain and are addressed below.

Section II of these comments addresses the proposed retirement subcategories, noting that these approaches are consistent with many of the trends in the sector regarding already planned unit retirements and will be beneficial for many companies and their customers. This section also provides suggested improvements to the design of these subcategories and additional policy and legal rationales for EPA's approach. It identifies potential unintended consequences that flow from the proposed approach to existing natural gas-based units and seeks additional, tailored flexibilities for these units and the states that will regulate them. Section III addresses concerns regarding EPA's determination that CCS technology is adequately demonstrated as BSER, focusing on the Agency's technical judgments and record. Section IV does the same for EPA's determination that hydrogen blending is BSER for both new and existing natural gas-based units.

Section V provides feedback on EPA's proposed efficiency standards and subcategories for new natural gas-based units with a focus on achievability and compliance flexibility for these units. Section VI addresses numerous suggested state plan flexibilities that can help the states submit, and EPA approve, compliance plans that allow companies to reduce emissions in a reliable and affordable manner. Section VII addresses certain applicability concerns raised by EPA's proposal.

II. EPA's Use Of Subcategories Is Well Supported And Should Be Strengthened And Expanded.

EPA proposes to utilize numerous subcategories for both new natural-gas based units and, crucially, for existing coal-based units. Three of the proposed subcategories for coal-based units include retirement options tied to specific retirement deadlines. Units that opt into these subcategories agree to a shutdown commitment, which becomes federally enforceable once it is included in a state's compliance plan, in exchange for less stringent emissions limitations prior to closure. *See* 88 *Fed. Reg.* at 33,341. For new natural gas-based units, EPA divides those units into three subcategories based on utilization: base load, intermediate load, and low load. *See id.* at 33,277.

EPA has clear authority to utilize subcategories, and the approach to subcategories in the Proposed 111 Rules is well-founded. EPA should, however, include in any final rules the alternative rationale that the subcategories for existing coal-based units also are a permissible use of a state's ability to utilize the statutory authority under the CAA's remaining useful life and other factors (RULOF) provisions. EPA's proposed subcategories, therefore, also represent a presumptively approvable approach for states' exercise of their statutory authority to consider RULOF when setting standards for existing units. Further, EPA should make several additional changes to the proposed subcategories in order to allow for additional flexibility and ensure that states and units can continue to plan for the operation of an affordable and reliable energy grid in transition. EPA also must provide similar subcategorization approaches for existing natural gas-based units, since these units are similarly situated to coal-based units in the value they provide to the system, and the Agency should treat them as such. Failure to do so would be arbitrary.

A. EPA's Use of Subcategories is Well-Supported.

While EPA included performance standards in the Proposed 111 Rules for fossil fuel types other than coal (i.e., natural gas- and oil-fired steam generating units), the largest category regulated will be coal-fired steam generating units. EPA proposed to "divide the subcategory for coal-fired units into additional subcategories based on operating horizon (i.e., dates for electing to permanently cease operation) and, for one of those subcategories, load level (i.e., annual capacity factor), with a separate BSER and degree of emission limitation corresponding to each subcategory." 88 *Fed. Reg.* at 33,341. The Proposed 111 Rules acknowledge that many existing coal plants may retire within coming years, such that the cost-effectiveness of installing pollution controls will depend on a power plant's operating horizon.[17] Thus, EPA proposes an emission limit based on 90 percent CCS for coal-fired units that plan to continue operating past January 2040, with less stringent standards for units that commit to an earlier, enforceable retirement date.[18]

1. EPA has clear authority to subcategorize on a plain reading of section 111.

[17] In general, EPA's assessment that many coal-based units will retire between now and 2040 tracks general trends in the industry; however, each individual facility and company faces unique circumstances and individual unit retirement decisions are complex undertakings given the unique value each plant can provide to the operation of the grid.

[18] As discussed, *infra*, while EPA has the authority under section 111 to subcategorize based on retirement horizon (for existing sources) and load level (for both new and existing sources), for both new and existing sources EPA only has authority under section 111 to select a BSER that has been adequately demonstrated *now*. That the statute provides EPA some authority to allow existing sources time to *implement* BSER following promulgation of final rules does not change that, since that authority is there to ensure that the absence of emission control while the control technology is installed (which may itself take years) does not put the source in a state of noncompliance. EPA cannot "project" that a control technology will be available at some future point.

For existing coal-based units, EPA proposed to align BSER with the planned retirement dates of the units pursuant to state plans. *See* 88 *Fed. Reg.* at 33,341. EPA has wide discretion under CAA section 111(b)(2) to "distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing [new source] standards," which is referred to as "subcategorizing." *See* 42 U.S.C. § 7411(b)(2); *see also Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) (per curiam); *Sierra Club v. Costle*, 657 F.2d 298, 318-19 (D.C. Cir. 1981). CAA section 111(d)(1) provides a similarly broad grant of authority to EPA, directing it to "prescribe regulations which shall establish a procedure…under which each State shall submit to the Administrator a plan [with standards of performance for existing sources.]"[19] The subcategorization authority given EPA in CAA section 111(b)(2) has been interpreted to apply as well to section 111(d) and allows EPA to place existing sources into subcategories when these sources have characteristics that are relevant to the controls that EPA may determine to be the BSER that has been adequately demonstrated.[20]

Further buttressing the notion that EPA has authority to subcategorize existing sources under section 111(d) is the language governing the plans that EPA is required to promulgate to regulate

[19] Regardless of whether EPA subcategorizes within a source category for purposes of determining the BSER and the emission performance level for the emission guideline, a State retains certain flexibility in assigning standards of performance to its affected EGUs.

[20] Conversely, subcategorization is not appropriate for a set of sources where the qualities in common are not relevant for determining what controls are appropriate to reduce emissions. EPA finds this view is consistent with the D.C. Circuit's interpretation of CAA section 112(d)(1), which is a subcategorization provision that is substantially similar to CAA section 111(b)(2). *See NRDC v. EPA*, 489 F.3d 1,364, 1,375–76 (D.C. Cir. 2007) (upholding EPA's decision under CAA section 112(d)(1) *not* to subcategorize sources subject to control requirements under CAA section 112(d)(3), known as the maximum achievable control technology (MACT) floor, on the basis of costs because the EPA was not authorized to consider costs in setting the MACT floor).

existing sources within a State should a State fail to submit its own plan. CAA section 111(d)(2) provides that, in promulgating such a plan, EPA "*shall* take into consideration, among other factors, remaining useful lives of the sources in the category to which such standard applies [emphasis added]." Thus, Congress has expressly contemplated that existing sources might be subcategorized, by EPA, under section 111(d) based on the anticipated length of their continued operation.

Since the 1970s, EPA has developed subcategories in several rulemakings under CAA section 111. These rulemakings include subcategories on the basis of unit characteristics, including: the size of the sources;[21] the types of fuel combusted;[22] types of equipment used to produce products;[23] types of manufacturing processes used to produce product;[24] levels of utilization of

[21] *See* 40 C.F.R. § 60.40b(b)(1)-(2) (subcategorizing certain coal-fired steam generating units on the basis of heat input capacity).

[22] *See Sierra Club v. EPA*, 657 F.2d 298, 318-19 (D.C. Cir. 1981) (upholding a rulemaking that established different NSPS "for utility plants that burn coal of varying sulfur content"); *see also* 2015 NSPS, 80 *Fed. Reg.* 64,510, 64602 (table 15) (Oct. 23, 2015) (subdividing new combustion turbines on the basis of type of fuel combusted).

[23] *See* 81 *Fed. Reg.* 35,824 (June 3, 2016) (promulgating separate NSPS for many types of oil and gas sources, such as centrifugal compressors, pneumatic controllers, and well sites).

[24] *See* 42 *Fed. Reg*. 12,022 (Mar. 1, 1977) (announcing availability of final guideline document for control of atmospheric fluoride emissions from existing phosphate fertilizer plants); *see also* "Final Guideline Document: Control of Fluoride Emissions From Existing Phosphate Fertilizer Plants, EPA-450/2-77-005 1-7 to 1-9, including table 1-2 (applying different control requirements for different manufacturing operations for phosphate fertilizer).

the sources;[25] the activity level of the sources;[26] and geographic location of the sources.[27] EPA's proposed subcategorization based on length of period of continued operation is similar to two other instances for subcategorization on which EPA has relied in prior rules regarding load level and fuel type.

First, in the 2015 New Source Performance Standard (NSPS), EPA subcategorized new natural gas-fired combustion turbines into subcategories of base load and non-base load. *See* 80 *Fed. Reg.* at 64,602. In that instance, EPA determined the control technologies were "best" because consideration of feasibility and cost-reasonableness depended on how much the unit operated. The load level, which relates to the amount of product produced on a yearly or other basis, is similar to the limits on a period of continued operation in the Proposed 111 Rules, which concerns the amount of time remaining to produce the product. Further, in both instances, certain technologies may not be cost-reasonable because of the capacity to produce product.

Second, also in the 2015 NSPS, EPA divided new combustion turbines into subcategories based on fuel type combusted. *See id*. There, the Agency determined that the cost-reasonableness of the

[25] *See* 2015 NSPS, 80 *Fed. Reg*. 64,510, 64,602 (table 15) (Oct. 23, 2015) (dividing new natural gas-fired combustion turbines into the subcategories of base load and non-base load).

[26] *See* 81 Fed. Reg. 59,276, 59,278-79 (Aug. 29, 2016) (dividing municipal solid waste landfills into the subcategories of active and closed landfills).

[27] *See* 71 Fed. Reg. 38,482 (July 6, 2006) (SO_2 NSPS for stationary combustion turbines subcategorizes turbines on the basis of whether they are located in, for example, a continental area, a non-continental area, the part of Alaska north of the Arctic Circle, and the rest of Alaska); *see also Costle*, 657 F.2d at 330 (stating that the EPA could create different subcategories for new sources in the Eastern and Western U.S. for requirements that depend on water-intensive controls).

control depended on the type of fuel combusted. This is similar to the Proposal's subcategorization on the basis of length of period of continued operation because, in both cases, the subcategory is based upon the reasonableness of controls. Subcategorizing based on the duration of continued operation also depends on the span of time in which the fuel will continue to be combusted, because the cost-reasonableness of this approach depends on the length of that timeframe. *See* 88 *Fed. Reg.* at 33,345, explaining that prior EPA rules for coal-fired sources explicitly link length of time for continued operation and fuel type combusted by codifying retirement dates by which the sources must "cease burning coal," citing 79 *Fed. Reg.* 5,032, 5,192 (Jan. 30, 2014).

EPA's authority to consider cost likewise supports its authority to subcategorize based on retirement date. EPA's longstanding implementing regulations explicitly recognize that subcategorization may be appropriate for sources based on "costs of control." *See* 40 C.F.R. §§ 60.22(b)(5), 60.22a(b)(5). EPA maintains that its authority to subcategorize on the basis of federally enforceable dates for permanently ceasing operations "is consistent with a central characteristic of the coal-fired power industry that is relevant for determining the cost reasonableness of control requirements." 88 *Fed. Reg*. at 33,345. Since many EEI's member companies can choose to retire these units and cease operations in response to this rulemaking and other factors, that implicates EPA's determination as to what controls are "best" for different subcategories. EPA's Proposal correctly reflects that cost of controls and length of operation are inextricably intertwined in evaluating BSER for existing sources, because whether costs are reasonable depends in part on the period of time which the affected sources can amortize those

costs. EPA's Proposal to reflect retirement date in the subcategorization for existing source BSER thus is reasonable.

2. EPA has utilized retirement-based approaches in other CAA programs.

In another CAA example, the regional haze program, EPA has utilized its discretion to allow units that are retiring to forgo installation of control technology that would otherwise be required under an analysis of Best Available Retrofit Technology (BART) or the necessary level of control to ensure reasonable progress toward the long-term goal of the regional haze program. The CAA requires each regional haze plan to "contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress" toward the statutory goal of eliminating manmade visibility impairment in Class I Federal areas.[28] When determining what measures amount to "reasonable progress" a State must consider four criteria: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and nonair quality environmental impacts of compliance; and (4) the remaining useful life of any existing source subject to such requirements.[29]

[28] *See* 42 U.S.C. § 7491(b)(2).

[29] *Id.* at 42 U.S.C. § 7491(g)(1). To ensure states achieve "reasonable progress," every plan must require certain large-scale, stationary sources of air pollutants to implement controls known as BART, or adopt a BART alternative. *Id.* at § 7491(b)(2)(A); 40 C.F.R. § 51.308. The CAA defines BART as being based on a source-specific evaluation of five factors. *See Oklahoma v. EPA*, 723 F.3d 1201, 1208 (10th Cir. 2013). These "BART factors" are:

(1) The costs of compliance;
(2) The energy and non-air quality environmental impacts of compliance;
(3) Any existing pollution control technology in use at the source;
(4) The remaining useful life of the source; and,
(5) The degree of visibility improvement which may reasonably be anticipated from the use of BART.

42 U.S.C. § 7491(g)(2).

While the regional haze program focuses on source-specific evaluations of the BART factors during the first planning period, it is notable that EPA and states have concluded, in numerous different contexts, that an evaluation of all of the factors listed above leads to the imposition of no further controls given the pending retirement of the source in question. This has primarily been the result of an analysis of the remaining useful life of the source when weighed against the other four BART factors—specifically, that the installation of pollution control technology can impose significant costs for some environmental gains, but that those costs and environmental benefits do not outweigh the environmental and economic benefits of simply retiring the source.[30]

3. EPA has used retirement subcategories in other environmental rulemakings for the power sector.

Courts have long recognized that EPA has broad discretion in determining how to evaluate and weigh these factors. *See, e.g.*, *Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 928 (5th Cir. 1998) ("The EPA nonetheless has considerable discretion in evaluating the relevant factors and determining the weight to be accorded to each in reaching its ultimate BAT determination. EPA's authority under the CWA to subcategorize is analogous to that of the CAA. For example, EPA has ample legal authority to establish (or revise) retirement subcategories when promulgating

[30] EPA has endorsed such an approach in its approval of Arkansas' Regional Haze State Implementation Plan and withdrawal of a Federal Implementation Plan wherein the Agency determined that there was no need to install pollution control technology on BART eligible units given that those units had an enforceable order to switch the type of coal used and then to cease use off coal by the end of 2028. *See* Approval and Promulgation of Implementation Plans; Arkansas; Approval of Regional Haze State Implementation Plan Revision for Electric Generating Units in Arkansas, 84 *Fed. Reg.* 51,033 (Sept. 27, 2019). Specifically, EPA concluded that Arkansas satisfied the requirements of the CAA by "fully considering the five statutory factors…Taking into account the remaining useful life of White Bluff Units 1 and 2 (based on Entergy's enforceable Administrative Order to cease coal combustion by December 31, 2028), and the resulting cost-effectiveness of controls, as well as the anticipated visibility improvement of the SO_2 control options and the other BART factors." *Id*. at 51,036.

effluent limitation guidelines (ELGs). In developing best available technology (BAT) limits, EPA must consider "the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements), and such other factors as the Administrator deems appropriate." 33 U.S.C. § 1314(b)(2)(B). Thus, the EPA has significant leeway in determining how the BAT standard will be incorporated into final ELGs."); *NRDC v. EPA*, 863 F.2d 1420, 1426 (9th Cir. 1988) ("EPA has considerable discretion in weighing the costs of BAT."); *Weyerhaeuser Co. v. Costle*, 599 F.2d 1011, 1046 (D.C. Cir. 1978) ("[T]he listing of factors seems aimed at noting all of the matters that Congress considered worthy of study before making limitation decisions, without preventing EPA from identifying other factors that it considers worthy of study. So long as EPA pays some attention to the congressionally specified factors, the section on its face lets EPA relate the various factors as it deems necessary.").

The same statutory factors that EPA must account for when developing BAT limits are relevant to the question of whether to subcategorize within a category of point sources.[31] Accordingly, it is unsurprising that courts have upheld EPA determinations to promulgate different limits for

[31] *See* 67 *Fed. Reg.* 42,644, 42,656 (June 24, 2002) ("The CWA requires EPA, in developing effluent limitation guidelines and pretreatment standards, to consider a number of different factors, which are also relevant for subcategorization."); *see also* 64 *Fed. Reg.* 2,280, 2,300-01 (Jan. 13, 1999) ("One way in which the Agency has taken some of these factors into account is by breaking down categories of industries into separate classes of similar characteristics. This recognizes the major differences among companies within an industry that may reflect, for example, different manufacturing processes, economies of scale, or other factors. One result of subdividing an industry by subcategories is to safeguard against overzealous regulatory standards, increase the confidence that the regulations are practicable, and diminish the need to address variations between facilities through a variance process.").

different subcategories or classes of sources within a particular point source category based on EPA's consideration of the statutory factors in CWA section 304(b).[32]

Of particular relevance here, the importance of evaluating the statutory age and cost factors, and how they affect economic achievability, cannot be overstated. EPA is required to "consider age as it might pertain to the cost or feasibility of retrofitting plants with new pollution control technology." *Am. Iron & Steel Inst. v. EPA*, 568 F.2d 284, 299 (3d Cir. 1977) (referencing the holding in *Am. Iron & Steel Inst. v. EPA*, 526 F.2d 1027, 1048 (3d Cir. 1975)). This may entail accounting for "the fact that all the plants within [a particular] subcategory were built long before plants in another subcategory [which can] present special problems in installing anti-pollution devices." 526 F.2d at 1048. "Similarly, in a subcategory where there is considerable variation in age, the fact that the processes are similar may mean that the same type of control technology can be installed, but it does not necessarily mean that the ease with which that technology can be installed, or the ability to comply with effluent limitations once it has been installed, is not affected by age." *Id*. Thus, EPA's approach on both ELGs here for existing sources is sound.

4. EPA should also conclude in the alternative that its retirement subcategories are optional compliance approaches that are equivalent to or more stringent than its CCS-based BSER determination.

In the Proposed 111 Rules for existing coal-based units, EPA proposes that each subcategory—imminent-, near-, medium- and long-term operating units—has its own specific BSER based on

[32] *See e.g.*, *Texas Oil & Gas Ass'n*, 161 F.3d at 939 (upholding EPA decision "to set more lenient effluent limits for Cook Inlet facilities than for other members of the Coastal Subcategory"); *BP Exploration & Oil, Inc. v. EPA*, 66 F.3d 784, 802 (6th Cir. 1995) (upholding EPA's rejection of zero discharge of drilling wastes in Alaska based on consideration of various factors, such as infeasibility of reinjection technology).

the characteristics of the units included. As discussed immediately *supra*, EPA is well justified in doing so. However, EPA should also conclude in the alternative that the retirement-based subcategories (imminent-, near-, and medium-term) are optional, compliance-based subcategorizations that are at a minimum equivalent if not more stringent in the aggregate than EPA's BSER determination for long-term units.

Such a determination would be consistent with EPA's ability to subcategorize under CAA section 111 and would also legally ensure that EPA's principal BSER determination was technological in nature since EPA's BSER determination would be singular and the subcategories would be optional, compliance options to comply with EPA's proposal. This would allow for retirement subcategories to be squarely within EPA's discretion from a compliance perspective. Under such an approach, EPA would not need to analyze all of the BSER factors described above to justify each subcategory individually, as the Agency's determination that the subcategory would result in equivalent or greater reductions would provide justification for each subcategory.

Such an approach also would be grounded in the statute, specifically CAA section 111(d)(1)(B), which allows the Administrator to take into consideration, among other factors, the "remaining useful life" of the existing source to which any standard applies. EPA should note that each retirement-based subcategory specifically relies on the language in section 111(d)(1)(B) as part of the Agency's ability to offer each subcategory. Such a conclusion flows logically from the statute. Each subcategory is already designed to take into account the remaining useful life of sources that are in each subcategory—to be eligible for the imminent-, near- or medium-term subcategory, a unit must have an enforceable shutdown commitment, and would have a standard

different from the one applied to long-term units (in the case of the current proposal, this would be CCS technology for existing coal-based units).

As noted, *supra*, this approach would be consistent both with EPA's approach to regional haze, and the ELG rulemaking under the CWA. This approach would also comport with EPA's proposed Section 111(d) implementing regulations for state plans, which EPA states are intended to "improve flexibility and efficiency in the submission, review, approval, revision, and implementation of state plans." 87 *Fed. Reg.* 79,176 (Dec. 23, 2022). Importantly, this compliance flexibility also reflects the "core principle of cooperative federalism" embedded in the CAA. *Miss. Comm'n on Envt'l. Quality v. EPA*, 790 F.3d 138, 156 (D.C. Cir. 2015); *Am. Lung Ass'n*, 985 F.3d at 420 (reiterating "the importance of allowing States maneuvering room under the cooperative federalism scheme"). Further, given the D.C. Circuit's decision in *American Lung Association* noting that EPA could offer significant compliance flexibility to states and units and was not required to have sources implement the specific BSER prescribed by EPA, the Agency would be well served to make this argument as an alternative basis for its proposal. 985 F.3d at 942-43, 963.

B. Subcategories Are Essential to Finalizing a Workable Rule for Existing Coal-Based Units and the Proposed Subcategories Must Be Retained in Any Final Rule.

For existing coal-based units, EPA proposes several subcategories. *See* 88 *Fed. Reg*. at 33,341. Three of the proposed subcategories are based on operating horizon and are tied to specific retirement deadlines, intended to reflect many of the already-announced retirements of coal-based EGUs. Units that opt into these subcategories agree to a shutdown commitment, which becomes federally enforceable once it is included in a state's compliance plan, in exchange for

lesser, and in some cases, effectively no, emissions limitations before closure. As proposed, facilities would be required to commit to a particular subcategory at the time that the relevant state submits its compliance plan to EPA. *See id*. at 33,344. These retirement subcategories recognize that the long-term emissions benefits of announced unit closures could be undermined by standards that would require owners/operators to invest in control technologies that could extend the lives of the units to ensure cost recovery. *See id*. at 33,341.

EPA's proposed retirement subcategories support ongoing power sector efforts to achieve significant and permanent emissions reductions, are well-founded, and should be included in any final rule. However, the proposed subcategories should be adjusted to address issues identified in these comments. The Agency should finalize this subcategory-based approach, with the changes suggested here.

1. EPA's use of retirement subcategories for existing coal-based units is broadly consistent with the power sector's ongoing transformation and EPA should finalize this approach.

The proposed retirement subcategories, as a general matter, track the ongoing clean energy transformation under way in the industry and allow companies to align retirements and investments in a way that balances reliability and affordability for customers should those decisions lead to a decision to retire a unit or units. Many of EEI's member companies are in the process of decommissioning or repowering existing coal-based EGUs, which will result in significant pollution reductions through avoided future emissions. Fifty of EEI's member companies have announced voluntary, forward-looking carbon reductions goals, 41 of which include a net-zero by 2050 or earlier equivalent goal, and members routinely increase the ambition or speed of their goals or altogether transform them into net-zero goals to reflect

changing expectations about the cost and availability of renewable generation and other clean energy resources.

As discussed above, EPA has created targeted subcategories for unit closures in other contexts, most notably the cessation of coal subcategory in the Proposed ELG Rule. *See* 85 *Fed. Reg.* 64,650 (Oct. 13, 2020); 88 *Fed. Reg.* 18,824 (Mar. 29, 2023). The subcategories allow for decommissioning/repowering of units, recognizing that standards requiring investments in new control equipment could extend the lives of these units to support cost recovery, and that unit retirements provide long-term environmental benefits through permanent closure and cessation of related emissions. Critically, retirement-based subcategories result in significant avoided future emissions, leading to greater overall reductions than those that could be expected from any existing source guidelines and/or state plans that only provide emissions limits for these units. EPA's proposed approach to these subcategories, therefore, is well-founded in terms of environmental benefits, and the Agency should include them in any final rule.[33]

2. EPA's proposed retirement dates for applicability of the various subcategories are appropriate and broadly consistent with system reliability needs; EPA should not accelerate the dates by which units must retire to access the subcategories.

EPA has proposed that the various retirement subcategories extend out until 2040 to track the industry's ongoing clean energy trends and announced retirement schedules of several EEI's member companies. *See* 88 *Fed. Reg*. at 33,343. Indeed, EPA says as much in the Proposed 111 Rules, noting that industry stakeholders—including EEI—recommended "that EPA allow

[33] As discussed, *supra*, EPA has clear authority to subcategorize units both in the setting of standards and for determining compliance. Importantly, retirement subcategories also are squarely consistent with states' authority to consider the remaining useful life when setting standards for existing units based on EPA's emissions guidelines.

existing sources that are on a path to near term retirement to continue on that path without having to install additional control equipment. The proposed emission guidelines are aligned with this recommendation…and [retirement plans] are part of utilities with commitments to net zero power by certain dates, or are in States or localities with commitments to net zero power by certain dates." *Id*. EPA notes further that over one-third of existing coal-based steam generating capacity has planned to cease operation by 2032, and approximately half of the capacity has planned to cease operations by 2040. *See id*.

The closure dates reflected in the proposed retirement subcategories broadly reflect the ongoing fleet transition writ large; electric company commitments, costs, and the other factors driving clean energy deployment are all playing a significant role in transforming the sector and reducing emissions. Crucially, the retirement dates for the subcategories chosen by EPA also generally align with the overall ability of the electric sector to retire these units in a manner consistent with reliable and affordable system operations; the time provided by EPA allows for coal-based capacity to remain available on the system in a manner that helps address changing system conditions given the integration of clean energy resources and increasing demand due to electrification. System operators across the country and the North American Electric Reliability Corporation (NERC), the designated electric reliability organization under the Federal Power Act, have assessed the potential for capacity shortfalls for the rest of this decade as the energy system continues the clean energy transformation. One cause of these capacity shortfalls is the difficulty of interconnecting new resources to the grid as a result of the growing number of new

sources seeking such interconnection and the increasing retirement of existing units.[34] In short, capacity additions (the vast majority of which are intermittent resources with lesser accredited capacity) are not keeping pace with capacity retirements. This presents significant near-term risks to system reliability, particularly during extreme events.[35] Allowing coal-based EGUs to be available throughout the rest of this decade and into the 2030s, therefore, is crucial to preparing for these events and for maintaining overall grid reliability.[36] On a more localized-level, many of the planned retirements that EPA notes in the proposed subcategories already are factored into company's long-term plans. The dates selected reflect their assessments by which these units can be reliably retired and correspond with the availability of other capacity or transmission solutions to replace that which is being lost. However, some of the dates EPA has proposed do not currently match the filed plans and projected availability of replacement capacity; as discussed, *infra*, EPA should note that states can alter the presumptive dates in the subcategories to take specific circumstances into account.

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[34] *See, e.g.*, NERC, 2023 Summer Reliability Assessment (May 17, 2023)(warning that two-thirds of North America would be at risk of energy shortfalls this summer in the event of widespread heatwaves), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf.

[35] *See* NERC, 2023 State of Reliability Technical Assessment, Technical Assessment of the 2022 Bulk Power System (June 2023), https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2023_Technical_Assessment.pdf

[36] For example, last year several units in Wisconsin last year delayed imminent planned closures for 18 months to ensure sufficient accredited capacity in MISO over the summer to prepare for peak demand. These delays promoted reliability and were still consistent with the owners'/operators' long-term clean energy goals. *See* Iulia Gheorghiu, Alliant, *We Energies Walk back Wisconsin Coal Retirement Plans in Light of MISO's Expected Capacity Shortfalls*, UTILITY DIVE (June 24, 2022), https://www.utilitydive.com/news/wisconsin-utilities-coal-retirement-miso-delay/626005/. Due to improved accreditation procedures and the interconnection of new generating resources, among other factors, MISO North's capacity situation was improved for the summer of 2023. The extended availability of these coal EGUs, therefore, provided an appropriate buffer while MISO implemented other reliability solutions.

Any movement of these dates forward in time (especially if EPA decides to limit post-2030 retirement options) would undermine significant time and investment in companies' clean energy transformation plans, which also factor in customer costs and which, in many instances, have already been approved by state regulators. Accordingly, in any final rule, EPA should not move these dates forward in time. The Agency's rationale for including these dates is that they closely track the industry's ongoing plans for unit closure and fleet transition and is a reasonable exercise of the Agency's discretion to subcategorize, as discussed in more detail *supra*. EPA's rationale is generally correct, and such an approach can help to support system reliability by ensuring that critical capacity is available over the next decade.

3. EPA can propose presumptively approvable retirement subcategories for existing units, but states have the authority to alter the closure deadlines for specific units based on each's remaining useful life.

EPA can provide presumptively approvable retirement subcategories for states to use in the CAA section 11 implementation plans. This is consistent with EPA's statutory obligations to provide states with emissions guidelines to use in setting standards for existing units under CAA section 111(d). *See* 42 U.S.C. § 7411(d). EPA recognizes both its role and the role of the states in setting standards for existing units throughout the Proposed 111 Rules, including a recognition of the fact that states retain discretion in applying presumptive standards to any individual unit. *See, e.g.*, 88 *Fed. Reg*. at 33,276. Despite this, in proposing the retirement subcategories for existing coal-based EGUs, EPA does not appropriately recognize that states can alter the deadlines for particular units to retire, based on the states assessment of a range of relevant factors, including the remaining useful life of the unit. *See* 42 U.S.C. § 7411(d)(1). Accordingly, EPA must make clear that states can exercise their statutory discretion to alter the presumptive retirement

subcategories for existing units, provided such decisions are well supported in a state's implementation plan and result in appropriate emissions reductions. In addition to the express statutory authority to consider remaining useful life, states also can take into consideration other factors. These factors could include state-specific laws and regulations that could require units retire by certain dates that are later than those proposed by EPA.

In any final rule, therefore, EPA should affirmatively recognize that states have the ability to alter the applicability of the presumptively approvable subcategories to account for a range of factors, as required by the CAA. Moreover, EPA should make clear that it will evaluate any state proposals fully and not dismiss them for applying a standard other than the presumptively approvable subcategories proposed by the agency. This approach not only is grounded in the text of CAA section 111(d), but also will have environmental benefits as having units retire—even on a different schedule or with modified emissions limitations that apply in the period before retirement—results in *significant* emissions reductions in the aggregate. EPA should note that it is open to consideration of state plans that make modifications to the presumptively approvable subcategories, as long as those approaches are well-justified and track the ongoing fleet transition plans within those states.

4. EPA should align the subcategories in the proposal with the subcategories included in other rulemakings to help align decision making.

EPA has proposed retirement subcategories in other proposed rules for EGUs. Without explanation, and contrary to the Administrator's stated goal of a holistic approach to the suite of rules impacting the power sector, these retirement subcategories do not align. This significantly undercuts the benefits that could be achieved by these subcategories and frustrates owners'/operators' compliance planning. Accordingly, EPA should ensure that any final rule

adjusts the retirement deadlines so that they are consistent across rulemakings, as described below.

EPA's Proposed ELG Rule also includes a subcategory for coal-based units that will soon cease combustion of coal. *See* 88 *Fed. Reg.* at 18,824. Along with the subcategory in the Proposed ELG Rule, EPA issued a direct final rule—which went into effect May 30, 2023—extending the deadline to enter the subcategory for coal-based units that will soon cease combustion of coal that was part of the 2020 ELG Rule, codified at 40 C.F.R. § 423.19(f). *See* 88 *Fed. Reg.* at 18,440. While EPA has announced the goal of achieving a "holistic" approach to the various regulations for the power sector, the closure subcategories for the Proposed 111 Rule and the Proposed ELG rule do not align in several ways.

The subcategory in the Proposed ELG Rule is available to "early adopters," defined as those units that, as of March 24, 2023,[37] have installed technologies to comply with the requirements in the 2020 ELG Rule or the 2015 ELG Rule.[38] *See* 88 *Fed. Reg.* at 18,896 (to be codified at 40 C.F.R. § 423.11(x)). As proposed, "early adopters" entering this subcategory would not be required to install new technologies for flue gas desulfurization (FGD) wastewater and bottom ash transport water (BATW) prior to ceasing combustion of coal by December 31, 2032. "Ceasing combustion of coal" includes both plant retirement and repowering to a cleaner fuel source, such as natural gas. The deadline for submitting a Notice of Planned Participation

[37] The March 24, 2023, deadline corresponds to the publication of the Proposed ELG Rule in the *Federal Register*.

[38] *See* EPA, *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, 80 *Fed. Reg.* 67,838 (Nov. 3, 2015).

(NOPP) to enter this subcategory is one year after publication of the final rule. As a preliminary matter, the proposed ELG subcategories allow for repowering as well as retirement because once coal ceases to be combusted, the regulated waste streams, FGD wastewater and BATW, are no longer generated. However, as noted, the retirement subcategories in the Proposed 111 Rule do not appear to envision repowering. EPA should consider allowing for units in the imminent or near-term retirement subcategory to repower to become gas-steam units to better align with the requirements of the Proposed ELG Rule.

In addition, there is a misalignment with the subcategory timelines across both proposed rules. For example, as proposed, the "early adopter" subcategory in the Proposed ELG rule requires retirement by December 31, 2032. *See* 88 *Fed. Reg.* at 18,1896. However, the imminent-term retirement subcategory in the Proposed 111 Rules is December 31, 2031. *See* 88 *Fed. Reg.* at 33,361. EPA should align the Proposed ELG subcategory timelines and deadlines with the Proposed 111 Rules to the maximum extent practicable in order to allow for integrated and holistic decision making by EEI's member companies that are making retirement and investment decisions surrounding these units. EPA should finalize in both the Proposed ELG Rule and also the Proposed 111 Rules a deadline of December 31, 2032, for these subcategories. To the extent that EPA also considers creation of any additional subcategories in the Proposed ELG Rule beyond 2032, EPA should also ensure alignment of any new or extended ELG subcategory with the Proposed 111 Rule's near-term subcategory deadline, with a common deadline of December 31, 2035. Aligning these rules would support cost-effective and fully informed investment/retirement decision making, as well as provide EEI's member companies with significant certainty regarding avoiding investment in units that would otherwise retire.

5. The proposed near-term subcategory is inconsistent with the other retirement subcategories and should be designed to permit more flexible operation in the latter years of a unit's operating life.

The Agency also should consider changes to the proposed subcategory for near-term retiring units, which are those units slated to retire by December 31, 2034. As currently constituted, EPA's near-term subcategory unnecessarily and inconsistently limits operating flexibility for these units, resulting in more stringent standards for these units than for other coal-based units. EPA should consider a different presumptive standard for these units that accommodates a more gradual decrease in capacity factors for these units as they move toward retirement. EPA should also acknowledge that, consistent with EEI's other comments on these subcategories, that states can modify the parameters of these subcategories to address state-specific concerns.

EPA's proposed imposition of a strict capacity factor limitation of 20 percent beginning in 2030 and applicable until the date of unit retirement or December 31, 2034, under this subcategory is arbitrary and is central to the issues owners/operators have identified with respect to EPA's approach to these units. This appears to result in the application of an emissions limitation that is more stringent than EPA's requirements for medium-term retiring coal-based units, which are required to reduce their emissions rate by 16 percent, based on a BSER of co-firing with natural gas. *See* 88 *Fed. Reg.* at 33,377. While not explicit in the Proposed 111 Rules, it appears that EPA intended to ensure an increasing level of stringency in the standards that applied to existing coal-based units the longer that these units operate, with the most stringent standards applicable to those units that operate after 2040. The one exception to this pattern of increasing stringency is the capacity factor-based operating limitations proposed as the presumptive standard for those units that would retire no later than 2035. This capacity factor limitation for near-term retiring

units is an outlier. Further, a 20 percent-capacity factor restriction might be difficult to translate into a unit-specific emissions rate; or, at least, EPA has not provided any guidance on how states might make such a conversion.[39] EPA might accept a capacity factor restriction in lieu of an emissions rate limitation, although this is not clear from the Proposed 111 Rule. EPA should clarify this in any final rule if it retains a capacity-factor approach to units that retire no later than 2035.[40]

There are several options that the Agency could take that may offer additional flexibility and improved workability for this subcategory. EPA should consider adopting a "stair step" approach to establishing limitations for near-term retiring units, which would both allow units in the near-term subcategory to provide needed capacity in the early 2030s, while also better tracking the utilization of units that are slated to retire—e.g., units facing a retirement tend to operate less as they approach their final in-service date. To that end, the Agency could continue to utilize a capacity factor restriction approach and reduce the allowed capacity factor over the period from 2030 until 2035. For example: 40 percent in 2030, 35 percent in 2031, 30 percent in 2032, 25 percent in 2033, 20 percent in 2034, and retirement or refuel/retrofit/repower in 2035. The levels themselves could also be subject to state specific circumstances.

EPA could also consider that capacity factor restrictions, instead of beginning in 2030 as proposed, could begin after 2032, allowing units in this subcategory to utilize existing methods of operation and maintenance for the years immediately after 2030, as is proposed for the

[39] Neither has EPA explained how states could convert this into a unit-specific mass-based emissions cap, which would provide more operational flexibility.
[40] States might find this guidance useful for other units as well.

imminent-term subcategory. EPA could consider such a phased approach for increasing standard stringency across the entirety of its program as opposed to a beginning compliance in 2030 for all subcategories, which would track ongoing operational flexibility considerations.

This could provide operational flexibility to ensure that these units can continue to support reliability while also addressing the arbitrary increased stringency of the proposed presumptive standards for these units. EPA should consider adopting such an approach that would allow for these units to gradually operate less before retirement. At minimum, EPA should confirm in any final rule that states could choose to employ alternative approaches for particular units as part of exercising their RULOF authority, as discussed *supra*.

6. The Agency should authorize states to consider access to natural gas when establishing standards for medium-term units.

EPA also should consider changes to the presumptively approvable standards in the medium-term retiring unit subcategory in order to consider lower levels of natural gas cofiring based on state or regional specific circumstances. Not all regions of the country will have access to natural gas pipeline capacity to allow for co-firing up to 40 percent natural gas at units in this subcategory. Although not all units will be medium-term retiring units or actively will consider co-firing with natural gas as a control strategy, some regions might be more constrained than others, especially given existing pipeline capacity. Other states may, for reliability or other reasons, choose to have medium-term retiring units co-fire with more than 40 percent natural gas to address specific circumstances and situations, such as the existence of transmission constrained load pockets.

Given these concerns, EPA should allow states to adjust the requirements for medium-term retiring units to reflect regional and situationally specific circumstances. At minimum, EPA should note that it is open to consideration of state plans that make modifications to the medium-term retirement subcategory as a result of these scenarios.

C. EPA's Proposed Approach to Existing Natural Gas-Based Turbines is Not Supported by Sufficient Analysis; EPA Should Either Repropose These Guidelines or Significantly Supplement Them, Providing Additional and Comparable Compliance Flexibility as That Provided to Existing Coal-Based Generation.

EPA proposes existing source guidelines for states to regulate a subset of existing natural gas-based turbines, which are applicable to combined cycle units that have a nameplate capacity equal to or greater than 300 MW and operate at a capacity factor of greater than 50 percent. *See* 88 *Fed. Reg.* at 33,245. As noted, *supra*, EPA proposes a multi-phased BSER that tracks the requirements for new natural gas-based turbines, including the ability to opt into a hydrogen blending- or CCS-based compliance pathway that would become applicable in the 2030s. Notably, EPA does not propose any subcategories for affected existing natural gas-based turbines as part of the proposed guidelines.

EPA's inflexible, rate-based approach to regulating existing natural gas-based turbines presents significant challenges and is likely to result in perverse outcomes that are inconsistent with EPA's larger emissions reductions goals. EPA's failure to offer similar compliance flexibilities to existing natural gas-based turbines as those offered to states for existing coal-based units is fundamentally arbitrary. If EPA moves to finalize the proposed emissions guidelines for existing natural gas-based units, EPA must provide comparable compliance flexibilities for states to use when setting emissions limits for these turbines.

Existing natural gas-based units also are retiring as part of the industry's ongoing transition and provide many of the same reliability services that coal-based units do, including acting as a capacity resource and providing inertia and voltage support. In addition, many of these units also can provide fast ramping support that can be essential to the reliable integration of variable renewable resources. The same rationales that support the retirement categories that EPA proposes to allow states to use for existing coal-based units also support providing similar compliance flexibilities for these units. EPA should develop and provide the full range of flexibilities for existing natural gas-based units, including the development of retirement-based subcategories, the use of averaging and trading, mass-based compliance demonstration approaches, alternative fuel flexibilities, dual path options, and more (as discussed elsewhere in these comments), and these flexibilities should be tailored to the existing natural gas-based turbine fleet and its circumstances. Not to do so is arbitrary given that existing natural gas units are similarly situated to existing coal-based units in terms of how they operate and the role that they play in the reliability of the grid.

Further, the Agency's choice to have the proposal apply only to "larger" units that operate at capacity factors of 50 percent or greater could have significant unintended consequences for reliability, affordability, and emissions from the sector. The reliability requirements of the sector—handling increasing load due to electrification, providing reliable service in a resilient manner responding to storms, all while advancing clean energy deployment to meet the incentives provided by Congress—will continue to grow regardless of what resources are available to meet those needs.

Principally, EPA's approach—requiring units take either a capacity factor restriction or engage in a costly, capital intensive rebuild/retrofit to either blend with hydrogen or install CCS technology in the 2030s—has two potential likely outcomes: first, electric companies either will invest in costly retrofits or conversions to attempt to achieve EPA's proposed standards, deploying capital in a manner that requires long payback periods; or, second, the large and highly efficient units subject to the proposal will take a capacity factor restriction, effectively exempting themselves from EPA's requirements (on EPA's own terms) and limiting their usefulness in responding to larger grid reliability and resilience needs. Given expectations around increasing load as a result of increased electrification through the 2030s (which is already manifesting), once these large and efficient units near their capacity factor limits, electric companies will be forced to use other sources—including smaller, less efficient and older natural gas-based units, reciprocal internal combustion engine (RICE) units that operate primarily on diesel fuel, build additional renewables and storage, or extend the life of coal-based units that would have otherwise retired in the imminent or near-term category into either the medium or long-term based subcategory.[41] Under several plausible scenarios, this could result in an aggregate *increase* in emissions during the 2030s, at the expense of reliability. This is an outcome that should be avoided by the Agency.

Finally, EPA's entire existing natural gas-based turbine proposal needs significant additional analysis to support any final rule providing emissions guidelines for these units. The vast

[41] Earlier this summer in New England, dual fuel natural gas and oil-fired units were dispatched into the power market to ensure reliable system operations to address capacity shortfalls after a transmission line issue—indicative of what units are called on when capacity requirements must be met. *See* https://isonewswire.com/2023/07/06/iso-ne-successfully-manages-through-july-5-capacity-deficiency/.

majority of EPA's analysis to identify units to which to apply the existing source guidelines appears to be a single chart focusing on a subset of identified units that have historically been dispatched at capacity factors of 50 percent or greater. *See* 88 *Fed. Reg.* at 33,363. Since then, EPA has released additional modeling and docket materials to try and buttress this approach given its limited nature. EPA then selects a BSER identical to the new source requirements, mostly upon an assertion that existing and new sources are "similar," and then states that these units are not able to access the same type of flexibilities that are offered coal-based existing units. *Id*. This adequate demonstration analysis and EPA's approach to applicability for existing natural gas-based turbines are arbitrary and insufficient. One of the most glaring omissions is EPA's complete failure to grapple with the significant role that existing natural gas-based generation plays in overall system reliability and the challenges associated with retrofitting existing natural gas-based units.

As the fleet continues to transition, natural gas-based turbines will continue to play a critical and evolving role in integrating increasing amounts of renewable generation and providing essential reliability services to allow for the ongoing retirement of the coal-based generation fleet while preserving customer affordability. Natural gas-based turbines are significantly more flexible than coal-based units given their ability to ramp quickly, especially as compared to other dispatchable units, including nuclear units and coal-based EGUs—e.g., they are able to come online quickly and provide power to the grid much faster while also being able to ramp down as needed. This fast-ramping ability both minimizes emissions related to start up and shut down and also helps to avoid emissions by supporting the integration of variable renewable generating resources.

Some units may operate at significant capacity factors—greater than 80 percent—for long periods of time to respond to system considerations, resulting in highly efficient generation from an emissions rate perspective.[42] Other units might instead respond to intermittent system needs, operating at capacity factors of less than 15 percent while still providing essential reliability services and helping to reduce overall system emissions. Further complicating matters, units that operate at high or low (or even in between) capacity factors for long stretches are not guaranteed to remain in that mode while demand for their energy and other services changes continuously in response to system needs. Units are obligated to respond when called upon based on these system needs, which will change further in coming years as the generation mix of the grid continues to evolve.

One consequence is that these units likely will be required operate differently.[43] These changes will have a significant impact on the emissions and emissions rates associated with these units. This includes the potential for: units switching between operational modes (e.g., simple v. combined cycle) to respond to voltage demands; units in specific locations running more or less often to respond to generation intermittency, transmission congestion or new transmission coming online changing the dynamics of the operating grid; and the aging of the existing gas fleet, which will continue as the fleet transition continues. Each of these scenarios will result in a significant impact on the efficiency rates and the CO_2 profile of existing gas-based units and the

[42] In general, the emissions rate of an individual unit is more efficient (resultingly, lower) when it run at higher capacity factors. Units that operate at lower capacity factors have concomitantly higher, less efficient emissions rates despite having fewer mass emissions of CO_2.

[43] *See, e.g.*, Eric Larson, et al., *Net-Zero America: Potential Pathways, Infrastructure, and Impacts*, Final report (Princeton University, Oct. 2021), https://netzeroamerica.princeton.edu/the-report.

associated efficiency rates for those units. Consequently, the sheer diversity of the types of units and the range of possible operating characteristics of the existing turbine fleet makes determining an implementable BSER for these units extremely difficult, as EEI noted to the Agency in April 2023 comments to the non-regulatory docket that are attached as Appendix C. EPA addresses none of these salient issues in its analysis of the feasibility of the proposed standards, which would be effective far into the future.

Taken together—the lack of compliance flexibility, the potential unintended emissions consequences of EPA's approach, and the Agency's insufficient analysis regarding the changes and variability in how these units operate—are significant flaws with the proposed emissions guidelines for existing natural gas-based units. They likely render the Proposed 111 Rules arbitrary, capricious, and unsupported on the record for existing gas-based units.

The Agency, therefore, should repropose or significantly supplement its existing source emissions guidelines for existing natural gas-based turbines to address these concerns. In the context of the analysis that will be necessary to support any re-proposal or supplemental rulemaking, EPA should focus on crafting an approach that includes subcategories that reflect the vast array of types and categories of units, including those that reflect more nuances with respect to operational modes; the ability to convert rate-based standards into mass-based compliance options; multiple different averaging forms; and the ability of states to leverage existing programs, among many other approaches. EPA should adopt options that could allow units to choose among multiple paths to comply with EPA's BSER, helping to facilitate diverse unit owner/operator approaches that also consider customer affordability and grid reliability. If EPA

opts not to repropose the emissions guidelines for existing natural gas-based EGUs, the Agency must provide comparable compliance flexibility, including retirement-based subcategories tailored to the circumstances of the natural gas turbine fleet, to these units as that provided to existing coal-based units.

D. There are Significant Procedural Considerations EPA Must Account for when Finalizing These Rules.

Agencies are not bound to finalize rules exactly as they were proposed. However, final rules must be a "logical outgrowth" of the proposal. *See, e.g., Nat'l Mining Ass'n v. Mine Safety & Health Admin.*, 512 F.3d 696, 699 (D.C. Cir. 2008). "The key question is whether commenters 'should have anticipated'" that the agency might take the course of action it ultimately chose. *City of Waukesha v. EPA*, 320 F.3d 228, 245 (D.C. Cir. 2003) (citation omitted). Under this standard, "incremental changes are permissible." *Sierra Club v. Costle*, 657 F.2d 298, 352 (D.C. Cir. 1981).

Final standards or guidelines should be an expectable result of the rulemaking process based on the proposal and the feedback received to avoid subjecting EPA to additional scrutiny. "One logical outgrowth of a proposal is surely … to refrain from taking the proposed step." *New York v. EPA*, 413 F.3d 3, 44 (D.C. Cir. 2005) (citation omitted); *Ariz. Pub. Serv. Co. v. EPA*, 211 F.3d 1280, 1299–1300 (D.C. Cir. 2000). However, what is *not* permissible is finalizing a rule that, instead of declining to adopt a rule as proposed, adopts a wholly *new* interpretation of the statute without additional notice and opportunity for comment. *Envt'l Integrity Proj. v. EPA*, 425 F.3d 992, 997 (D.C. Cir. 2005); *id.* at 998 ("Whatever a 'logical outgrowth' of [an agency's] proposal may include, it certainly does not include the Agency's decision to repudiate its proposed [position] and adopt its inverse."). For such changes to be lawful, EPA must first have "alerted

interested parties to the possibility of the agency's adopting a rule different than the one proposed." *Kooritzky v. Reich*, 17 F.3d 1509, 1513 (D.C. Cir. 1994).

EPA faces a particular challenge with rulemaking under section 111—because EPA's rule will apply to all new facilities constructed following the date of *proposal*, the reliance interests engendered by the proposal are heightened. *Cf. Smiley v. Citibank (S.D.), N.A.*, 517 U.S. 735, 742 (1996) (a change in position "that does not take account of legitimate reliance on" the prior position may be arbitrary and capricious); *MediNatura, Inc. v. Food & Drug Admin.*, 998 F.3d 931, 940 (D.C. Cir. 2021) (reiterating need to evaluate reliance interests "[w]hen an agency changes policy" (cleaned up)). So too, therefore, are the consequences of failing to provide notice and an opportunity to comment on any unanticipated changes in the final rule. Section 111(b) rules, in this way, are fundamentally unlike the typical rule, which is finalized and only sometime thereafter becomes effective. Under section 111(b), regulated entities have to begin preparing *immediately* to comply with whatever rule EPA decides to make final. This fact must result in a narrowing of the range of potentially logical outgrowths of the proposal, with a corresponding widening of situations in which a new proposal or revision with an additional comment period becomes necessary.

This is especially pertinent for EPA's rulemakings here; should EPA significantly overhaul and accelerate its timelines—or provide the additional flexibilities for existing natural gas units these comments recommend—the Agency likely will need to address logical outgrowth issues. As a result, as the Agency moves forward, it should take care not to completely overhaul its proposals

without providing stakeholders the opportunity to comment specifically on the range of approaches EPA is considering.

Ultimately, to help continue the successful and ongoing clean energy transition of the power sector, EPA must design standards for both new and existing units that achieve emissions reductions goals, are consistent with electric company clean energy commitments, and support affordable and reliable electricity. Commenters must have the ability to provide substantive feedback on EPA's specific proposals to ensure that they are achievable and not inconsistent with the rest of EPA's rulemaking agenda for the sector. Providing additional opportunities for comment and feedback will only assist the Agency in this task—and it is EPA's obligation to do so as well.

The time afforded for comment on the Proposed 111 Rules was comparatively short. EEI will continue to consider options to improve the Proposed Rules, particularly those for natural gas-based generation, even after these comments are filed and will share any developments with EPA and other stakeholders. In addition, the Federal Energy Regulatory Commission has announced that the 2023 Annual Reliability Technical Conference will address policy issues related to the reliability and security of the bulk power system, as well as the Proposed 111 Rules. EPA should consider the outcomes of these efforts as it works to finalize standards for new and existing fossil-based generation.

III. EPA Has Not Shown That Either CCS Or Hydrogen Blending Are Adequately Demonstrated And That The Proposed Standards Are Achievable Across All Regulated Units.

EPA has failed to show that either CCS or the hydrogen blending requirements are adequately demonstrated and can be BSER. As a result, the proposed standards based on the application of these BSERs may not be achievable across all regulated units.

While EPA asserts that individual constituent elements of each technology are adequately demonstrated, EPA does not address that these disparate pieces must function as a whole if the standards are to be achievable. EPA's statutory obligations are clear: to select as BSER a technology that is adequately demonstrated and then set emissions limits are achievable across the entire sector (or provide guidelines for the statues to set achievable emissions limits). By not ensuring that the component pieces of each technology are demonstrated as one, integrated whole, EPA falls short of its statutory obligations and the Agency's expansive reading of CAA section 111 and the related caselaw do not overcome this failure.

A. EPA's Determination That CCS and Hydrogen Blending Are Adequately Demonstrated is Legally Insufficient.

For the purposes of section 111, a "standard of performance" is currently defined as:

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the *best system of emission reduction* which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines *has been adequately demonstrated*.

See 42 U.S.C. § 7411(a)(1) (emphasis added). In promulgating CAA section 111(b) standards for new and modified sources, EPA has typically used a straightforward process to: (a) identify what emission reduction technology/systems exist for a source category; (b) assess related costs and secondary air benefits (or disbenefits) from associated energy requirements; and (c) examine any

non-air quality impacts of employing those technologies or systems.[44] Following this analysis, EPA promulgates a standard of performance, usually in the form of a numeric emission limit based on installation and operation of the identified technologies or systems—that is, the "best system of emission reduction," or BSER.

Section 111(d) provides that EPA must establish procedures under which each State must submit a plan that establishes standards of performance for any existing source within its borders for any pollutant "to which a standard of performance … would apply if such existing source were a new source."[45] The statute further provides that regulations promulgated under section 111(d) shall allow States in "applying a standard of performance to any particular source [under a state plan submitted to EPA] to take into consideration, *among other factors*, the remaining useful life of the existing source to which such standard applies."[46]

Although in the first instance section 111(d) authorizes the individual states, and not EPA, to set standards of performance for and to apply those standards to existing sources, EPA promulgated section 111(d) implementing regulations in 1975 that require the Agency to both identify the BSER *and* develop "guidelines" reflecting emission reductions that can be achieved by existing

[44] *See, e.g.,* Env't Prot. Agency, Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act, https://archive.epa.gov/epa/sites/production/files/2013-09/documents/111background.pdf.

[45] 42 U.S.C. § 7411(d)(1). Section 111(d) authority is, as an initial matter, contingent on the existence of a corresponding 111(b) rule (*i.e.*, it exists only where a "standard of performance under this section would apply if such existing source were a new source").

[46] 42 U.S.C. § 7411(d)(1) (emphasis added). If a State fails to submit a satisfactory plan, EPA must develop and implement a federal plan for that state that meets the requirements of the section. *Id.* at § 7411(d)(2).

sources through the application of the selected BSER. *See* 40 C.F.R. sections 60.22(b)(2) and (b)(5). EPA's guidelines must provide information for the development of state plans that:

- Reflect application of the BSER (considering the cost of such reduction) that has been *adequately demonstrated*;
- Address "the *time* within which compliance with emissions standards of equivalent stringency can be achieved"; and
- Specify "different emission guidelines or compliance times or both for different sizes, types, and *classes* of designated facilities when *costs of control, physical limitations, geographic location, or similar factors* make subcategorization appropriate."

Id. (emphasis added). EPA's section 111(d) implementing regulations further provide that, where a designated pollutant has been determined to endanger public health, standards of performance developed as part of a state implementation plan must be at least as stringent as those established by EPA's section 111(d) guidelines and compliance achieved "as expeditiously as practicable." *See* 40 C.F.R. section 60.24(c). Thus, how EPA defines BSER in its guidelines, in general, drives the minimum stringency of state standards of performance for existing sources. At the same time, however, states have considerable flexibility in applying BSER to affected sources on a case-by-case basis.

Per the express language of section 111(b)(1)(B), a standard of performance "become[s] effective upon promulgation," and under section 111(a)(2) is applicable to any "new source"—defined as any source "the construction or modification of which is commenced after the publication of [an applicable NSPS] (or, if earlier, proposed regulations)." 42 U.S.C. § 7411(b)(1)(B), (a)(2). For new sources, two things are apparent from this: first, any New Source Performance Standard (NSPS) is effective immediately upon finalization; second, to ensure that sources do not rush commencement of construction during the pre-finalization notice-and-comment period, all

sources that are built after the NSPS's proposal date are covered. Because of this, the statute expressly requires that Administrator determine that the BSER upon which the standards are based "has been adequately demonstrated"—in the *past* tense—and not that EPA projects that it might at some *future* date be adequately demonstrated.

EPA must therefore select a "best system of emission reduction" that is *presently* adequately demonstrated, and it must set a standard of performance that is achievable—these are two separate requirements. *See* 42 U.S.C. § 111(a)(1). As the D.C. Circuit has explained, "it is the system which must be adequately demonstrated and the standard which must be achievable." *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973); *see also Nat'l Asphalt Pavement Ass'n* v. *Train,* 539 F.2d 775, 785 (D.C. Circ. 1976) (quoting same). With regard to whether the technology underlying an NSPS "has been adequately demonstrated," the D.C. Circuit has opined that "section 111 most reasonably seems to require that EPA identify the emission levels that are 'achievable' with 'adequately demonstrated technology' … which represents the best balance of economic, environmental, and energy considerations." *Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981). Moreover, "[s]ince the standards here put into effect [that is, under section 111(b)] will control new plants *immediately*, as opposed to one or two years in the future, *the latitude of projection is correspondingly narrowed*." *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 392 (D.C. Cir. 1973) (emphasis added).

For both new and existing sources, an adequately demonstrated system is "one which has been *shown* to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or

environmental way." *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973) (emphases added). EPA is not limited to what may currently be the "state of the art" in a sector but may instead "look[] toward what may fairly be projected for the regulated future." *Portland Cement*, 486 F.2d at at 392. EPA may also rely on projections that a technology will become available, but it is not permitted to engage in a "crystal ball inquiry." *Portland Cement*, 486 F.2d at 391-92 (citing *Int'l Harvester v. Ruckelshaus*, 478 F.2d 615, 629 (D.C. Cir. 1973)). *See also Essex Chem. Corp.*, 486 F.2d at 433 ("An achievable standard is one which is within the realm of the adequately demonstrated system's efficiency and which, while not at a level that is purely theoretical or experimental, need not necessarily be routinely achieved within the industry prior to its adoption."). As with adequate demonstration, EPA's determination of a standard's achievability cannot rest on "mere speculation or conjecture." *Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999) (per curiam).

Further, for both new and existing sources EPA also is required under CAA section 111 to show that standards must be achievable by sources across a wide range of operating conditions. "A uniform standard must be capable of being met under most adverse conditions which can reasonably be expected to recur and which are not or cannot be taken into account in determining the 'costs' of compliance." *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431-33, n.46 (D.C. Cir. 1980).

EPA has fallen short of these requirements in the Proposed 111 Rules.

1. **EPA's CCS and hydrogen blending adequate demonstration analysis does not address the necessary integration of the constituent elements of these technologies now.**

EPA has not legally supported its conclusion that CCS or hydrogen blending are BSER. The record lacks substantial evidence showing that these technologies are currently demonstrated at scale, or could be demonstrated at scale in a commercial setting.[47] Most critically, while EPA cites individual components of both CCS and hydrogen blending—e.g., a functioning capture amine system, the existence of a CO_2 pipeline, hydrogen blending pilots—it *never* shows in its record that these components are integrated at scale across the industry and are available for sources to use to meet the resulting emissions limitations.

The statute expressly requires that EPA identify a BSER that "has been adequately demonstrated." By its very terms, that phrase connotes something that is available *now* for existing units to employ because it has *already been demonstrated*. That is not the case for CCS or hydrogen blending. EPA enjoys a certain amount of latitude in its predictive judgments, "[o]ne must distinguish between prediction and prophecy." *Int'l Harvester*, 478 F.2d at 642 (citation omitted). But when predicting future conditions, the Agency must provide "a reasoned presentation of the reliability of [the] prediction and the methodology that is relied upon …." *Id.* at 648. Neither may EPA rely on prototypes, nor leave unanswered critical questions about the practical aspects of a system such as waste disposal. *See Costle*, 657 F.2d at 341, n. 157, *Essex Chem.*, 486 F.2d at 435, n.19, 438.

EPA recognizes that any standard relying on "improved design and operational advances" must be grounded in "substantial evidence that such improvements are feasible," but misses the mark

[47] *See* Appendix A, Chapter 2 – New Technologies Will be Essential to Achieving the Clean Energy Transformation, and EPA's Regulatory Structure Can Help Advance Those Technologies.

with its determination that CCS and hydrogen blending are BSER. No "substantial evidence" regarding the present feasibility of CCS or hydrogen blending as BSER for a nationwide standard exists in the record. *See* 88 *Fed. Reg.* at 33,272. As discussed later in this section, there are real, practical constraints on the ability of CCS to be widely available in the timeframe posited—much less "immediately," as required by the *Portland Cement* decision—and with sufficient ability to achieve the proposed standards of performance. *See Portland Cement*, 486 F.2d at 391-92. This is critically also problematic, as discussed *infra* in this section as well, for EPA's determination that hydrogen blending is likewise feasible and available across the industry today. These include insufficient pipeline infrastructure and the absence of any federal regime for pipeline permitting or eminent domain authority for those pipelines. For CCS, permitting of the other elements of infrastructure and storage, not to mention concerns regarding long-term liabilities associated with storage, must also be resolved before this technology can be said to be adequately demonstrated for and available to the power industry nationwide. For hydrogen blending, these projects are at most at pilot stage and have not been utilized at load, at scale, or cross different grid scenarios, not to mention the lack of hydrogen related infrastructure to produce, transport and utilize hydrogen in the power sector.

EPA has not shown how those issues can be overcome by the time this Rule is finalized, and it is therefore impossible to see how EPA can lawfully conclude that either CCS or hydrogen blending are adequately demonstrated now. As of now and with the record in this proposal, EPA cannot claim with any measure of certainty that CCS or hydrogen blending is or "has been adequately demonstrated" or that it will be available at a date certain in the near future.

Moreover, EPA acknowledges that a standard is only achievable if the technology to be used "can reasonably be projected to be available to an individual source *at the time it is constructed* that will allow it to meet the standard." *See* 88 *Fed. Reg.* 33,275, citing *Sierra Club v. Costle*, 657 F.2d at 364 n.276 (emphasis added). That is *not* what EPA has proposed. EPA expressly recognizes that "building the infrastructure required to support widespread use of CCS and low-GHG hydrogen in the power sector will take place on a multi-year time scale." 88 *Fed. Reg.* at 33,283. EPA provides no assurance (and cannot provide assurance) that such infrastructure will in fact be in place by 2038, much less by 2032. Given the lack of that infrastructure, EPA cannot determine that either technology is adequately demonstrated, since on its own terms EPA cannot prove that the individual components of each technology can work together across the industry and be available—as EPA itself acknowledges.

EPA attempts to address concerns about adequate demonstration by conceding that these technologies are not yet widely available and thus will not be truly adequately demonstrated until some date in the future but contends that CCS actually *is* adequately demonstrated now on a *unit* basis. However, EPA lacks substantial evidence to support this lesser conclusion. For existing sources, EPA's proposal to include retrofitting CCS for existing coal- and natural gas-based facilities misses the mark. Retrofitting is prohibitively difficult, given the likely space constraints and other associated technical challenges. And EPA is not even certain there will be sufficient geologic space to sequester the carbon. The Agency, for example, expressly acknowledges the complications of permitting geologic sequestration on federal land. *See* 88 *Fed. Reg.* at 33,297. EPA implies there are numerous extant examples of CCS currently in operation, but in truth can point to only one facility, in Canada, that is approaching the levels of CCS capture that EPA

would require in this proposal. *See id*. at 33,368. As discussed *infra*, this is not enough to show that CCS is adequately demonstrated for deployment on a nationwide scale, without regard to location, geology, and other constraints on plant design. For hydrogen blending, EPA attempts to note that numerous pilot studies and federal efforts to establish infrastructure is proof positive of achievability on a unit basis. As discussed in these comments, EPA has not grappled with an array of issues regarding these assertions.

Aside from the substantive concerns underlying EPA's lack of record-based support for its adequate demonstration determination, there are both a procedural and a structural issue that are central to why EPA must show that the BSER it selects is achievable and demonstrated not just in component pieces but as an integrated whole: What happens if EPA's projections are wrong? Any challenge to EPA's final rule brought at the time that it is clear that EPA's projections were not correct—that is, in 2030, 2032, 2035, or 2038 when compliance obligations are incumbent on states and units—will be years too late under the CAA's judicial review provision, which requires that challenges to regulations be brought within 60 days of their finalization. *See* 42 U.S.C. § 7607(b). The Act's structure—both the substantive provisions of section 111, which require immediate application of an NSPS, and the procedural provisions of section 307, which require immediate judicial review—leads to the conclusion that EPA must demonstrate that its chosen BSER is adequately demonstrated and available to the regulated industry *now*.

Another issue with EPA's reasoning is the Agency's lack of acknowledgment that, in promulgating a phased BSER with multiple compliance "pathways," those pathways—however distinct—must operate as an integrated whole, *i.e.*, a "system" of emission regulation. Thus, EPA

must determine that it has been adequately demonstrated that, no matter which pathway a new unit chooses, those units will be able to work together throughout their respective electrical grids. Similarly, any BSER discussion that does not address whether all elements of EPA's chosen technology system can be integrated at commercial scale by sources across the country is inherently lacking. This is particularly important in this source category, because it is the *only* source category with a public service obligation to operate, and because the entities making up that category face penalties for failing to provide reliable electricity to their customers. The full operability of *all* elements of a technology system is vital for EGUs, given the power sector's unique obligation to be available and on call to provide power whenever it is needed. As a result, for example, a demonstration of the integration of hydrogen, including all system elements, with EGUs is critical in order to make a finding on adequate demonstration: the nation's electricity customers must be assured not only that the technology works, but also that it allows generators to meet their capacity and reliability obligations at the same time.

While EPA recognizes in the abstract that it "may assess whether controls it is considering would create risks to the reliability of the electricity system in a particular area or nationwide," 88 *Fed. Reg.* at 33,274, EPA has ignored the very real possibility of this concern materializing in this very rule, rendering the BSER determination inadequate.

Given these very real concerns, EPA's ultimate determination that CCS and hydrogen blending constitute BSER is insufficient legally.

2. EPA does not have the authority under CAA section 111 to develop "phased" future standards for either new or existing units based on projections of technology development.

For natural gas-based units, EPA proposes that BSER for new stationary combustion turbines, depending upon the pathway chosen, is 90 percent CCS *by 2035* or 96 percent low-GHG hydrogen blending *by 2038*, coupled with an interim milestone of 30 percent low-GHG hydrogen blending *by 2032*. For existing natural gas-based combustion turbines, EPA has likewise proposed CCS or low-GHG hydrogen as the BSER, while BSER for existing coal-based steam generating plants will be a combination of routine operation and maintenance/no increase in emission rate, natural gas use, and CCS.

As a general matter, EPA's approach to the near-term requirements—"phase one" for new units, and routine operation and maintenance/emission rate stasis for existing units—appears to meet the requirements of the statute despite some technical questions regarding EPA's determinations about the ability to comply with the rate chosen by the Agency, which are addressed in these comments *infra*.[48] EPA's proposed requirements for CCS and low-GHG hydrogen in subsequent phases, however, are not legally supportable. For low-GHG hydrogen blending, EPA is not actually suggesting that this technology is adequately demonstrated *now*; rather, EPA merely *projects* that it will be adequately demonstrated in and through the 2030s. Similarly, for CCS, while EPA contends that the technology is adequately demonstrated now on a *unit* basis, the Agency concedes that CCS is not yet able to be implemented nationwide due to geologic, infrastructure, and other present constraints.

[48] To be clear, EEI's concerns—detailed *infra*—have to do with the proposed emission rate, not the use of an efficiency-based standard.

Concluding now that these technologies are BSER is therefore an unsustainably expansive reading of EPA's authority under the statute. As noted above, section 111 requires that standards of performance be "achievable" through a BSER that "*has been* adequately demonstrated."[49] This makes sense, because by section 111's express terms, all new sources the construction or modification of which commences after the date a new NSPS is *proposed* must incorporate or meet the level of emission reductions achieved by that new system of emission reduction. As the D.C. Circuit noted in *Portland Cement*, an NSPS is effectively *immediately*, and EPA's ability to project the availability of technologies at some future date is correspondingly narrowly cabined. *Portland Cement*, 486 F.2d at 391-92. EPA's approach does not accord with the text of the statute, which requires EPA to base BSER on a technology that "*has been* adequately demonstrated"—not one that "will be" (or, more accurately here, might be) demonstrated by some "future date certain."[50]

a. EPA's assertion that "lead time" allows for the development of phased standards is mistaken.

Instead of locating support in the statute, EPA relies inappropriately on just one decades-old case stating that the courts will evaluate EPA's conclusions regarding availability of a technology in conjunction with the "lead time" afforded before the technology is required to be deployed. *See* 88 *Fed. Reg.* at 33,289, citing *Portland Cement*, 486 F.2d at 391. Put simply, it is one thing for a technology to be adequately demonstrated today but to require some "lead time" for implementation; it is another for EPA to project a date some years in the future when an

[49] 42 U.S.C. § 7411(a)(1).

[50] *Compare* 42 U.S.C. § 7411(a)(1) (using past tense to refer to a BSER that "has been adequately demonstrated"), *with* 88 *Fed. Reg*. at 33,273 ("EPA may determine a 'system of emission reduction' to be 'adequately demonstrated' if the EPA reasonably projects that it will be available by a future date certain").

emerging technology might be adequately demonstrated and available for use. The former *might* pass muster under the Act; the latter does not. *See Am. Fuel & Petrochem. Mfrs. v. EPA*, 3 F.4th 373, 383 (D.C. Cir. 2021) (allowing specific statutory percentage to be read to include a margin for compliance but not an entirely different percentage altogether).

NSPS are to be "effective upon promulgation," and a "new source" to which the NSPS is applicable is one "the construction or modification of which is commenced after the publication of regulations (*or, if earlier, proposed regulations*)." *See* 42 U.S.C. §§ 7411(b)(1)(B) and 7411(a)(2) (emphasis added). A system of emission reduction that does not yet exist—that is, one that is not yet adequately demonstrated—cannot be made "effective upon promulgation" and cannot be implemented by a source constructed immediately after the date of the NSPS's proposal.

Likewise, setting a BSER that is not predicted to be adequately demonstrated until more than a decade in the future undermines Congress' requirement that EPA consider NSPS revisions on an eight-year cycle. *See* 42 U.S.C. § 7411(b)(1)(B). Congress anticipated that technologies would develop sufficiently quickly that what might be state-of-the-art one year may be overtaken by superior technologies in relatively short order—and determined that EPA should regularly consider and, if appropriate, require sources built after that statutorily-required reexamination to implement those new technologies. EPA's determination in the proposed rule that critical elements of its BSER are not presently adequately demonstrated—thus proposing to delay their implementation until some future time a decade or more away, but nonetheless applying the rule

to all sources built after the date on which this proposed NSPS is published in the Federal Register—runs contrary to Congress's carefully-constructed statutory framework.

Further, EPA has identified no limiting principle to its "lead time" construct. Taken to its logical conclusion, EPA's interpretation as allowing the Agency to predict the availability of future technologies and apply them to sources built *now* would mean that the Agency could promulgate an NSPS with a BSER that isn't projected to be available for decades, as long as the Agency promises not to enforce the requirement until a "future date certain."[51] Critically, Congress did not provide EPA with such authority.

EPA relies on *Portland Cement* to support its assertion of authority to require a phased BSER spread over more than a decade. *See* 88 *Fed. Reg.* at 33,275. Such reliance is misplaced. As an initial matter, there, unlike here, the court was not presented with a phased NSPS.[52] True, the court in that case described "lead time" as "the time in which the technology will have to be available." *See Portland Cement*, 486 F.2d at 391. Crucially, though, that is not all the court said. In the immediately preceding sentence, the court stated explicitly that any projections about the

[51] *See, e.g.*, 88 *Fed. Reg.* at 33,275, among many (reflecting an essentially limitless ability to project requirements applicable "at a future time"). Query, though, what happens if the technology does not develop as EPA predicts. Sources built after the date of the NSPS's proposal would still be required to meet the BSER at that future time, even though it would be impossible for them to do so. And the time for challenging the rule—limited to 60 days from its finalization—would long since have run.

[52] For the Portland Cement plants at issue in *Portland Cement*, there was no substantive dispute about the availability of the PM control technologies at issue; they had been deployed and used by a notable subset of the industry. The dispute was regarding costs and level of the standard, knowing that the technology itself was in fact available and demonstrated as a technical matter across operating conditions. That is a markedly different scenario than is presented here, and one that does not inure to EPA's benefit.

future availability or performance of a system of emission reduction for the source category are "subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry" or "mere speculation or conjecture." *Id*. The court also explained that in the context of section 111(b), where "the standards … will control new plants *immediately*, as opposed to one or two years in the future, the latitude of projection is correspondingly narrowed." *Id*. at 391-92 (emphasis added). EPA simply ignores this express judicial caveat in its proposal.[53]

b. EPA has no other regulatory precedents for proposing phased standards.

EPA offers no regulatory precedent for promulgating a BSER that is reliant on a technology that is not available now but that the Agency projects will be adequately demonstrated sometime in the future. The examples upon which EPA relies do not support EPA's current proposals. Rather, those rules merely demonstrate that the Agency may accommodate logistical and other impediments to deployment of an already existing technology.[54] In cases such as this, where an

[53] Moreover, EPA ignores that *Portland Cement*'s discussion of lead time hearkened back to *International Harvester Co. v. Ruckelshaus*, a case involving the *mobile source* provisions of the Act.[53] In those provisions, the concept of "lead time" not only makes eminent sense given the implementation timeframes required to design and roll out millions of new motor vehicles, but also (and in stark contrast to section 111) finds support directly in the statute itself. Instead of being "effective upon promulgation" and applicable to sources built after the date an NSPS is proposed, mobile source standards "shall take effect *after* such period as the Administrator finds necessary to permit the development and application of the requisite technology." Indeed, in the case of mobile source-related air toxics, EPA is to promulgate requirements reflecting "the greatest degree of emission reduction achievable through the application of technology which *will be available*…." Congress understands verb tense, understands the concept of lead time, and knows when and how to allow EPA to plan for future availability of a technology. While it plainly did so for mobile sources, Congress very clearly chose *not* to do that for stationary sources in the statute's NSPS provision.

[54] *See, e.g.*, 81 *Fed. Reg.* 59,332 (Aug. 29, 2016) (establishing NSPS for municipal solid waste landfills with 30-month compliance timeframe for installation of control device, with interim milestones); 80 *Fed. Reg.* 13,672 (Mar. 16, 2015) (establishing wood heaters NSPS with stepped compliance approach to permit manufacturers lead time to develop, test, field evaluate and certify current technologies to meet Step 2 emission limits that were already being met by

agency uncovers new authority where none was thought to exist previously, courts may at minimum apply additional scrutiny to this new claim. *See Utility Air Regul. Grp. V. EPA*, 573 U.S. 302, 324 (2014).

Congress provided for review and, as appropriate, revision of each NSPS every eight years. It stands to reason, then, that what is reasonable "lead time"—even for implementation, not technology development—cannot extend beyond the next round of NSPS review, at which time a once-new source ceases to be a statutory "new source."[55] As the D.C. Circuit recognized in *Sierra Club v. Costle*, "[a]lthough it is conceivable that a particular control technique could be considered both an emerging technology and an adequately demonstrated technology, there is inherent tension between the two concepts…." *Costle*, 657 F.2d at 341, n.157. Instead of grappling with and attempting to reconcile this tension, EPA does not address it.

c. EPA has no statutory basis for a phased approach.

An additional and important constraint on EPA's legal authority concerns *when* section 111 requires compliance. As noted, section 111(b)(1)(A) specifies that an NSPS "shall become effective *upon promulgation*," and section 111(a)(2) specifies that it applies to any source constructed after the NSPS is *proposed*. *See* 42 U.S.C. §§ 7411(b)(1)(A) and 7411(a)(2), respectively. The D.C. Circuit has stated that NSPS "control new plants immediately" and

existing sources); 78 *Fed. Reg.* 58,416 (Sept. 23, 2013) (revising oil and gas NSPS to establish phase-in period to permit sufficient time for production of necessary supply of control devices and for trained personnel to perform installation).

[55] As the statute makes clear, for purposes of section 111, a "new source" is one "the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section *which will be applicable to such source*." 42 U.S.C. § 7411(a)(2). Stated another way, once EPA conducts its eight-year review and promulgates a new NSPS for a source category, a "new source" is one to which that new NSPS applies.

therefore that EPA's discretion to project the future availability of technology is "correspondingly narrowed." *Portland Cement*, 486 F.2d at 391-92. Section 111(b) also provides that "[*a*]*fter the effective date of standards* of performance promulgated under this section, it shall be unlawful for any owner or operator of any new source *to operate such source in violation of any standard of performance applicable to such source*." These three provisions, when read together, mean that all requirements contained in an NSPS must apply to all affected sources as of the date of promulgation, at the very latest. This in turn means that the BSER must be adequately demonstrated at the time the rule is proposed.

While EPA claims that phase two standards will be "effective upon promulgation," that is plainly not the case. EPA adopts a strained reading of the statute under which phase two standards are "effective upon promulgation" simply by virtue of the fact that it *appears in* the NSPS, even though no source will be held to it (or indeed could be held to it) for many years to come. *See* 88 *Fed. Reg.* at 33,289. EPA appears to read the term "effective" as allowing an NSPS to apply in a partial fashion both initially and in the future—as the Agency states, "upon promulgation, affected sources become subject to a standard of performance that limits their emissions immediately, … and they *also* become subject to more stringent standards beginning in 2032 or later." *Id.* (emphasis added). The Agency, however, cites nothing in the statute that allows this broad and counterintuitive reading of section 111, nor any case law supporting such a reading. If the Agency believes more stringent standards will be justifiable in the future, it may promulgate a new NSPS *at that time*.

Indeed, this appears to get to the heart of why EPA advances such a strained reading of the statute. As EPA admits, applying the statute according to its plain terms would cede its ability to proactively regulate later-built sources pursuant to the more stringent low-GHG hydrogen and enhanced CCS technology requirements:

> It should be noted that the multi-phased implementation of the standards of performance that the EPA is proposing in this rule … is distinct from the promulgation of revised standards of performance under the 8-year review provision of CAA section 111(b)(1)(B)…[T]he EPA has determined that the proposed BSER—highly efficient generation and use of CCS or highly efficient generation and co-firing low-GHG hydrogen—meet all of the statutory criteria and are adequately demonstrated for the compliance timeframes being proposed. Thus, the second and third phases of the standard of performance, if finalized, would apply to affected facilities that commence construction after the date of this proposal. *In contrast, when the EPA later reviews and (if appropriate) revises a standard of performance under the 8-year review provision, then affected sources that commence construction after the date of that proposal of the revised standard of performance would be subject to that standard, but not sources that commenced construction earlier.*

88 *Fed. Reg.* at 33,289 (emphasis added). Those policy goals, however laudable, do not give EPA the authority to rewrite the express language of the statute.

As discussed, the judicial review provisions of the Act also provide additional support for these concerns since any challenger has only 60 days to petition for review of an NSPS following its publication in the *Federal Register*. Any regulated entity intending to start construction during the period of applicability of these rules will have no way to challenge the requirements for 2032, 2035, or 2038 in the future in the event EPA has predicted their availability incorrectly. This is yet another reason why the Agency is limited to assigning a BSER that "*has been* adequately demonstrated"—that is, one that is available *now*.

d. EPA's phased approach conflates new and existing sources, contravening the structure of the Act.

EPA's assertion of authority to promulgate a phased NSPS fails for yet another reason—it is inconsistent with the Act's distinction between new and existing sources, and the different requirements for and standards applicable to each. The structure of section 111 directs EPA first to promulgate standards for "new sources" in a category, and then to promulgate guidelines for existing sources that could not be regulated as new sources. The existing source standard does not apply to statutory new sources, because new sources are already required to be built to the state-of-the-art BSER. EPA has turned this process on its head.

A statutory "new source" is one the construction or modification of which takes place after publication of a proposed or final NSPS. 42 U.S.C. § 7411(a)(2). An "existing source," by contrast, is "any stationary source other than a new source." 42 U.S.C. § 7411(a)(6). But under EPA's proposed rule, a "new source" would have to continue to be a statutory "new source" until at least 2038 in order to allow the 2023 standards to continue to apply to the source. This would also need to be true if, as EPA recognizes, the Agency subsequently proposes a new NSPS after 2023 but prior to 2038. In that situation, there would effectively be two different "sets" of new sources—those subject to the 2023 standards and those subject to the new NSPS proposed after 2023. The above-quoted excerpt from the Proposed 111 Rules makes this abundantly clear: "[T]he second and third phases of the standard of performance, if finalized, would apply to affected facilities that commence construction *after the date of this proposal*," notwithstanding EPA's promulgation of any subsequent NSPS. 88 *Fed. Reg.* at 33,289. However, this would mean that a new source beginning construction in 2023 would be both a section 111(b) "new source" and a section 111(d) "existing source" at the same time.

The statute does not allow for such a situation, as the two are mutually exclusive categories. Because EPA retains continuing authority under section 111(b) to promulgate a new NSPS (and thus to create a new class of statutory "new sources") at least every eight years, EPA may act to require CCS and low-GHG hydrogen as part of BSER for new sources at the time CCS and low-GHG hydrogen are actually adequately demonstrated. But what EPA may not do is shoehorn a decades-spanning rule into a statutory eight-year cycle based on its "projection" that technologies will be adequately demonstrated many years into the future.

e. Given these concerns, EPA should not finalize a phased approach.

EPA lacks a sufficient legal basis to propose phased standards for natural gas-based units. And, given the lack of record evidence supporting its assertions—discussed in detail *infra* in these comments—the duplication of those requirements for existing sources is likewise invalid. EPA should repropose or significantly supplement its proposed guidelines for existing natural gas-based turbines to ensure that these rules are workable and achievable across the industry. For new units, and as EEI proposed to the Agency in its February 2023 whitepaper to the Agency's non-regulatory docket, the Agency should adopt an approach that incorporates efficiency-based standards for these units today, while setting "capable" requirements that enable future retrofits of these technologies *when they become available* in the future.[56] Such an approach would better within EPA's statutory and regulatory authorities and be consistent with existing case law.

B. CCS Technology is an Important Emerging Technology but All Constituent Elements of the Technology Have Not Been Adequately Demonstrated in an Integrated Way, Making the Proposed Emissions Rates Unachievable.

EPA proposes to determine that CCS is adequately demonstrated for existing coal-based units as well as for new and existing natural gas-based units. For coal-based units, EPA proposes that

[56] *See* Appendix B.

units that plan to operate after 2040 in the long-term subcategory, achieve a unit-specific emissions limitation reflecting a 90 percent capture rate be required by 2030. *See* 88 *Fed. Reg.* at 33,341. For natural gas-based units, the Agency proposes as a second phase of BSER for both new base load and existing units that opt for the CCS-based pathway that BSER would lead to a unit specific emissions limitation representing the installation of CCS at a 90 percent capture rate by 2035. *See id.* at 33,283.

Electric companies have long recognized the importance of carbon capture and storage technologies in addressing emissions from fossil-based EGUs. Many EEI member companies have been working for over a decade—and continue to work toward developing and improving CCS technologies—with the goal that these will be able to meet industry performance and customer cost requirements in the future. Continued research, development, demonstration, and deployment (RDD&D) is critical for the long-term success of CCS. EPA and other federal government agencies, including the DOE, should continue to collaborate on these RDD&D efforts.[57]

However, despite EPA's assertions in the Proposed 111 Rule, CCS is not adequately demonstrated, commercially viable, nor cost effective even when the new tax incentives for existing coal-, new natural gas-, or existing natural gas-based units using CCS are taken into

[57] These RDD&D efforts are important beyond the power sector. CCS will be needed not only to reduce emissions from fossil-based electricity generation, but from other commercial and industrial processes, both in the U.S. and around the world, and this essential detail has been recognized by policymakers for at least a decade. *See* International Energy Agency, *Technology Roadmap – Carbon Capture and Storage* (2013), https://webstore.iea.org/technology-roadmap-carbon-capture-and-storage-2013.

consideration. The efforts by EEI member companies as well as universities, DOE, and international organizations and governments have not yet resulted in CCS systems that perform at the levels that EPA would require for compliance. The various CCS studies and demonstration projects that EPA cites with respect to existing coal-based power plants highlight that the technology remains in the development and demonstration phase, not the commercialization and deployment phase, and that the capture levels proposed are not yet achievable.

Moreover, even if EPA is correct that some level of capture may have been demonstrated, CO_2 pipelines exist, and some small pilot storage projects have gone forward, EPA's record does not support the adequate demonstration conclusion that the Agency proposed to draw. This is because EPA's assessment of the adequate demonstration of CCS is purposefully myopic, focusing only on whether each constituent element of CCS has been demonstrated, without addressing whether all three elements of the system of CCS that would be needed for compliance have been demonstrated or could be permitted and constructed in time to allow for compliance on the timeline that EPA has projected. Further, EPA has not addressed the significant legal, regulatory, and insurance issues that must be resolved before CCS could be deployed across the industry for compliance. These issues include the development of workable legal and regulatory regimes to address liability for long-term storage of CO_2.

A technology determined to be BSER may not need to be in wide commercial operation, but EPA must show that the standards that result from the application of BSER are achievable. No one has integrated all three of these elements of CCS such that the Agency can demonstrate that it possible to achieve the CCS-based emissions rates that EPA proposes for both existing coal-

based units and new and existing natural gas-based units. EPA's assertions about the need for "lead time" highlight that the proposed emissions limits are unworkable unless all three elements can be stitched together. EPA cannot point to anything in the record that would support the Agency's assessment that this system of emissions reduction, as a system, has been adequately demonstrated or that the resulting emissions limits are achievable. Without the integration of all three constituent elements of CCS and assurances that these elements can be developed and deployed along the timelines that EPA asserts are feasible, EPA is hazarding guesses about the achievability of the standards on the required timelines.

1. EPA cannot show that a 90 percent capture rate has been demonstrated such that units could comply with the proposed emissions limits.

EPA principally relies on the experience of the Petra Nova and SASK Power facilities to determine that capture at a 90 percent rate is adequately demonstrated for coal-based units. However, EPA's reliance on these projects is misplaced as neither is (or was) capable of consistently capturing 90 percent of the total CO_2 emissions from the facility.[58]

The Petra Nova capture system was designed to capture 90 percent of 37 percent of the flue gas produced by a single EGU that was part of the larger facility—amounting to a total capture of 33 percent of the total CO_2 emissions.[59] This means that the facility, which is now closed, was capable of capturing carbon from a large slip stream, not the entire flue gas, as would be required by EPA's proposed emissions limits.

[58] EPA should consider the experiences of all CCS demonstration projects in assessing the adequate demonstration of this critical technology. For example, EEI member AEP is providing significant information about its Mountaineer project via comments filed in this docket.

[59] EIA, Today in Energy, Petra Nova is One of Two Carbon Capture and Sequestration Power Plants in the World (Oct. 17, 2017), https://www.eia.gov/todayinenergy/detail.php?id=33552.

Even for that slip stream, high rates of capture were not achieved regularly while the unit was in operation. According to one report, based on EPA emissions data, the capture rate for the CO_2 in the Petra Nova slip stream may have been as low as 65-70 percent, not the 90 percent for which the system had been designed.[60] The GeoEngineering Monitor reported that the Petra Nova capture facility experienced more than 360 downtime days between 2017 and 2019 due to technical problems—nearly one third of days of operation.[61] This level of inconsistency in operations would not meet industry performance requirements for generating units, nor would it allow a unit to demonstrate compliance with EPA's proposed emissions limits using the metrics that EPA proposes to use, which would require more consistent operation of the capture equipment. This would place units at risk of not being able to comply, despite best efforts.

EPA also relies on SASK Power's Boundary Dam Unit 3 to prove adequate demonstration of CCS for coal-based units and the proposed 90 percent capture rate. *See* 88 *Fed. Reg.* at 33,346. While the facility has been in operation since 2014, SASK Power also has struggled to keep the CCS facility operational and to achieve sustained high levels of performance of the capture system. Only recently, after nine years of operation, has the facility been able to more consistently operate at levels nearing design rates, but has mostly operated around a 70 or 75

[60] *See* S. Mattei and D. Schlissel, Institute for Energy Economics and Financial Analysis, *The Ill-Fated Petra Nova CCS Project: NRG Energy Throws in the Towel* (Oct. 5, 20220, https://ieefa.org/resources/ill-fated-petra-nova-ccs-project-nrg-energy-throws-towel.

[61] Anja Chalmin, *The Current State of CCS in the U.S.-- Résumé after 100 Years of CO_2 Capture and 25 Years of Extensive Federal Funding*, Geoengineering Monitor (Dec. 2, 2022), https://www.geoengineeringmonitor.org/2022/12/the-current-state-of-ccs-in-the-u-s-resume-after-100-years-of-co2-capture-and-25-years-of-extensive-federal-funding/.

percent capture rate.[62] But, the facility has only intermittently been able to capture the designed 90 percent capture rate, despite significant efforts and major outages to address issues with the operation of the capture system.[63] And, in 2021, even after improvements were made, Boundary Dam was only able to achieve less than a 37 percent capture rate.[64] Accordingly, this project does not support EPA's determination that CCS is BSER, nor that the proposed resulting emissions limitations, based on continuously achieving a 90-percent capture rate, is achievable.

Moreover, while EPA may hope that time will address operational concerns with capture systems, SASK Power's efforts reveal that much more time than EPA anticipates may be necessary. If a consistently high rate of capture cannot be sustained after nine years of operation at Boundary Dam, it is not clear how EPA has determined that a 90-percent capture rate will be possible consistently by 2030 or that a 96-percent capture rate will be demonstrated in 2038. EPA does not address any of these issues in its assessment of either facility.

Neither Petra Nova nor Boundary Dam can consistently capture 90 percent of the CO_2 from those facilities. EPA, therefore, cannot show that this level of capture is adequately demonstrated for purposes of the Proposed 111 Rules. While EPA may not have to show that the proposed

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[62] *See* Dominika Janowczyk, et al., *Derates and Outages Analysis - A Diagnostic Tool for Performance Monitoring of SaskPower's Boundary Dam Unit 3 Carbon Capture Facility*, 15th International Conference on Greenhouse Gas Control Technologies GHGT-15 (Apr. 6, 2021), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3820207.

[63] *See id*.

[64] S&P Global Market Intelligence, *Only Still-Operating Carbon Capture Project Battled Technical Difficulties in 2021* (Jan. 6, 2022), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/only-still-operating-carbon-capture-project-battled-technical-issues-in-2021-68302671. Frequent capture system outages also undermine EPA's assertions about the costs of CCS.

BSER is already deployed broadly, it must at least have some evidence that the technology can do what EPA would require an affected source to accomplish via application of that technology.[65]

While some aspects of carbon capture technology are mature, consistent performance is not yet assured. Throughout the Proposed 111 Rules when describing carbon capture technologies, EPA correctly refers to the ongoing research and activities as "emerging," "possibility," "expected," and "in development," and noting "intentions" to undertake efforts that will continue efforts to develop and demonstrate capture. Each of these terms correctly describes capture as a technology that is still under development.

2. EPA's Assertions about the Costs of CCS Are Not Reliable.

EPA also asserts incorrectly that the costs of CCS for existing coal-based units have been and will continue to decrease such that these costs are reasonable not an impediment to determining that CCS is BSER. *See* 88 *Fed. Reg.* at 33,367. However, the experience of EEI's member companies is that the numerous examples of planned and delayed or abandoned projects are proof of the opposite. Moreover, most projects to date have received significant federal and other governmental funding, which highlights that the costs of the technology to the industry—and customers—is not yet acceptable. Finally, EPA is not correct that the recently passed 45Q tax incentives will ameliorate these costs concerns. The tax incentives will help address cost concerns, but that help will be limited.

[65] EPA does not address whether the Agency would be willing to exercise enforcement discretion if capture facilities do not operate at levels, or as consistently, as would be required for compliance with final standards. If EPA finalizes the CCS-based standards as proposed, the Agency should be clear that it would exercise such enforcement discretion. This does not insulate units from citizen enforcement suits but would send strong signals to courts about whether enforcement was appropriate.

a. EPA's estimates assume CCS is a mature technology and are inconsistent with best practices for assessing costs for new technologies.

Because there is only one operating coal-based CCS project operating today, EPA's cost data in support of its BSER determination is based on modeling and other studies and not real-world costs. EPA relies heavily on an analysis conducted by Sargent & Lundy, LLC, in which the authors explicitly recognize that "[d]ue to the limited availability of actual as-spent costs for CO_2 capture projects, the cost estimation tool *could not be benchmarked against recently executed projects* to confirm how accurately it reflects current market conditions."[66] Despite this limitation with the report prepared for this rulemaking, EPA asserts that CCS costs will decrease in the near term. There are several issues, however, that undermine the validity of the analysis used to support this conclusion.

As a preliminary matter, EPA's assertion that near-term costs for CCS will decrease is not supported by the reality of planned projects that have been put on hold or abandoned.[67] While it is true that deployment reduces costs, CCS deployment has not occurred at levels to demonstrate that EPA can rely on these decreases or that the Agency can accurately predict the timing and magnitude of such decreases.

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[66] Sargent & Lundy LLC, IPM Model—Updates to Cost and Performance for APC Technologies CO2 Reduction Retrofit Cost Development Methodology, Project 13527-002 (March 2023) at 1 (emphasis added).

[67] The Agency's assertion also does not recognize updated NETL guidance, which states that "[t]he Chemical Engineering Plant Cost Index indicates relatively high volatility for capital and labor costs, with the cost index rising by 30% between December 2018 and March 2022. As these fluctuations are *not* captured by the reported cost uncertainty, the reader should adjust the reported costs if required by the end use of the data." NETL, Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity (Oct. 14, 2022) at p. 4, n.b (emphasis added).

The Sargent & Lundy analysis assumes that carbon capture technology is a mature technology for purposes of its work, without a basis in fact for that assumption. Further, this EPA-sponsored analysis assumes that there have been Nth-of-a-kind (NOAK) CCS plants; there are, however, no NOAK plants. Presently, there is one operating in North America, and two other projects have been idled or operate as a traditional natural gas-based unit without any capture technology. Because the Sargent & Lundy analysis treats CCS as mature, it then draws on various National Technology Energy Laboratory (NETL) models to assess costs. However, given the emerging nature of the technology and the few existing projects, reliance on these cost frameworks is misplaced. As recent new guidelines for assessing CCS costs have asserted, efforts to estimate NOAK costs for emerging technologies must first be grounded in the costs of FOAK (first-of-a-kind) facilities and retrofit assessments are particularly fraught because of the unit-specific nature of these costs.[68]

b. CCS projects to date have received significant federal funding, which does not support a determination that the technology's costs are reasonable.

EPA's assessment of the costs of CSS as reasonable does not adequately address the significant amount of federal funding that the two projects relied on received. For example, Boundary Dam

[68] Simon Roussanaly, et al., *Towards Improved Guidelines for Cost Evaluation for Carbon Capture and Storage*, White Paper (Mar. 2021), https://www.osti.gov/servlets/purl/1779820. These guidelines assert that a better approach is a hybrid costing method that combines a bottom-up analysis of FOAK commercial cost of an advanced technology with an empirical model employing experience curves to project its future cost. They also recommend extensive analysis related to the uncertainties of such future cost estimates. These guidelines also address the intricacies of assessing costs for retrofits, which are inherently unit-specific, and which the authors note have not been well addressed to date. They call for particular attention to be paid to the following aspects: economic impact of potentially required plant production stoppages, impacts on the main output product quality and plant operation, flue gas treatment requirements, spatial constraints in plant sites, and flue gas interconnection, among others.

received CA $240 million in support from the Canadian government, as well as support from the provincial government. The project also was supported not only by the sale of electricity, but by the sale of the captured CO_2, which was used in enhanced oil recovery, as well as the sale of sulfuric acid and fly ash.[69] This combination of support indicates that the project was not economic on its own, which undermines EPA's assertions that costs are reasonable.

Similarly, the Petra Nova facility also received significant federal funding, without which it would not have been built. According to DOE, it entered into a cost sharing agreement with the project in 2010 to provide $190 million in total cost share with $167 million in financial assistance through the original Clean Coal Power Initiative (CCPI) Round 3, which included funding from the Recovery Act, and additional $23 million in February 2016 under the Section 313 of the FY2016 Consolidated Appropriations Act. Ultimately, Petra Nova received around 15 percent of the $160 million based on project recipient cost share under the Section 313 of the FY2016 Consolidated Appropriations Act mandated reallocation of funds.[70]

Federal funding support will be necessary to drive continued RDD&D of this technology and should continue, but it is difficult to say that the costs of a technology are not an impediment to a BSER determination when projects would not be built without such support.

c. Tax incentives will not fully offset CCS costs and may not offset costs very much at all.

[69] *See* Massachusetts Institute of Technology, Carbon Capture & Sequestration Database, Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project. Due to the decreased capture rate, Boundary Dam had to pay penalties to the CO_2 offtaker in 2014.

[70] DOE, Office of Fossil Energy & Carbon Management, Petra Nova—W.A. Parish Project, https://www.energy.gov/fecm/petra-nova-wa-parish-project.

EPA also points to the 45Q tax incentives, which were extended and increased under the IRA, as support for the reasonableness of the costs of CCS. EPA assumes that unit owners/operators will be able to utilize the recently passed tax incentive for CO_2 storage for the full 12 years that the tax incentive will be available. *See* 88 *Fed. Reg*. at 33,346. While important for addressing some CCS project costs, is not clear that these tax incentives will meaningfully offset the increased costs associated with adding CCS to a facility.

As a preliminary matter, the IRS has not finalized the rules for 45Q for carbon capture, which means that an entity conducting a near-term carbon capture project might not be able to claim a tax incentive depending on the final rules. Moreover, the basic requirements, as per the statute, include that the credit is only available once a CCS facility is operational, and the CO_2 has been stored with some type of proof that such storage is secure. Because the tax credits are only available for ten years, or *until 2032*, it is not clear that projects using CCS to comply with the proposed standards would be able to access the tax credits for more than a few years. Based on EPA's own BSER determination that CCS technology for coal-based units will not be fully implementable by these units *until 2030*, when compliance with the proposed guidelines would be required, access to the any tax incentives for these units will be significantly limited. For natural gas-based units, CCS technology will not be implementable by EPA's estimates *until 2035*, which is notably *later than 2032*. As a result, these units will not benefit from the tax incentives at all. For existing natural gas-based turbines, EPA's cost assessments cannot include the tax incentives.

Further, given the cost analysis included in EPA's TSDs, EPA assumes that a facility will be able to capture 90 percent of the CO_2 coming off a stack and take full advantage of the tax credit offered from the moment that it commences operation, which assumes near perfect deployment of a technology that has yet to consistently reach the capture levels EPA asserts are BSER, as already discussed. While it is correct that the tax incentives are likely to encourage some CCS deployment, including potentially some retrofits, the startup and operation most likely will be in fits and starts, as evidenced by the experiences of the Boundary Dam facility, and therefore may not allow an entity to earn the full tax incentive. EPA's cost assumptions based on the existence of the tax incentives are thus aspirational and inconsistent with how the credits are structured and how new technologies are likely to perform.

3. EPA's determination that CCS is adequately demonstrated for new natural gas-based units is unsupported by the record.

The Agency proposes that CCS is the BSER for phase two standards for base load natural gas-based units, requiring that these units meet a standard equivalent to capturing 90 percent of CO_2 by 2035. *See* 88 *Fed. Reg*. at 33,283. EPA asserts that the individual component pieces of CCS for natural gas-based generation are themselves demonstrated separately, with a focus on the "capture element" at the unit itself being demonstrated "based on the demonstration of the technology at existing coal-fired steam generating units and industrial sources and combustion turbines." *Id*. at 33,291.

EPA cites one dismantled project in Massachusetts that captured CO_2 from a 40 MW "slip" stream at a natural gas-based unit via an amine system, and then piped that product directly to a food and beverage industry facility that was located adjacent to the plant for use in food products. The Agency also downplays several relevant facts this facility. This project did not

capture 90 percent of the flue gas. In addition, the CO_2 did not have to be transported via a pipeline and it did not need to be stored underground. In short, EPA relies on a facility that operated a relatively small (e.g., less than 10 percent of facility output) slip stream project to capture CO_2 for use at an adjacent facility, and which was entirely dismantled 18 years before the current proposal as its principal example for demonstration within the industry. This is not sufficient to conclude that 90 percent capture at natural gas-based units is adequately demonstrated.

While EPA tries to make up for its lack of actual, existing, on the ground examples in the power sector by detailing current capture RDD&D, this discussion mostly serves to point out that CCS technology is clearly still in an RDD&D phase. EPA points to numerous Front End Engineering Designs (FEED) studies for natural gas fired turbines that are using DOE funding. FEED studies, however, are just studies. They are not guaranteed to result in actual projects. To date, none of the six FEED studies that have been concluded have resulted in actual construction or permitting of a facility utilizing CCS. *See* 88 *Fed. Reg.* at 33,293-94.

EPA also points to recent grants and awards from DOE to begin work or study the impacts of potential deployment of CCS projects. *See id*. However, the body of evidence EPA cites—funding for studies to begin work on attempting to better understand and advance the still nascent technology with respect to natural gas-based units—serves to underscore the lack of adequate demonstration of CCS technology, rather than support EPA's conclusions that it is adequately demonstrated and part of BSER at this time.

EPA also references work being done by NETL, which conducted computer simulations of CCS on NGCC units and gathered potential cost data for specific generic facilities to be built on a greenfield. However, *these are simulations*, which are not real in any practical sense and have also not resulted in any activity to install, permit, or build CCS technology on NGCC units.

EPA strays beyond power sector studies and examines some demonstrations at coal-based steam generating units and other industrial processes, but that the experience is not comparable or applicable to natural gas-based units given the different engineering between coal powered steam turbines and natural gas combined cycle units. Moreover, as discussed above, EPA's adequate demonstration conclusion for coal-based EGUs is itself insufficient. The Agency also cites a number of small slip stream carbon capture operations and *anticipated* larger projects that it assumes will be able to meet the proposed same capture levels. *See* 88 *Fed. Reg.* at 33,292. EPA fails to address that capturing 90 percent of a five or ten percent slip stream of flue gas is a significantly different task than capturing 90 percent of 100 percent of the flue gas on a fully commercially operational EGU. In addition, as noted, unbuilt projects cannot serve as evidence that a technology can achieve the standards that EPA proposes. Again, EPA's examples only serve to underscore the lack of demonstration projects for the technology it is asserting is demonstrated.

The record in this proposal does not support EPA's determination that CCS is adequately demonstrated for new natural gas-based units. As a result, the Agency should not move forward with standards based on CCS for these units.

4. EPA's determination that CCS is adequately demonstrated for existing natural gas-based units is even less supported by the record than EPA's new source determination.

While EPA's determination that CCS is BSER for new natural gas-based units is not supported by the record, the Agency's determination that CCS is BSER for certain *existing* natural gas-based turbines is even less supported. *See* 88 *Fed. Reg.* at 33,633. EPA's BSER determination for existing natural gas-based units is identical to the Agency's proposed BSER, along with identical proposed emissions limits that would require that affected sources either install CCS with a 90 percent capture rate by 2035 or blend hydrogen at 40 percent and 96 percent in 2032 and 2038, respectively. *See id*.

The Agency notes that it relies on the same body of evidence for its BSER determination for existing natural gas-based sources as it did for the new source determination. This slim analysis consists of almost an identical set of assertions as EPA made for new units—the existence of FEED studies, modeling assumptions, tax credits to address costs, and that some efforts in unrelated industries with intentions to deploy CCS in their operations—only with less tangible evidence. *See id.* at 33,366-68.

EPA also focuses on the fact that a limited number of existing units would be required to comply with the CCS-based standards—those larger than 300 MW and operating at capacity factors of 50 percent or greater. Based on a cursory, spreadsheet-based analysis of the existing fleet, EPA notes that the CCS retrofit requirements would only cover about 35 GW of potential CCS capacity across the existing natural gas-based fleet. As a result, EPA asserts that the proposed CCS BSER determination is "reasonable" since "there will be significant time to deploy the

needed infrastructure, a total of eleven years from the likely finalization of these guidelines…in addition, it is unlikely that all of the units that EPA projects would be affected in 2035 would choose to install CCS; some would likely choose to co-fire low-GHG hydrogen…for these reasons, the EPA believes that there will be adequate capability to build enough CCS for the existing combustion turbine EGUs subject to a CCS BSER at a capacity threshold of 300 MW, given the amount of time provided." *Id.* at 33,367. This does not meaningfully address the challenges related to retrofitting CCS on existing units, which are not merely a function of time. As has been noted, these also are a function of the current design of the unit and the availability of existing space for large capture equipment.[71] EPA does not address these real issues regarding the feasibility of retrofits and how they are different from new builds.

In fact, EPA makes no mention of the fundamental difference between new and existing sources: that new sources can be designed to adopt and deploy new technologies, to the extent they are demonstrated, as part of their initial design. Existing sources, by their very definition, would be required to retrofit—a process that would involve significant capital outlay, and presents numerous potential impossibilities—including inability for sources to be redesigned to accommodate new and potentially sizeable capture technology, a lack of available unit space or water, the need for units to be down and non-operative to accommodate significant retrofit time, or the need to make potentially significant permitting modifications to already existing permits and conditions.

[71] *See* Roussanaly, *supra*, n.68.

Despite these real differences between employing CCS at new and existing units, EPA proposes that existing sources comply with standards based on CCS technology *on the same exact timeline as new sources*. Even assuming that CCS is adequately demonstrated, it is readily apparent that existing sources will face greater challenges and significant additional hurdles related to retrofitting. At minimum, this should be reflected in a different compliance timeline; but, as noted, time can only address some of the challenges of retrofits.

5. Without the capture and storage elements, EPA's proposed CCS-based standards are not achievable.

Capturing CO_2 from the flue gas of fossil-based generation would not enable compliance with the proposed standards as EPA conditions compliance on demonstrations that the CO_2 was stored in ways that EPA deems acceptable. *See, e.g.,* proposed 40 C.F.R. § 60.5555a(f). Accordingly, EPA recognizes that the transport and storage of CO_2 are necessary constituent elements of CCS as the proposed BSER.

However, while recognizing that transport and storage are integral to the successful environmental performance of CCS, EPA does not appropriately consider how these could impact EPA's BSER determination or the selection of the resulting emissions limitations or guidelines, focusing on whether they are demonstrated themselves and not on what they could mean for the achievability of the proposed standards.

i. EPA does not address the numerous supporting infrastructure challenges regarding transportation of captured CO2.

EPA makes significant assumptions regarding the availability and ease of operation of CO_2 pipelines to transport the captured carbon that would likely result from any unit installing CCS as part of compliance with EPA's BSER determination. EPA assumes that CO_2 pipelines will be

available to transport the captured CO_2 from all of the facilities required to install CCS by 2030 or 2035 for coal-based and natural gas-based units, respectively, yet admits that there are only CO_2 pipelines in 11 states today. The Agency lists a number of CO_2 pipelines that have been announced, noting that they are "likely to be developed" and have been in the planning stage for in some cases four years. *See* 88 *Fed. Reg.* at 33,366. However, "likely to be developed" does not mean "has been developed" or "will be developed," and does not provide assurances to the EGUs that there will be CO_2 transportation available when needed. Critically, these pipelines are outside the purview of EGU owner/operators and EEI member companies would need to depend on other parties to develop the infrastructure and build it successfully inside the next decade.

The status of the CO_2 pipelines cited by the Agency follows:

- *Midwest Carbon Express*: According to Summit Carbon Solutions' website, the entity developing the 2,067-mile Midwest Carbon Express CO_2 pipeline, they have reached agreements with over 2,700[72] landowners with an undisclosed number that still remain. Summit announced in 2021 that they are building the Midwest Carbon Express with the goal of completing the pipeline in 2024. Given that not all the land-lease rights have been approved, the timing of completion is uncertain.[73]

- *Heartland Greenway Phase 1A +1B*: the 1,302-mile pipeline announced its first permit filing in Iowa 2022, it too crosses several states (NE, IA, SD, MN, and IL) whereby each state, county and landholder will require approvals or agreements and hopes to have the initial system commissioning in 2025.

- *Mt. Simon Hub*: According to the developer—Wolf Carbon Solutions—the 280 mile Iowa-centric pipeline began community outreach efforts in the first quarter of 2022 with a projected in-service date is 2025.[74] However, Wolf Carbon Solutions does not have all of

[72] Summit Carbon Solutions, https://summitcarbonfacts.com/.

[73] Adam Willis, Massive Midwest pipeline, a test for North Dakota's carbon capture goals, hits landowner snags, AgWeek Business (Dec. 4, 2021), https://www.agweek.com/business/massive-midwest-pipeline-a-test-for-north-dakotas-carbon-capture-goals-hits-landowner-snags.

[74] *See* Wolf Carbon Solutions, https://wolfcarbonsolutions.com/mt-simon-hub/.

> its easements in Iowa and plans to try and get voluntary easements from landowners whereas both Midwest Carbon Express and Heartland Greenway are resorting to eminent domain which falls under each states' jurisdiction.[75] Wolf Carbon Solutions filed a permit application with the Illinois Commerce Commission in June 2023. The pipeline is projected to be operational also in 2025 but has not started construction.

EPA tries to counter these obvious concerns by noting in the Greenhouse Gas Mitigation Measures for Steam Generating Units Technical Support Document (TSD) by listing "planned or announced" pipelines to try and support that CO_2 pipelines will be available and are expanding. While they may be expanding, CO_2 transportation is not yet widely available, and the regulatory hurdles to increased deployment are significant.[76] It should be noted that each of the announced or planned pipelines requires years to obtain permits and get financing. Moreover, they will not be available for any new CCS projects that would be motivated by compliance with EPA's standards and instead will be dedicated for the use of specific facilities/customers. In particular, these pipelines, therefore, do not necessarily represent available capacity for coal-based EGUs that EPA is proposing that they must install CCS *by 2030*.

Moreover, given the absence of federal authority, siting and economic regulation of CO_2 pipelines generally falls to the states. As a result, eminent domain authority for CO_2 pipeline projects depends on and varies by the states. This is a time-consuming process. Where states do not provide eminent domain authority, pipeline developers must depend on reaching agreements with each landowner to obtain rights-of-way. In addition, in some states, project developers must

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[75] *See* Jared Strong,Wolf proceeds with voluntary pipeline approach despite neighbors' growing blockade, Iowa Capital Dispatch (Apr. 7, 2023), https://iowacapitaldispatch.com/2023/04/07/wolf-proceeds-with-voluntary-pipeline-approach-despite-neighbors-growing-blockade/.

[76] *See* J. Garofalo and M. Lewis, *Sources to Sinks: Expanding A National CO_2 Pipeline Network*, Environmental Law Institute (Jan. 1, 2020).

go county by county to seek approval from each jurisdiction. The diffuse nature of the regulatory regime for CO_2 pipelines creates multiple opportunities for opponents to slow or stop project development, which infuses uncertainty into the process and can be a significant barrier to getting investor interest in CO_2 pipeline projects and to getting this necessary infrastructure ultimately built. These regulatory delays and the potential lack of community acceptance for the CO_2 pipelines are one more challenge for any EGU to demonstrate compliance with the proposed standards. Moreover, EPA has not provided any evidence that its assumptions about how quickly new pipelines could be built—in some instances in 3.5 years—are grounded in actual experience permitting and siting these transmission facilities. It certainly is not consistent with the recent experiences siting and permitting new natural gas or oil pipeline.

ii. EPA's analysis ignores challenges related to permitting new storage facilities, including advocacy group opposition.

EPA acknowledges that not all EGUs have equal access to appropriate geologic storage. However, even if these access challenges could be addressed via pipeline deployment, EPA still have not addressed the challenges related to permitting new storage facilities. While regulations exist to permit storage facilities under the Safe Drinking Water Act's Underground Injection Control Program, EPA has issued one such permit to date.[77] As a result, a significant number of new storage facilities would need to be permitted in order to allow for EGUs to comply with the proposed CCS-based emissions limits. EPA has not addressed whether it has the resources to undertake this expansion in permitting needs.

[77] *See* EPA, Class VI Wells Permitted by EPA, Table, https://www.epa.gov/uic/class-vi-wells-permitted-epa#table. The Table lists several pending permit applications, but provides no information about when those were filed or how long they have been under consideration by EPA.

States could elect to issue these permits to address the potential future demand for new storage sites, but, at this time, only North Dakota and Wyoming have been granted primacy to do so.[78] The challenge for states seeking primacy is significant. For example, Louisiana currently is seeking primacy, but EPA has moved slowly to act on the state's application. In addition, many of the same groups that advocate for EPA to determine that CCS is adequately demonstrated actively oppose Louisiana's quest for primacy. The concerns that they have raised in their comments on the application indicate that they are likely to oppose other states' future primacy efforts (and future CCS projects generally) because they do not want the technology deployed. For example, in urging EPA not to accept Louisiana's application for primacy, the Sierra Club both proposed a list of additional, unrelated requirements designed to make Class VI unobtainable (e.g., requiring that all other, non-CO_2 wells be plugged first) and asserted that "[c]arbon capture and sequestration is not a step in the direction of a clean energy economy. It is an unproven technology, a false solution, and far too expensive." *See* Sierra Club letter, Appendix D. Similarly, the Center for Biological Diversity (CBD) opposed primacy, stating that "[a]s a foundational matter, we reject the premise that CCS is a necessary—or even appropriate—approach to addressing the climate crisis and pollution burdens borne by frontline and fenceline communities. After billions of dollars of investment and decades of development, deployment of CCS has consistently proven to be ineffective, uneconomic, and unwise." *See* CBD letter, Appendix E. Given this level of opposition to a state having permitting authority for CO_2 injection wells, it seems clear that these groups also will oppose applications for actual

[78] *See* EPA, Primary Enforcement Authority for the Underground Injection Control Program, https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0.

storage facilities, as well as the other constituent elements of CCS. At minimum, this level of opposition should be factored into EPA's timelines.

6. Adequate demonstration determinations that result in standards that are not achievable can harm broader efforts to develop and demonstrate key technologies needed to reduce GHG emissions.

Ironically, EPA's proposed standards, if finalized, could have the unintended consequence of dissuading companies from moving forward with projects that would help address the concerns with CCS performance and costs identified in these comments. It is one thing to test a new technology to learn more about its costs and operation, but it is another to subject that test project to the CAA's enforcement regime. If the potential owners and operators of these projects are not confident that they can demonstrate compliance with the proposed standards, which would require consistent performance of not only the capture systems, but also the related pipeline infrastructure and storage facilities, they may choose not to move forward to avoid compliance penalties. Rather than face non-compliance, project advocates and their investors may prefer to take less risk—and not build or retrofit facilities. In this way, stringent standards can slow down RDD&D efforts.

Section 111 already acknowledges that new technologies may not operate as expected and that some relief from strict compliance with standards might be necessary to encourage deployment of new technologies. Specifically, section 111(j) provides for innovative technology waivers in the event that the owner or operator of a new unit would like to employ an emerging technology. *See* 42 U.S.C. § 7411(j)(1)(A). These innovative technology waivers are not available, however, if a technology is adequately demonstrated, so they could not be sought if EPA determines in any final rules that CCS is adequately demonstrated. These waivers also likely will not be available

to address concerns about consistent performance of capture systems as they are intended to provide some regulatory relief only to systems of continuous emissions reduction. *See id*. at §§ 7411(j)(1)(A)(i) and (ii). Regardless, the existence of section 111(j) highlights that the Act contemplates that strict regulatory regimes can serve to discourage deployment of emerging technologies that could ultimately result in better environmental performance.

One way to address concerns that stringent standards and inflexible compliance demonstration requirements may harm RDDD&D efforts is via enforcement discretion. As noted, EPA has not indicated that it is willing to exercise any enforcement discretion if CCS does not perform as expected. At minimum, EPA should be clear that it would consider exercising enforcement discretion to support RDD&D efforts.

7. EPA should consider alternative approaches.

Ultimately, the Agency's proposed determination that CCS is the BSER for all affected sources across its three proposals falls short for separate reasons for each rulemaking. As a result, and in order to finalize rulemakings that are durable and will continue to drive progress across the electric sector, EPA should consider not finalizing the proposed determination that CCS is BSER for existing coal-based units, new natural gas-based units, or existing natural gas-based units. For existing coal-based units, there are a variety of other options that EPA could consider as BSER—several of which the Agency has determined on an individual basis are BSER for certain other subcategories of sources. The Agency should consider using these approaches instead.

For new natural-gas based units—and as noted *infra*—EPA should focus on ensuring continued emissions progress through the use of efficiency-based approaches, like the Agency has proposed

in its phase one approaches and should set additional requirements that these units be capable of CCS (or hydrogen) retrofits/conversions in future years once the technology matures and is adequately demonstrated. At present there are limited options for reducing emissions other than improved efficiency. In the future, however, new natural gas units may be able to blend hydrogen or use carbon capture technology to reduce emissions in ways that satisfy industry performance and customer cost requirements—in addition to or instead of efficiency measures. EPA can set a hydrogen *or* carbon capture "capable" standard now in conjunction with this traditional emissions rate-based efficiency approach. This would ensure that any new generation not only would use the most efficient technologies available—as regulated by the lb CO_2/MWh emissions limitation or through a mass-based compliance option in terms of tons of CO_2—but also could enable future emissions reductions once hydrogen or carbon capture technologies are demonstrated and cost effective for the power sector, while supporting reduced outage times associated with retrofits.[79] It would send clear signals that owners and operators should be thinking about the future operation of these units.

For existing natural-gas based units, EPA should repropose or significantly supplement its insufficient proposal and instead focus on conducting significant more analysis to propose a workable set of guidelines for these sources, one that is both justified technically and also—as

[79] "Capable" standards—sometimes referred to as "ready" or "capable-to-ready" standards—are not self-executing. Any future emissions limitations for then-existing units based on hydrogen co-firing or CCS technology would have to be the result of a future rulemaking under CAA section 111(d) in which EPA would analyze whether such technologies had been adequately demonstrated considering all the statutory factors. The statutory text of CAA section 111 itself supports a flexibility-centered approach to both standard setting and compliance, but not automatic increases in the stringency of standards.

discussed *supra* and *infra*—works in conjunction with the other proposed rules and the Administrator's announced holistic approach.

C. Hydrogen Blending is a Promising Approach For Reducing Emissions From The Power Sector But is Not Adequately Demonstrated Today.

EPA's interest in hydrogen as a technology to reduce power sector emissions is well-founded and is shared by EEI's member companies. EEI and its members believe in and are working to make clean hydrogen commercially available at scale. We are engaged in pilot and demonstration projects across the clean hydrogen value chain, including participating in approximately half of the Regional Clean Hydrogen Hub (H2Hubs) proposals that were encouraged by the U.S. Department of Energy (DOE) to submit full applications; we are working with agencies and the National Laboratories to help advance clean hydrogen technology, delivery, and safety; and we are designing the power generation facilities of the future to be hydrogen capable.

This potential tool holds promise and should be maintained as a compliance option regardless of whether EPA finalizes the Proposed 111 Rules. However, electric companies also recognize that the United States is in the nascent stages of development of the clean hydrogen fuel that will be necessary to support hydrogen blending across the economy and throughout the U.S. power sector in a manner that preserves reliability and affordability. This is evident from the various government and industry efforts underway across the hydrogen value chain—including and in addition to EEI member companies' efforts—on pilot and demonstration projects, to scale up electrolyzer manufacturing and bring down costs, to shore up necessary infrastructure, and to create the regulatory certainty needed to secure the financing and long-term offtake that ultimately will drive deployment. As discussed below, these areas of development and scale-up, many of which are detailed in DOE's *Pathways to Commercial Liftoff: Clean Hydrogen* (Clean

Hydrogen Liftoff Report),[80] still must be realized to ensure development of a U.S. clean hydrogen market at scale.

As discussed *infra*, not only is hydrogen blending in the power sector not adequately demonstrated at present, but to progress from the current hydrogen market at the necessary scale that will be needed to support reliable hydrogen blending in the power sector, a number of barriers must be overcome. These include cost barriers, technical concerns, regulatory hurdles, feasibility questions, and availability issues. These challenges permeate the core elements of the hydrogen system that are necessary to enable its potential use in the power sector. Although the current industry currently has some components of the value chain that will be needed to support achievability of hydrogen blending throughout the power sector, nearly every component faces these barriers and it has yet to put all of the pieces together and confirm that they operate as a cohesive whole. This work is no less than critical for the entities regulated under the Proposed 111 Rules—this is the *only* source category with a public service obligation to operate and the entities making up this category face penalties for failing to provide reliable electricity to their customers. While EEI and its members believe these challenges are surmountable and efforts are underway to resolve them, it is unclear when, how, and to what extent these challenges will be overcome and what the impact will be on the timing and scale of deploying clean hydrogen.

[80] U.S. Dep't of Energy, Pathways to Commercial Liftoff: Clean Hydrogen (Mar. 2023), https://liftoff.energy.gov/clean-hydrogen/. Furthermore, it has been observed that DOE's recently issued *U.S. National Clean Hydrogen Strategy and Roadmap* "includes 110 'actions' that the U.S. government plans to take by 2025, 2029 and 2035, although most of these might be better be described as 'aims' or 'goals', and many are already under way." L. Collins,, U.S. unveils national clean hydrogen strategy and roadmap based around three key priorities, Hydrogeninsight (June 6, 2023), https://www.hydrogeninsight.com/policy/us-unveils-national-clean-hydrogen-strategy-and-roadmap-based-around-three-key-priorities/2-1-1462445.

As noted, DOE recently released the Clean Hydrogen Liftoff Report, which explores and discusses current opportunities and barriers to achieving commercial liftoff for clean hydrogen in the United States. This detailed report was "developed through extensive stakeholder engagement and a combination of system-level modeling and project-level financial modeling"[81] and draws on several dozen current articles, papers, and studies. As such, this report provides useful insight into the areas of developmental need that must be met to catalyze a U.S. clean hydrogen market at scale, efforts and strategies to overcome these gaps, and the potential impacts on liftoff.[82] In recognition of the fact that we are in the early stages and much remains unsettled, DOE explicitly cautions readers that "just as in any rapidly evolving industry, figures and numbers in this report will evolve based on additional learnings from researchers and industry, points of regulatory clarity (as released), and more. As such, this report should be viewed as a living, work-in-progress document that will be updated at a regular cadence."[83]

While EPA mentions some of the challenges noted in the Clean Hydrogen Liftoff Report and discussed below, it does not thoroughly or substantively grapple with these challenges in reaching its proposed adequate demonstration determinations. This is evident from EPA's proposed determinations regarding power sector access to low-GHG hydrogen, the infrastructure needed to support power sector access to low-GHG hydrogen, and the cost-effectiveness of low-

[81] U.S. Dep't of Energy, The Pathway To: Clean Hydrogen Commercial Liftoff, https://liftoff.energy.gov/clean-hydrogen/.

[82] The issuance of this report is itself evidence of the fact that there are challenges that must be overcome.

[83] Clean Hydrogen Liftoff Report at 7.

GHG hydrogen. The current reality of where the United States is and the required work ahead stand in stark contrast to the conclusory statements that underlie EPA's proposed adequate demonstration determinations. EPA's Proposed 111 Rules risk placing additional pressure on the current challenges that government and industry are working to overcome and could imperil, rather than support, the realization of a U.S. clean hydrogen economy at scale. While EEI and its members are working towards and hope that EPA's vision becomes a reality, the very fact that these are projections runs counter to the CAA's explicit language and the line of D.C. Circuit cases considering it, as discussed *infra*.

Moreover, throughout the preamble to the proposed standards, EPA overstates, uses incorrectly, or omits facts relevant to the current state of the hydrogen market and the availability of hydrogen blending today and in the near future. These include statements regarding the current use of hydrogen in the power sector, as well as multiple projections related to power sector access to low-GHG hydrogen under the timelines provided in the Proposed 111 Rules. As a consequence of EPA's failure to develop an adequate record and appropriately analyze the current state and the well-documented challenges to growth of the hydrogen sector, the Proposed 111 Rules are insufficient. Moreover, the Agency's improperly analyzed record has led it to the incorrect conclusion that, at present, low-GHG hydrogen blending for the power sector has been adequately demonstrated under the CAA.

1. EPA's reliance on pilot projects and potential future awards to set up supportive infrastructure is insufficient to determine hydrogen blending is adequately demonstrated as BSER under CAA section 111.

As discussed *supra*, in order to establish a standard of performance under section 111 that has been adequately demonstrated, EPA must determine that: (1) the system of emissions reduction

upon which the emission limitation is based is "adequately demonstrated," and (2) the emission limitation is "achievable."[84] In general, courts have determined that, in order for a technology to be adequately demonstrated, EPA needs to show that both (1) the technolog is deployed in commercial-scale operations, as well as (2) the emission limitation is achievable throughout the industry.

More specifically, existing precedent consistently supports the fact that, in order to be adequately demonstrated under section 111, a system must at least be in commercial-scale use in the relevant source category or by a source of comparable design and function. In *Essex Chemical Corp. v. Ruckelshaus*, the D.C. Circuit examined EPA's standards for sulfuric acid plants based on dual absorption systems. *Essex Chem. Corp. v. Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973). Such systems were in operational use in a U.S. elemental sulfur burning plant at the time that EPA conducted its testing for the standards. *Id.* at 435-36. As such there was no dispute about EPA's conclusion that dual absorption systems were adequately demonstrated for elemental sulfur burning plants. *Id*. However, the court noted that "there is nothing in the record to indicate any basis for the conclusion that the dual absorption process can perform efficiently in a recycle, or spent acid, plant. As such, dual absorption simply has not been 'adequately demonstrated' within

[84] In setting the requirement that a system be adequately demonstrated, Congress "stated three other key criteria – cost, non-air quality health and environmental impact, and energy requirements – as factors the EPA must take into account." *Am. Lung Ass'n v. EPA*, 985 F.3d 914, 952 (D.C. Cir. 2021) (citing 42 U.S.C. § 7411(a)(1)). The D.C. Circuit has further explained that "[a]n adequately demonstrated system is one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way." *Essex Chem. Corp. v. Ruckelshaus*, 158 U.S. App. D.C. 360, 486 F.2d 427, 433 (1973). *See also Am. Lung*, 985 F.2d at 962; and *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) (whether a system is adequately demonstrated "cannot be based on 'crystal ball' inquiry") (citation omitted). These principles are discussed more fulsomely *supra* in this section.

the meaning of § 111(a)(1) of the Clean Air Act . . . for use with *other than elemental sulfur feedstock plants*." *Id.* at 435 n.19 (emphasis added).

The existing case law also supports the idea that, while an essential step along the road to adequately demonstrating a technology, *pilot scale data alone is insufficient* for adequate demonstration purposes. In *Sierra Club v. Costle*, the D.C. Circuit considered emissions control technology for coal-based EGUs. *Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981). While the discussion focused on the standards set employing wet scrubbing technology as the BSER, which was widely used at the time and was considered BSER, the court clarified that it did "not hold that dry scrubbing is adequately demonstrated technology" despite some extrapolated pilot scale data at the time in the record. *Id.* at 341 n.157. In that instance, EPA itself had recognized that "'the major uncertainty which exists with dry SO_2 removal technology is the absence of experience at large-scale facilities.'" *Id.* (citation omitted). The court therefore determined that "it would be premature to conclude that dry scrubbing is adequately demonstrated technology." *Id*. While today dry scrubbing technology is widely utilized across the industry, at the time of *Costle* in 1981, that was notably not the case.

In addition to being in commercial-scale use in the relevant source category or by a source of comparable design and function, D.C. Circuit precedent makes clear that Congress intended section 111 standards to be valid only if achievable "throughout the industry." *See, e.g., Costle*, 657 F.2d at 341 n.157 ("We see no basis on this record which would justify extrapolating from the pilot scale data to the conclusion that dry scrubbing is adequately demonstrated for full scale plants *throughout the industry*." (emphasis added)). This requirement is well illustrated by

National Lime Association v. EPA, where the D.C. Circuit concluded that the section 111 standards were unsubstantiated because "the record d[id] not support the 'achievability' of the promulgated standards *for the industry as a whole*." *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431 (D.C. Cir. 1980) (emphasis added). The Court reiterated that holding throughout the case, and further indicated that EPA itself has long recognized this fundamental rule. *Id.* at 433 ("EPA itself acknowledged in this case that 'standards of performance . . . must . . . [assure achievability of the standard for the industry as a whole] for *all variations of operating conditions being considered anywhere in the country*." (emphasis in the original)).

The court in *Portland Cement Association v. EPA* reaffirmed this basic principle. There, the D.C. Circuit considered industry claims that EPA failed to consider the impact on Portland cement kilns of older design that, if modified, could become subject to section 111 standards. *Portland Cement Ass'n v. EPA,* 665 F.3d 177, 190 (D.C. Cir. 2011). The Court upheld EPA, finding that "EPA demonstrated how *all* regulated kilns could meet [the] standards. EPA based its [particulate matter (PM)] and [SO_2] limits 'on control technologies that can be applied in *any* kiln type and achieve the same control levels that would be expected with a new kiln at similar costs.'" *Id.*

EPA's existing precedent supports setting standards that are based on commercially deployed technologies that can be achieved throughout the industry, requiring EPA to stay abreast of and mirror existing technological trends in the power sector. It does not allow the Agency—as it has done here—to point towards some limited number of current pilot projects and determine that they are sufficient evidence of adequate demonstration of the technology and further conclude

hydrogen blending is BSER for the entire power sector today. Such an approach is directly contradictory to the Agency's statutory obligations and existing case law—and is notable since, as discussed *supra*, EPA has not demonstrated that these technologies have been integrated and demonstrated holistically across the industry. As discussed at length *infra*, EPA's reliance on prospective supportive infrastructure without hard record evidence is problematic and counterfactual. Combined with an overreliance on pilot projects, EPA's determination that hydrogen blending is adequately demonstrated as BSER is therefore insufficient.

2. EPA's proposed conclusions regarding power sector use of low-GHG hydrogen are based on an insufficient record that does not support its proposed that the technology is adequately demonstrated.

EPA's Proposed 111 Rules include critical overstatements about current power sector use of hydrogen blending. For example, EPA states that "a range of cost-effective technologies and approaches to reduce GHG emissions from these sources are available to the power sector, and multiple projects are in various stages of operation and development – including . . . co-firing with lower-GHG fuels." 88 *Fed. Reg.* at 33,242. The Agency similarly notes that "recently, utility combustion turbines in the power sector have begun to co-fire hydrogen as a fuel to generate electricity." 88 *Fed. Reg.* at 33,254-545. These statements suggest a more mature level of development than is reflected in reality.

EPA also myopically focuses on the state of combustion turbine technology to support its proposed adequate demonstration determinations. However, combustion turbine technology to blend low-GHG hydrogen is still advancing and, critically, is only one component of the infrastructure necessary for the power sector to reliably and affordably obtain and blend low-GHG hydrogen. As such, the state of combustion turbine technology alone, regardless of its level

of advancement, is insufficient to support EPA's proposed adequate demonstration determinations.

a. Despite EPA's statements, hydrogen blending in the power sector is nascent at present and any conclusions about when it will be adequately demonstrated are premature.

As discussed below, the current use of hydrogen blending in the power sector remains at the pilot stage. In fact, EPA does not cite a single U.S. power sector hydrogen blending project that is in commercial operation, and it does not since there are none to cite despite the significant government and industry efforts to overcome existing barriers.[85] Current hydrogen blending projects do not include critical components of the larger value chain that will be needed to support low-GHG hydrogen availability throughout the power sector. As discussed *supra*, the pilot and demonstration projects that EPA cites are insufficient under D.C. Circuit caselaw to satisfy the requirements for adequate demonstration, as are companies' "plans" and "expectations" for future hydrogen blending.

i. EPA overstates the current state of power sector hydrogen blending projects, as the current state of projects do not support EPA's proposed determination that it has been adequately demonstrated.

EPA's characterization and analysis of the state of hydrogen blending in the power sector are overstated, as evidenced by the Agency's own descriptions of actual current projects as "plans," "pilots," "demonstrations," and "test-burns." *See, e.g.,* 88 *Fed. Reg.* at 33,255. Use of this language is not limited to a few examples but permeates EPA's recitation of the specific facts for each of the current U.S. projects that the Agency discusses.

[85] The United States is not alone in this early phase of development—with the exception of a single, 320-kW project in Japan that is not comparable in size to the facilities subject to the Proposed 111 Rules, every project that EPA cites is in the testing stages.

Specifically, EPA: (1) describes the Long Ridge Energy Generation Project's (Long Ridge Energy Terminal) hydrogen blending as the successful completion of "a *test burn* of 5 percent (by volume);"[86] (2) explains the Intermountain Power Agency's *plan* to "replace an existing coal-fired EGU with a Mitsubishi 840-MW combustion turbine that *will have* the capability to co-fire 30 percent by volume low-GHG hydrogen in 2025 and 100 percent electrolytic hydrogen by 2045," 88 *Fed. Reg.* at Hydrogen TSD at 8 (emphasis added); *see also id.* at 33,255, 33,305, 33,308, 33,312, and 33,365 (all describing the "plans" and "expectations" for this project); (3) notes the Los Angeles Department of Water and Power's *plan* for the Scattergood Generating Station, which "*would be* ready to co-fire a minimum of 30 percent low-GHG hydrogen . . . *when the unit becomes operational by December 30, 2029*," *Id.* at Hydrogen TSD at 8 (emphasis added); *see also id.* at 33,255 and 33,308 (describing the "plans" for the project); (4) explains that the Lincoln Land Energy Center Project "*will be* ready to co-fire up to 30 percent by volume hydrogen upon initial operation," *Id.* at Hydrogen TSD at 8-9 (emphasis added); (5) notes that El Paso Electric "*is seeking* to convert its Newman Power Station to co-fire 30 percent by volume

[86] 88 *Fed. Reg.* at Hydrogen in Combustion Turbine Electric Generating Units: Technical Support Document, at 8 (emphasis added) (hereinafter "Hydrogen TSD"). EPA also cites to sources that explain that this project was a demonstration. *See* 88 *Fed. Reg.* at nn.74 and 377-78. For example, one of the sources explains that the Long Ridge Energy Terminal "conducted a successful [5 percent] hydrogen-blending demonstration on March 30, 2022." Clark, K., GE-Powered Gas-Fired Plant in Ohio Now Burning Hydrogen, Power Engineering (Apr. 22, 2022), https://www.power-eng.com/hydrogen/ge-powered-gas-fired-plant-in-ohio-now-burning-hydrogen/. Another source that EPA cites notes that "[t]esting will continue through next year at the 5% baseline." Defrank, R., Cleaner Future in Sight: Long Ridge Energy Terminal in Monroe County Begins Blending Hydrogen, The Intelligencer (Apr. 25, 2022), https://www.theintelligencer.net/news/community/2022/04/cleaner-future-in-sight-long-ridge-energy-terminal-in-monroe-county-begins-blending-hydrogen/. EPA itself also notes that "The Long Ridge Energy Terminal tested 5 percent hydrogen co-firing at the 485–MW combined cycle plant on a GE HA-class (GE 7HA.02) in 2022." 88 *Fed. Reg.* at 33,364.

hydrogen," *Id.* at 9 (emphasis added); (6) notes that Entergy's Orange County Advanced Power Station "*will be* ready to co-fire 30 percent hydrogen by volume at initial operation," *Id.* (emphasis added) despite the fact that the fuel itself may not actually be available; (7) explains that the Magnolia Power Plant "*is expected* to begin operations in 2025 with a GE 7HA.03 combustion turbine . . . [that] *will be* hydrogen-ready with the ability to co-fire up to 50 percent hydrogen by volume *as the fuel becomes available*," 88 *Fed. Reg.* at Hydrogen TSD at 9 (emphasis added); (8) lists Georgia Power's hydrogen blend *test run* at its McDonough Atkinson plant among "demonstrations of existing units co-firing hydrogen;" 88 *Fed. Reg.* at Hydrogen TSD at 9 (emphasis added); (9) describes the New York Power Authority's work at the Brentwood power plant as having "successfully *demonstrated* the ability to co-fire 44 percent 'carbon-free' hydrogen," *Id.* at 10 (emphasis added); (10) explains that the Cricket Valley Energy Center "*is planning* to demonstrate co-firing a 5 percent blend of hydrogen at a combined cycle facility." *Id.* (emphasis added). In addition, these projects generally are running anywhere from a few hours to a few days at the maximum, and none are in continuous commercial operation.[87]

[87] *See, e.g.,* Chemnick, J., EPA extends comment period on landmark power plant rules, E&E GreenWire (June 15, 2023) ("Standards are based on carbon capture and storage and hydrogen co-firing at gas plants, technologies not currently deployed at commercial power plants in the U.S."), https://subscriber.politicopro.com/article/eenews/2023/06/15/epa-extends-comment-period-on-landmark-power-plant-rules-00102152. EPA also overstates projects' hydrogen blending goals. For example, in the Hydrogen TSD, EPA states that the Lincoln Land Energy Center Project will have "the capability to utilize 100 percent low-GHG hydrogen by 2045." 88 *Fed. Reg.* at Hydrogen TSD at 9. However, it is unclear how EPA arrived at 2045. The website that EPA cites references the project's blend "subsequently ris[ing] to 100% *throughout the lifetime of the facility*." Cukia, M., Proposed 1.1GW Lincoln Land Energy Center Project in Illinois Approved, Constructionreview (Aug. 15, 2022), https://constructionreviewonline.com/news/proposed-1-1gw-lincoln-land-energy-center-project-in-illinois-approved/. EmberClear, the project developer, is even more ambiguous about the timing of reaching 100 percent hydrogen firing and explains that the facility "will incorporate the ability to use . . . *up to 100% within the lifespan of this project*." EmberClear, Lincoln Land: Discover What the Lincoln-Land Project is About, https://emberclear.com/lincoln-land/.

A closer look further proves that power sector hydrogen blending is in the pilot and demonstration phase and that these projects are insufficient to support EPA's proposed adequate demonstration determination. For example, the Long Ridge Energy Terminal is testing a 5 percent hydrogen blend in phase one and plans to scale up to a 20 percent hydrogen blend in phase two. The project has explained that operating data from phase one would "validate the design and operating parameters" and allow the developers to "gather information that can be used in the next phases of the hydrogen blending program at Long Ridge and, in GE's case, elsewhere in the engine fleet."[88] This project does not currently serve customers and is seeking to "use successful testing as proof of concept to attract commercial customer(s) for this power."[89]

Similarly, in its discussion of the demonstration project at the Brentwood power plant, the Electric Power Research Institute (EPRI) noted several key findings and operational lessons learned. A review of these key findings and operational lessons learned demonstrates the early phase of hydrogen co-firing in the U.S. power sector. This is underscored by the "next steps" noted in the report, which provide "[l]essons learned during the design and execution of the project are documented in this report, along with recommendations for future LM6000 hydrogen cofiring *investigations*. Researchers will take this information into account in building a foundational knowledge base and *exploring future hydrogen blending pilot projects* as part of the

[88] First Amendment to Construction Certificate Letter of Notification, Long Ridge Energy Generation Project, Ohio Power Siting Bd., 21-0789-EL-BLN, at 6 (July 23, 2021).

[89] *Id*.

clean energy transition."[90] These statements show that this project is in the early stages of testing hydrogen blending and is not sufficient to support a determination that hydrogen blending in the power sector is adequately demonstrated given where it stands in that phase of development. Further to that point, the team also has noted that "[t]ransitioning to higher concentrations of hydrogen may 'bring a new set of unknowns.'"[91]

ii. Current power sector hydrogen blending projects do not include components of the overall value chain that will be critical to the availability of low-GHG hydrogen blending throughout the power sector.

Current pilot projects also cannot demonstrate the adequacy of the overall value chain that will be necessary for low-GHG hydrogen blending to be available throughout the power sector. More specifically, based on publicly available information, current U.S. projects are either producing hydrogen onsite or trucking the hydrogen to the site.[92] However, onsite production will not be feasible for all end-users, particularly where there are emissions limitations on the hydrogen

[90] Elec. Power Res. Inst., Executive Summary: Hydrogen Cofiring Demonstration at New York Power Authority's Brentwood Site: FE LM6000 Gas Turbine, at 5, https://www.epri.com/research/products/000000003002025166 (emphasis added).
[91] Patel, S., Harnessing an H-Class for Hydrogen: Long Ridge Energy Terminal, POWER Mag. (Oct. 2, 2022), https://www.powermag.com/harnessing-an-h-class-for-hydrogen-long-ridge-energy-terminal/.

[92] For example, the hydrogen supply for phase one of the Long Ridge Energy Terminal's testing was planned through "a continuous process with approximately four to five trailers on site at any time: two trailers connected to the offloading manifold, two staged in waiting, and the fifth trailer in transit nearby." OPSB Staff Report of Investigation, Ohio Power Siting Bd., 21-0789-EL-BLN, at 2 (Aug. 13, 2021). Each hydrogen tube trailer would provide approximately 40 minutes to one hour of operational supply. *Id.* at 2. For phase two, the project plans to "transition[] to an on-site, third-party sponsored technology for hydrogen supply, [and that the] hydrogen will be delivered to the Project at a flange connection to be located near the proposed trailer offloading connection and transferred to the fuel blending skid(s) via underground piping." First Amendment to Construction Certificate Letter of Notification, Long Ridge Energy Generation Project, Ohio Power Siting Bd., 21-0789-EL-BLN, at 8 (July 23, 2021).

production pathway as the resources necessary for production (e.g., water and qualifying renewable electricity) are not abundant, available, or feasible in all regions.[93] Where onsite production is not possible, midstream transportation will be necessary.

As discussed below, current projects' onsite production and hydrogen trucking are evidence of the specific lack of midstream infrastructure. Onsite production and trucking are not expected to be feasible for growing sectors. As DOE explains "[i]nitial large-scale deployments of clean hydrogen are expected to target industries *with established supply chains* and economies of scale, such as ammonia production and the petrochemical industry. These deployments will be supplemented with smaller-scale deployments in new applications and growing sectors *as the infrastructure develops*."[94] It is also not clear whether the trucked hydrogen would meet EPA's "low-GHG" requirements, either.

Consequently, while current hydrogen blending projects and plans in the power sector are promising, these projects are only in the early stages of development and are too premature to

[93] It also has been noted that the Long Ridge Energy Terminal is extremely well-situated. Mike Jacoby, President of Ohio Southeast Economic Development recently explained that "Long Ridge Energy Terminal has a unique site with amazing transportation infrastructure and a supply of reliable, competitively priced electricity." Press Release, Long Ridge Energy Terminal Developing Data Center Campus in Hannibal, Ohio, Ohio Southeast Economic Development (Sept. 15, 2021), https://ohiose.com/news/long-ridge-energy-terminal-developing-data-center-campus-in-hannibal-ohio/. Jacoby also notes that the project is located in an Opportunity Zone, which is an area that may be eligible for preferential tax treatment. *See* Internal Revenue Serv., Opportunity Zones Frequently Asked Questions, https://www.irs.gov/credits-deductions/opportunity-zones-frequently-asked-questions.

[94] DOE, U.S. Clean Hydrogen Strategy and Roadmap at 21 (June 2023), https://www.hydrogen.energy.gov/clean-hydrogen-strategy-roadmap.html (emphasis added). *See also* midstream infrastructure discussion *infra.*

support a determination that low-GHG hydrogen co-firing is the BSER. In addition, these projects do not include the midstream infrastructure that will be necessary to ensure low-GHG hydrogen is available throughout the industry. Accordingly, while these projects may mature to the deployment phase and ultimately serve as useful data points for future EPA rulemaking, at present they are insufficient to satisfy section 111's requirements.

b. Current turbine technology to blend hydrogen in the power sector alone is insufficient to support EPA's proposed adequately demonstrated determinations.

EPA notes that turbines have demonstrated a 20-30 percent hydrogen blend with natural gas and that turbine manufacturers are working towards 100 percent hydrogen firing by 2030. 88 *Fed. Reg.* at 33,255 and 33,305. As discussed above, power sector hydrogen blending projects are in the pilot stage and have not been deployed in commercial operation. While turbine capability is advancing, and both turbine manufacturers and EEI's member companies are actively working to deploy these technologies, turbines are only one piece of the puzzle for demonstrating hydrogen blending. As discussed above, power sector hydrogen blending projects are in the pilot stage and have not been deployed in commercial operation. As noted, the power sector is the *only* source category with a public service obligation to operate. Combined cycle and combustion turbines play an essential role in continuing the clean energy transition by providing 24/7 and quick start power, which allows for increased renewable integration and reliable power at affordable rates for customers. As a result, the full operability of *all* elements of the technology system is vital for EGUs, given the power sector's unique obligation to be available and on call to provide power whenever it is needed. However, various elements of the overall value chain that will be needed to support reliable commercial deployment of hydrogen blending across the power sector are still developing.

For example, while GE's 7HA.02 combustion turbine is "'innately capable' of burning 15% to 20% hydrogen by volume . . . [c]rucial to this effort . . . are aligning the differences in the combustion properties of hydrogen and natural gas, as well as impacts to all gas turbine systems, and to the overall balance of plant."[95] Speaking about the Long Ridge Energy Terminal, Director of Emergent Technologies at GE Gas Power's Decarbonization Division, Jeff Goldmeer, further explained that "[t]he 7HA.02 at Long Ridge has not been modified for hydrogen. When we talk about going to 50% or 100% hydrogen, then we'll start needing to see changes in the combustion system, primarily on the gas turbine, and changes in the balance of plant to handle much more hydrogen."[96] In discussing the transition to 100 percent hydrogen by volume, Goldmeer explained that the timing will be driven by several factors—"[t]here are three pieces there, there's the technology readiness, the supply chain component, and then, when it makes sense for the customer to do so."[97]

Moreover, among its operational lessons learned for the Brentwood project, EPRI notes the importance of maintaining a stable supply of hydrogen, "which is critical to transitions of the hydrogen ratio and load of the turbine" and because "[i]nstability of the hydrogen supply could

[95] Patel, S., First Hydrogen Burn at Long Ridge HA-Class Gas Turbine Marks Triumph for GE, POWER Mag. (Apr. 22, 2022) (quoting Jeff Goldmeer, Director of Emergent Technologies at GE Gas Power's Decarbonization Division), https://www.powermag.com/first-hydrogen-burn-at-long-ridge-ha-class-gas-turbine-marks-triumph-for-ge/.

[96] *Id*.

[97] *Id*.

cause the hydrogen system to trip off."[98] Ensuring a stable supply will require either onsite hydrogen production and storage or hydrogen transportation and storage. As noted and further discussed below, co-locating hydrogen production with electric generation, particularly for low-GHG hydrogen production, likely will not be feasible for all entities. This is due to both potential physical space constraints, as well as the lack of access to the resources necessary to produce hydrogen onsite across the power sector. In addition, there are barriers at present to scaling up low-GHG hydrogen production, water availability, pipeline transportation, and storage, and potential cost barriers to hydrogen trucking.

While government and industry are working to overcome these challenges, it is unclear when and to what extent they will be surmounted and what the impact will be on the development of a U.S. clean hydrogen economy that could support reliable and affordable hydrogen co-firing in the power sector. As a result, while EEI and its members are hopeful that the U.S. clean hydrogen economy develops in line with the picture that EPA paints and are actively working to develop it, the Agency's analysis of the demonstrated nature of the technology is overstated and insufficient to support its proposed determinations, and not supported by existing case law.

c. EPA's proposed low-GHG hydrogen production conclusions are based on an insufficient record and low-GHG hydrogen production faces challenges that could limit achievability throughout the industry.

EPA proposes to conclude that the power sector is "likely to have ample access to low-GHG hydrogen and [that it will be] in sufficient quantities to support 30 percent co-firing by 2032 and

[98] Elec. Power Res. Inst., Executive Summary: Hydrogen Cofiring Demonstration at New York Power Authority's Brentwood Site: FE LM6000 Gas Turbine, at 3, https://www.epri.com/research/products/000000003002025166.

96 percent by 2038." 88 *Fed. Reg.* at 33,309. However, as discussed below, EPA's proposed conclusion and the record it has compiled contains errors, overgeneralizations, and a failure to recognize key facts about low-GHG hydrogen production. In addition, section 111 requires EPA to take cost and other factors into consideration in reaching an adequate demonstration determination. However, in the Proposed 111 Rules, the Agency fails to consider how market dynamics and the contours of the U.S. Department of Treasury's (Treasury's) forthcoming guidance on the hydrogen production tax credit (PTC) in the Inflation Reduction Act (IRA) could impact low-GHG hydrogen production and its proposed adequate demonstration determinations.

Moreover, the Proposed 111 Rules and the record compiled by EPA also include several contradictory statements. For example, EPA states that "[w]hether there will be sufficient volumes of low-GHG hydrogen for new sources to co-fire [in line with EPA's proposal] will depend on the deployment of additional low-GHG electric generation sources, the growth of electrolyzer capacity, and market demand." *Id.* EPA also "recogniz[es] that there are likely limits to the clean hydrogen supply in the mid-term." 88 *Fed. Reg.* at 33,362. EPA does not attempt to square these statements with its proposed determination.

For these reasons, EPA's proposed determination is not the product of reasoned decision making as its record casts doubt on The Agency's conclusions, and also lacks key information. When included, the information that EPA fails to analyze shows the Agency's proposed determinations are unsupported.

i. EPA's existing record is mischaracterized and overgeneralized, and closer investigation reveals the record does not support the proposed adequate demonstration determinations.

EPA's discussion includes overgeneralizations and misstatements that it significantly relies upon for its proposed determinations. For example, EPA notes that "[p]rograms from the IIJA and IRA have been successful in promoting the development of new low-GHG hydrogen projects and infrastructure. As of August 2022, *374 new projects* had been announced that would produce 2.2 megatons (Mt) of *low-GHG hydrogen* annually, which represents a 21 percent increase over current output." 88 *Fed. Reg.* at 33,312 (citing Energy Futures Initiative, U.S. Hydrogen Demand Action Plan (Feb. 2023), https://energyfuturesinitiative.org/reports/) (emphasis added). EPA cites the Energy Futures Initiative's (EFI's) U.S. Hydrogen Demand Action Plan to support this statement. However, EFI's report actually states that it has "tracked *374 distinct clean hydrogen* project announcements . . . [and a] review of publicly announced projects shows 2.2 million metric tons (megatons [Mt]) *of potential clean hydrogen* supply, or roughly 21 percent of the current U.S. hydrogen industry's output."[99]

EFI's use of the term "clean hydrogen" encompasses multiple production pathways—namely, blue hydrogen (produced from methane reformation with carbon capture), green hydrogen (produced from water using renewable electricity), turquoise hydrogen (produced through methane pyrolysis), and pink hydrogen (produced from water using nuclear electricity).[100] By

[99] Energy Futures Initiative, U.S. Hydrogen Demand Action Plan, at 12 (Feb. 2023), https://energyfuturesinitiative.org/reports/ (emphasis added).

[100] *See, e.g.,* Energy Futures Initiative, U.S. Hydrogen Demand Action Plan, at Figure 4 (Feb. 2023), https://energyfuturesinitiative.org/reports/.

contrast, EPA's proposed definition of low-GHG hydrogen would, at a minimum, not include hydrogen produced from methane reformation with carbon capture. EPA explains that whether methane pyrolysis qualifies as low-GHG hydrogen depends on "the source of the energy used to decompose the methane." 88 *Fed. Reg.* at n.397. Further, depending on the contours of Treasury's hydrogen PTC guidance and the extent to which EPA's final rule aligns with that guidance, EPA's definition of low-GHG hydrogen also may not include hydrogen produced using nuclear electricity, as discussed *infra*. If methane pyrolysis and production using nuclear power are included, less than 0.2 MMT of the 2.2 MMT of clean hydrogen production projects noted in EFI's report would qualify as low-GHG hydrogen production under EPA's proposed definition—without these two pathways, the total is less than 0.15 MMT of the 2.2 MMT projects that EFI discusses and that EPA attempts to attribute to low-GHG hydrogen.[101] Stated differently, at maximum, less than 10 percent of the announced clean hydrogen production projects noted in EFI's report would qualify as low-GHG hydrogen production under EPA's proposal.

Importantly, EFI also explains that while "around 70 percent of the recently announced projects involve green hydrogen," this interest "may not be immediately effective for scaling regional clean hydrogen markets."[102] Moreover, "[d]espite representing a relatively small share of the total, blue hydrogen projects account for nearly 95 percent of the capacity of announced projects."[103] The difference between EPA's own proposed definition and EFI's use of the term

[101] *See id*.

[102] *See id*., at 29 (Feb. 2023), https://energyfuturesinitiative.org/reports/.

[103] *Id*.

clean hydrogen is significant but the Agency does not discuss EFI's actual findings with respect to low-GHG hydrogen production and their implications for EPA's proposed determinations.

ii. Low-GHG hydrogen production faces challenges that could limit achievability throughout the industry.

At present, the United States produces approximately 10 MMT per year of hydrogen, the majority of which is produced from natural gas or coal without carbon capture technology. DOE estimates that "[c]lean hydrogen production for domestic demand has the potential to scale from < 1 million metric tons per year (MMTpa) to ~10 MMTpa in 2030."[104] It is important to note that DOE's estimates are of "clean" hydrogen, which DOE defines as having a carbon intensity of less than 4 kg CO_2e/kg of hydrogen on a lifecycle basis measured from well-to-gate.[105] This is in contrast to EPA's "low-GHG" hydrogen, which it proposes to define as having a carbon intensity less than or equal to 0.45 kg CO_2e/kg of hydrogen on a lifecycle basis measured from well-to-gate. 88 *Fed. Reg.* at 33,304. As noted above, the most salient production pathway to qualify under EPA's definition is through electrolysis powered by renewable electricity.[106]

[104] Clean Hydrogen Liftoff Report at 1.

[105] U.S. Dep't of Energy Clean Hydrogen Production Standard (CHPS) Guidance, https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-production-standard-guidance.pdf; and Clean Hydrogen Liftoff Report at n.1.

[106] In light of EPA's proposal to require the use of low-GHG hydrogen, the discussion below focuses on electrolytic hydrogen produced using clean electricity. However, other production pathways, which may be necessary to support the level of deployment that would be required to comply with the Proposed 111 Rules, similarly face barriers to scaling up. As noted, while entities across government agencies and industry are working to overcome these challenges, it is unclear at this point when, how, and to what extent and what the impacts will be on availability of low-GHG hydrogen.

There are several challenges to scaling production of EPA's low-GHG hydrogen, including the need to increase electrolyzer manufacturing and resolve related supply chain challenges, as well as access to clean electricity. As DOE explains in the Clean Hydrogen Liftoff Report, "[e]lectrolysis will be challenged by supply-chain constraints in both raw materials and equipment manufacturing capacity during a critical scale-up period through 2025 in addition to challenges with renewables build-out and sourcing a domestic workforce."[107] Importantly, DOE further notes that "[i]f electrolysis fails to scale during the PTC time horizon, it may not achieve sufficient cost downs prior to PTC expiration."[108] While EPA makes mention of some of the issues discussed below, the Proposed 111 Rules do not include adequate discussion or analysis of these issues and it does not appear that EPA has taken them into account in reaching its proposed determinations.

1. EPA does not adequately analyze the need for domestic electrolyzer manufacturing capacity to scale up exponentially, which could impact low-GHG hydrogen production and limit achievability throughout the industry.

It is well-recognized that increased electrolyzer manufacturing will be a necessary component to development of a hydrogen market at scale. In a 2022 report, the International Energy Agency explained that Europe and China account for 80 percent of global manufacturing capacity.[109] As countries around the world, including the United States, look to significantly increase hydrogen production to help meet their climate goals, there is a corresponding need to ramp up electrolyzer manufacturing capacity.

[107] Clean Hydrogen Liftoff Report at 45.

[108] Clean Hydrogen Liftoff Report at 45.

[109] Int'l Energy Agency, Electrolyzers (Sept. 2022), https://www.iea.org/reports/electrolysers.

In the United States, there are "only a few small-scale electrolyzer manufacturers."[110] Meeting DOE's projected demand, which EPA repeatedly references, and avoiding "an electrolyzer bottleneck" will require a "rapid and significant ramp-up in capacity."[111] DOE explains that

> [t]o enable deployment of ~100 GW of operational electrolyzers by 2030, domestic production would need to scale from 4 GW of publicly announced capacity with target commercial operation dates (CODs) to as much as ~20–25 GW p.a. by 2030. In some instances, hydrogen producers today are already being quoted lead times of 2 to 3 years when they order electrolyzers. If the size of U.S. production facilities increases to match EU facility sizes, the U.S. could require as much as ~12–14 additional electrolyzer production facilities by 2030.[112]

The scope of the challenge of achieving this goal also is evident from the inclusion of electrolyzers in President Biden's June 6, 2022, presidential determinations under the Defense Production Act.[113]

Despite this significant and well-known potential barrier, the Proposed 111 Rules do not substantively address the need for "growth of electrolyzer capacity" and only include a high-level description of three electrolyzer factories that are "under development" in the United States. 88 *Fed. Reg.* at 33,309 and Hydrogen TSD at 23. Adequate access to electrolyzers is

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[110] Clean Hydrogen Liftoff Report at 87.

[111] *Id*. at 87.

[112] *Id*. at 46.

[113] *Memorandum on Presidential Determination Pursuant to Section 303 of the Defense Production Act of 1950, as amended, on Electrolyzers, Fuel Cells, and Platinum Group Metals* (June 6, 2022), https://www.whitehouse.gov/briefing-room/presidential-actions/2022/06/06/memorandum-on-presidential-determination-pursuant-to-section-303-of-the-defense-production-act-of-1950-as-amended-on-electrolyzers-fuel-cells-and-platinum-group-metals/.

critical to scaling the U.S. clean hydrogen economy and to the power sector's ability to deploy hydrogen blending. EPA's failure to analyze the potential barriers that electrolyzer manufacturing faces are a significant flaw in its record and undermine its proposed adequate demonstration determination. Critically, these are flaws that providing significant "lead time" alone cannot heal since the underlying issues must be actively resolved and not passively solved through the lapse of time.

2. EPA does not adequately analyze supply constraints for the raw materials required for electrolyzer production that could impact low-GHG hydrogen production and limit achievability throughout the industry.

Even if the United States is able to scale up its electrolyzer manufacturing capacity, access to the raw materials required to manufacture electrolyzers are anticipated to become constrained. DOE explains that "[w]hile global raw material shortages are not currently an issue, the global abundance of certain materials, particularly platinum group metals (PGMs), may be stressed by electrolyzer production in 2030 and beyond."[114] This concern also is underscored by the inclusion of PGMs in President Biden's June 6, 2022, presidential determinations under the Defense Production Act.[115]

[114] Clean Hydrogen Liftoff Report at 88.

[115] *Memorandum on Presidential Determination Pursuant to Section 303 of the Defense Production Act of 1950, as amended, on Electrolyzers, Fuel Cells, and Platinum Group Metals* (June 6, 2022), https://www.whitehouse.gov/briefing-room/presidential-actions/2022/06/06/memorandum-on-presidential-determination-pursuant-to-section-303-of-the-defense-production-act-of-1950-as-amended-on-electrolyzers-fuel-cells-and-platinum-group-metals/.

Although several types of electrolyzers technologies are being explored and developed, the two technologies that are beyond the laboratory phase and at the commercial stage of maturity are alkaline water electrolysis and proton exchange membranes (PEM).[116] Alkaline electrolyzers are the dominant technology at present. These electrolyzers require nickel, which, in scaling up "may face higher costs from material constraints [as it is] widely used in other expanding industries."[117]

Alkaline electrolyzers are not highly flexible and are large. As a result, there has been significant interest in PEM electrolyzers, which have "a fast response ramp-up and ramp-down capability, as well as a wide dynamic operating range of 0-100%."[118] However, PEM electrolyzers also face a potential raw materials challenge as they require iridium, for which there is no significant domestic source.[119] In the Clean Hydrogen Liftoff Report, DOE explains that by 2030, U.S. demand for PEM electrolyzers could require approximately 15-30 percent of the global production of iridium raw material.[120] DOE also notes that its forecast for iridium demand assumes that PEM electrolyzers will have a 25 percent market share and that this "likely represents a conservative assumption" as other analyses show an approximately 30 percent

[116] Clean Hydrogen Liftoff Report at Figure 3. *See also* Int'l Energy Agency, Hydrogen Supply (Sept. 2022), https://www.iea.org/reports/hydrogen-supply.

[117] Clean Hydrogen Liftoff Report at 59.

[118] Cockerill, R., *Electrolyser Technologies: PEM vs Alkaline Electrolysis,* H2VIEW (Nov. 2020), https://nelhydrogen.com/wp-content/uploads/2021/07/Alk-vs-PEM.pdf.

[119] Clean Hydrogen Liftoff Report at 59. *See also id.* at 46 (explaining that "[o]ver 80% of iridium supply comes from South Africa, with almost no opportunity for domestic production").

[120] *Id*. at 45.

global market share.[121] DOE notes that "[n]onetheless, the quantity of iridium required is significant."[122] Requirements to satisfy projected PEM electrolyzer production could, in fact, exceed the quantity of iridium that is economically feasible to mine,[123] as "iridium deposits are limited and only mined on a small scale."[124]

DOE also explains that U.S. electrolyzer manufacturers will need graphite, yttrium, platinum, and strontium, "most of which cannot be found domestically in sufficient quantities [and] reliance on foreign suppliers could hinder growth of U.S. based electrolyzer manufacturing."[125]

As noted *supra*, EPA does not discuss these potential supply chain concerns in the Proposed 111 Rules and does not appear to have taken these issues into consideration in its analysis, which the Agency must do as part of determining BSER. EPA's failure to analyze the potential barriers that electrolyzer manufacturing faces is a significant flaw in its record and undermine its proposed determination that hydrogen blending is adequately demonstrated.

3. EPA does not adequately analyze the need to significantly increase clean electricity production and accessibility that could impact low-GHG hydrogen production and achievability throughout the industry.

[121] *Id*. at 87.

[122] *Id*.

[123] *Id*. at 59.

[124] *Id*. at 87.

[125] *Id*. at 88.

In addition to the criticality of scaling up electrolyzer manufacturing and production, access to clean electricity is key to low-GHG hydrogen production.[126] As noted, EPA proposes to require that the hydrogen co-firing pathway utilize low-GHG hydrogen, which will require the use of clean electricity, like wind and solar. In the Clean Hydrogen Liftoff Report, DOE explains that "[f]or water electrolysis, availability of clean electricity . . . will play a critical role in the pace of growth."[127] DOE further projects that, by 2030, electrolytic hydrogen production could require up to 200 gigawatts (GW) of additional renewables. In addition to potential siting and permitting challenges, this scale of build-out implicates non-air impacts associated with land-use, as discussed below.

Further, while the share of wind and solar generation is increasing,[128] demand for clean electricity also is accelerating. This presents "a challenge across many clean energy technologies

[126] Electrolysis is inherently reliant on access to water. DOE estimates that "10 MMT [of] hydrogen produced from water electrolysis would require 29 billion gallons of water." Clean Hydrogen Liftoff Report at endnote viii. However, access and the legal rights to use water vary in the United States. For example, in many states in the West where water is constrained, the governing legal regimes generally are restrictive and require water rights or permits for most uses. *See, e.g.,* Water Resource Considerations for the Hydrogen Economy, K&L Gates LLP (Dec. 16, 2020), https://www.klgates.com/Water-Resource-Considerations-for-the-Hydrogen-Economy-12-16-2020. These regimes often also include senior and junior water rights based on when the rights were obtained. During droughts, senior right holders take precedence over junior holders. These access issues may create challenges for low-GHG hydrogen production in certain regions of the United States. EPA does not discuss these potential supply issues in the Proposed 111 Rules and does not appear to have taken these issues into consideration in its analysis.

[127] Clean Hydrogen Liftoff Report at 3.

[128] The mix of resources used to generate electricity in the United States has changed dramatically over the last decade and is increasingly cleaner. *See* U.S. Energy Information Administration (EIA), Today in Energy: Renewable generation surpassed coal and nuclear in the U.S. electric power sector in 2022 (Mar. 27, 2023), https://www.eia.gov/todayinenergy/detail.php?id=55960&src=email; *See also* EIA, Electric Power Monthly: Data for February 2023—Table 1.1 Net Generation by Energy Source: Total (All Sectors), 2013-February 2023 (Mar. 24, 2023),

as new electricity demand (e.g., for electrolysis, direct air capture) develops in parallel to electrification of buildings and transport."[129] Critically for the purposes of EPA's proposed determination, constraints in renewables development could impact how hydrogen production develops.[130]

DOE notes that using nuclear power to produce hydrogen could relieve some of this pressure.[131] However, it is not clear whether electricity from nuclear generation will qualify under EPA's definition of low-GHG hydrogen. More specifically, EPA proposes to align its definition of low-GHG hydrogen with Treasury's forthcoming hydrogen PTC guidance. 88 *Fed. Reg.* at 33,330. The contours of this Treasury guidance have been hotly debated, including whether Treasury should impose additionality requirements. *See, e.g., id.* at 33,330-31. Such requirements could disqualify electricity from existing nuclear generation. If Treasury imposes an additionality requirement that would disqualify existing nuclear and EPA incorporates this principle into the

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https://www.eia.gov/electricity/monthly/xls/table_1_01.xlsx; *and* EIA, Electric Power Monthly: Data for February 2023—Table 1.1.A. Net Generation from Renewable Sources: Total (All Sectors) (Mar. 24, 2023), https://www.eia.gov/electricity/monthly/xls/table_1_01_a.xlsx. In 2022, for the first time, renewable energy sources surpassed coal as a fuel: 22.6 percent of total generation at utility scale facilities in the United States came from renewable sources compared to 19 percent from coal-based generation. *See* EIA, Electric Power Monthly, Table 1.1. In total, more than 40 percent of America's electricity came from clean carbon-free resources in 2022, including nuclear energy, hydropower, solar, and wind, putting clean resources at parity with natural gas generation, which provided approximately 40 percent of the country's total electricity generation at utility scale facilities in 2022. *See id.*

[129] Clean Hydrogen Liftoff Report at 59.

[130] *See, e.g., id*. at 37 ("If clean electricity deployment is constrained by challenges such as land use restrictions or siting/permitting bottlenecks, modeling results show reformation with CCS will dominate.").

[131] *Id*. at 59.

final rule, the challenges in accessing sufficient clean electricity to meet power sector demands under the Proposed 111 Rules, noted above, will likely be exacerbated.

The transmission grid itself also is in the midst of significant change. It is estimated that the capacity of the existing grid must increase by as much as 60 percent by 2030, and it may need to triple in size by 2050 to meet the growing demand for clean electricity to support a carbon-free economy.[132] Transmission is a key enabling technology for the clean energy transition because it allows interconnection of new resources and better utilization of both new and existing resources, including reduced curtailment of wind and solar energy. Large-scale regional and interregional transmission can enhance reliability by expanding electricity imports and exports and by improving coordination across wider geographies. Expanding the grid will require siting and construction of additional transmission infrastructure.

At present, there are several ongoing regulatory reform efforts in areas central to grid function. For example, the Federal Energy Regulatory Commission (FERC) recently issued a proposed rulemaking regarding Applications for Permits to Site Interstate Electric Transmission Facilities (commonly referred to as FERC's "backstop authority"),[133] and solicited comments in response to a Staff-led workshop regarding the possibility of a minimum requirement for Interregional

[132] *See* Eric Larson et al., Net-Zero America by 2050: Potential Pathways, Infrastructure, and Impacts, Final Report Summary, at 76 (Princeton University, Oct. 29 2021), https://netzeroamerica.princeton.edu/img/Princeton%20NZA%20FINAL%20REPORT%20SUMMARY%20(29Oct2021).pdf.

[133] *Applications for Permits to Site Interstate Electric Transmission Facilities*, 181 FERC ¶ 61,205 (2022).

Transfer Capability for public utility transmission providers in transmission planning and cost allocation processes.[134] Furthermore, as a result of the current significant backlog in the queue of projects waiting to connect to the grid concerns,[135] FERC recently issued an order seeking to resolve the interconnection backlog.[136] As of the time of this filing, the opportunity to request rehearing on that order remains open and it appears likely that such requests will be filed, which could result in modification of FERC's order. The outcome of these proceedings could significantly change the pace of development of the grid and access to clean electricity.

As discussed above, EPA does not discuss these potential supply issues—issues principally out of the control of the owner/operators of the affected sources regulated by EPA—in the Proposed 111 Rules and does not appear to have taken these issues into consideration in its analysis. Access to clean electricity—and also the water resources needed for electrolysis—is critical to scaling the U.S. clean hydrogen economy and to the power sector's ability to deploy hydrogen blending. EPA's failure to analyze the potential barriers to scaling clean electricity generation and access are a significant flaw in its record and undermine its proposed adequate demonstration determination.

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[134] Notice Requesting Post-Workshop Comment, Docket No. AD23-3-000 (filed Feb. 28, 2023).

[135] DOE has reported more than 930 gigawatts (GW) of solar, wind, hydropower, geothermal, and nuclear capacity currently are in interconnection queues seeking transmission access, as are more than 420 GW of energy storage. U.S. Dep't of Energy, Queued Up…But in Need of Transmission: Unleashing the Benefits of Clean Power with Grid Infrastructure (Apr. 2022), https://www.energy.gov/sites/default/files/2022-04/Queued%20Up%E2%80%A6But%20in%20Need%20of%20Transmission.pdf. FERC has noted that "interconnection queue backlogs and study delays afflicting generator interconnection service nationwide hinder the timely development of new generation." *Improvements to Generator Interconnection Procedures and Agreements*, 179 FERC ¶ 61,194, P 22 (2022).

[136] *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 (2023).

iii. EPA does not adequately analyze critical market dynamics that could impact low-GHG hydrogen production and achievability throughout the industry.

As noted, section 111 requires EPA to take cost into consideration in its BSER determinations. In the Clean Hydrogen Liftoff Report, DOE notes several potential challenges related to market dynamics that could impact the availability of low-GHG hydrogen on the timelines that EPA projects and which EPA does not recognize or adequately analyze. These include the potential that, in the period while the challenges facing hydrogen liftoff are being resolved, there will be high perceived credit risk for hydrogen projects that will "delay[] timelines for low-cost capital providers to enter the market."[137] In addition, "[s]ome offtakers worry that, until hydrogen production scales nationally, hydrogen supplies will be insufficient and/or too variable to meet high uptime use cases. For example, if stock-outs such as those that have been experienced at refueling stations in California were to become widespread, the industry would face additional headwinds to wider adoption."[138]

It is also unclear how many of the currently announced projects will reach final investment decision (FID). In the Clean Hydrogen Liftoff Report, DOE emphasizes the current lack of long-term offtake agreements, which likely is a function of the other barriers discussed herein. These agreements are a necessary component for many projects to reach FID. While there are currently over 100 clean hydrogen production projects that, if built, would meet DOE's 2030 clean hydrogen demand projections, "[o]nly ~1.5 MMT of this announced capacity has reach final

[137] Clean Hydrogen Liftoff Report at 3.

[138] *Id*. at 57.

investment decision."[139] Importantly for EPA's low-GHG hydrogen proposal, of the announced projects "43% are electrolytic and 56% are reformation based."[140] DOE notes that "[p]roject trackers vary the way in which they log announced capacity," and explains EFI's findings, noted above. More specifically, DOE cites EFI's statement that while green hydrogen production projects account for around 70 percent of recently announced projects, "blue hydrogen projects account for nearly 95 percent of the capacity of the announced projects" and green hydrogen projects are "a relatively small share" by contrast.[141] Consequently, while there is reason to be optimistic about the scale up of U.S. clean hydrogen production capacity, the contours, timing, and size of this capacity are evolving and remain unsettled at present despite the significant efforts by DOE and industry to attempt to make this scaling up a reality.

In addition, EPA correctly notes that DOE's estimate of the potential for 10 MMT of clean hydrogen production capacity by 2030 (1) includes a wider range of hydrogen production pathways than would qualify under EPA's definition because DOE defines "clean" hydrogen to be less than 4 kg CO_2e/kg of hydrogen—as discussed in greater detail *infra*, EPA should adopt an inclusive definition of qualifying hydrogen than its current proposal to enable scale up of the U.S. clean hydrogen market and to reflect the variability of production resources across the country and electric sector; and (2) does not include significant anticipated power sector demand. While EPA may be correct that the Proposed 111 Rules will increase demand for low-GHG hydrogen beyond DOE's projections, given midstream barriers, such demand increases not only

[139] *Id*. at 23.

[140] *Id*. at n.67.

[141] *Id*. at 23 (citing Energy Futures Initiative, U.S. Hydrogen Demand Action Plan (Feb. 2023), https://energyfuturesinitiative.org/reports/).

do not necessarily result in corresponding access to low-GHG hydrogen but also have the potential to exacerbate the challenges facing the scale up of low-GHG hydrogen production discussed above. 88 *Fed. Reg.* at 33,309 ("The EPA's hydrogen co-firing BSER proposal, if finalized, would create a significant additional demand driver for electrolytic hydrogen not considered in the DOE's hydrogen production goals of 10 MMT by 2030 and 20 MMT by 2040."). As a result, despite EPA's optimism around the potential impacts of the proposed rule, the actual outcome of its determination that hydrogen blending is BSER may be counterproductive to the development of the U.S. clean hydrogen economy that will be needed to support reliable and affordable hydrogen co-firing in the power sector despite the significant efforts underway to develop this economy by DOE and industry. The level of uncertainty alone shows that EPA's proposed determinations are not consistent with a conclusion that low-GHG hydrogen blending in the power sector has been adequately demonstrated.

iv. EPA fails to adequately analyze how Treasury guidance on the hydrogen PTC could impact low-GHG hydrogen production and achievability throughout the industry.

EPA states that the hydrogen PTC has the potential to drive great volumes of electrolytic hydrogen demand. *Id.* However, as DOE notes,

> [i]mplementation details for the hydrogen PTC are forthcoming from IRS and Treasury. Until there is additional clarity, there will be uncertainty about which projects will qualify and what prices producers will have to charge to break-even. The inability to project future revenues can be a hurdle to securing financing for low carbon intensity hydrogen production projects while 45V implementation policy remains under development.[142]

In addition, as noted above, the details of Treasury's guidance may constrict the resources that project developers can use to qualify for the PTC, potentially exacerbating and elongating the

[142] *Id*. at 57.

timeline to resolve existing challenges. Further, while the production tax credits under the IRA are designed to ease the challenges currently facing scale up of a U.S. clean hydrogen economy, EPA cannot use the existence of these credits to support a conclusion that the "low-GHG" hydrogen production pathway is the BSER. EPA does not discuss these issues or appear to have taken them into account in its proposed determinations. It should do so in any final rulemaking.

d. EPA's proposed midstream infrastructure conclusions are based on an insufficient record as the Agency fails to consider challenges that could limit achievability throughout the industry.

EPA states that "[g]iven the growth in the hydrogen sector and Federal funding for the H2Hubs, which will explicitly explore and incentivize hydrogen distribution, the EPA therefore believes that hydrogen distribution and storage infrastructure will not present a barrier to access for new combustion turbines opting to co-fire with 30 percent low-GHG hydrogen by volume in 2032 and to co-fire with 96 percent low-GHG hydrogen by volume in 2038." 88 *Fed. Reg.* at 33,309. In reaching this conclusion, EPA discounts the need for midstream infrastructure and fails to adequately consider technical challenges and open regulatory questions facing midstream infrastructure buildout that could limit achievability of low-GHG hydrogen blending throughout the power sector.

i. Despite EPA's assertions, additional midstream infrastructure will be needed to enable the scaling of the U.S. clean hydrogen economy and support achievability throughout the industry.

EPA suggests in its discussion of low-GHG hydrogen costs that significant additional midstream infrastructure will not be needed to support low-GHG hydrogen blending in the power sector. More specifically, EPA notes that the "majority of announced combustion turbine EGU projects proposing to co-fire hydrogen are located close the source of hydrogen. Therefore, the fuel delivery systems (*i.e.,* pipes) for new combustion turbines can be designed to transport hydrogen

without additional costs." *Id.* at 33,314. The fact that most announced projects do not require significant midstream investment does not support EPA's conclusion since many announced projects plan to co-locate with hydrogen production[143] *because of* the current lack of midstream infrastructure.[144] In fact, co-location is a function of the need to build-out this critical component of the value chain rather than proof that it will not be required. This need is even more pronounced for retrofits, which cannot be collocated with new greenfield production since they *already exist elsewhere*.

Indeed, development of the U.S. clean hydrogen markets, which will be necessary to support reliable and affordable low-GHG hydrogen blending in the power sector, will require midstream infrastructure.[145] In fact, midstream infrastructure is one of the main challenges to deployment at scale discussed in DOE's Clean Hydrogen Liftoff Report. DOE explains that

> [p]ipelines and geologic storage are costly upfront to develop, but at high hydrogen volumes provide critical economies of scale. Dedicated hydrogen pipelines and low-cost geologic storage are expected to anchor hydrogen infrastructure in the long-term (post-2035). . .As described throughout this report, in the near-term limited

[143] *See, e.g.,* U.S. Dep't of Energy, U.S. Clean Hydrogen Strategy and Roadmap at 12 (June 2023), https://www.hydrogen.energy.gov/clean-hydrogen-strategy-roadmap.html, ("These initial use-cases are also frequently co-located, meaning they can capitalize on low-cost hydrogen production without incurring midstream distribution/storage costs.").

[144] Clean Hydrogen Liftoff Report at 24 ("*Due to limited midstream infrastructure*, announced hydrogen production projects to date have focused on offtakers that can be co-located with production as well as offtakes that already use carbon-intensive hydrogen.")(emphasis added).

[145] EPA itself appears to recognize this and states in the TSD that "[a] viable hydrogen infrastructure requires that hydrogen be able to be delivered from where it is produced to the point of end use, such as [a] . . . power generator. That infrastructure also must be able to delivered hydrogen to the point of use at the times needed, requiring storage infrastructure." 88 *Fed. Reg.* at Hydrogen TSD at 24. However, it is unclear how this statement squares with EPA's proposed determination noted above.

> availability of midstream infrastructure is a constraint for scaling clean hydrogen where co-located production and offtake is not feasible, representing a key challenge that must be addressed.[146]

Moreover, DOE notes that "[t]he absence of affordable midstream infrastructure risks slowing the hydrogen economy."[147]

EPA's suggestion that significant midstream infrastructure will not be required is incorrect in and of itself and also off base about how the U.S. clean hydrogen economy is expected to evolve.

ii. EPA fails to adequately analyze critical pipeline-related issues that could impact achievability throughout the industry.

In contrast to the nearly three million miles of interstate and intrastate natural gas pipelines in the United States,[148] there are only approximately 1,600 miles of hydrogen pipe.[149] There are two potential methods for transporting hydrogen by pipeline: in existing non-hydrogen pipelines, which will require retrofits; and in new, dedicated hydrogen pipelines. As discussed in greater detail below, each method presents potential challenges that government agencies and industry are working to overcome. These include technical challenges, particularly for existing non-hydrogen pipelines, as well as critical open regulatory questions for interstate transportation of hydrogen by pipeline. Due in part to these issues, it is unclear how quickly pipeline transportation of hydrogen will emerge in the United States.

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[146] Clean Hydrogen Liftoff Report at 14.
[147] *Id*. at 57.

[148] U.S. Energy Info. Admin., Natural Gas Explained: Natural Gas Pipelines, (Dec. 3, 2020), https://www.eia.gov/energyexplained/natural-gas/natural-gas-pipelines.php.

[149] U.S. Dep't of Energy, Hydrogen Pipelines, https://www.energy.gov/eere/fuelcells/hydrogen-pipelines.

EPA discusses several of these challenges in the Hydrogen TSD. However, the Agency does not explain how these challenges impact its proposed determination that midstream "infrastructure will not present a barrier" to power sector low-GHG hydrogen blending under the Proposed 111 Rules. 88 *Fed. Reg.* at 33,314.

1. EPA fails to adequately analyze technical challenges that could impact achievability throughout the industry.

The ability to leverage our nation's existing natural gas pipeline system to transport hydrogen blended with natural gas presents a significant opportunity. While demonstration and pilot projects to test the effects of hydrogen blending in distribution systems have been announced, are underway, or have been recently completed,[150] "blending still faces several technical [ ] barriers."[151]

For example, blending may be limited by physical constraints, including the potential for steel

[150] For example, Dominion Energy's ThermH2 pilot project at its Training Academy in Utah will blend 5 percent hydrogen in a test gas distribution system to gather information for potential blending into its larger system. *Hydrogen: The Next Frontier of Clean Energy*, Dominion Energy, https://www.dominionenergy.com/projects-and-facilities/hydrogen. Southern California Gas and San Diego Gas and Electric announced the creation of the Hydrogen Blending Demonstration Program in November 2020 to "provide an understanding of how to safely incorporate hydrogen, a zero-emission fuel, into the gas grid." Press Release, SoCalGas and SDG&E Announce Groundbreaking Hydrogen Blending Demonstration Program to Help Reduce Carbon Emissions, Southern California Gas (Nov. 23, 2020), https://newsroom.socalgas.com/press-release/socalgas-and-sdge-announce-groundbreaking-hydrogen-blending-demonstration-program-to.

[151] Int'l Energy Agency, Global Hydrogen Review 2021, at 145 (Oct. 2021) https://www.iea.org/reports/global-hydrogen-review-2021. The International Energy Agency further explains that "[p]arameters related to natural gas quality (composition, calorific value and Wobbe index) – as regulated in different countries – can limit (or completely prevent) injection of hydrogen into gas grids. The hydrogen purity requirements of certain end users, including industrial clients, can further constrain blending. In addition, resulting changes in the physical characteristics of the gas can affect certain operations, such as metering." *Id.*

embrittlement. In the United States, steel pipe comprises more than a quarter-million miles of the natural gas transmission system.[152] The International Energy Agency explains that "[d]ue to its chemical properties . . . [hydrogen] can cause embrittlement of steel pipelines, i.e. reactions between hydrogen and steel can create fissures in pipelines."[153] As DOE explains, "hydrogen embrittlement (permeation of hydrogen into steel) can crack steel pipes, leading to leakage or combustion."[154]

EPA makes only passing reference to this in the Proposed 111 Rules. For example, in the Hydrogen TSD, EPA states that "[a] limitation on greater volumes of hydrogen being safely mixed with natural gas in existing natural gas pipelines is the potential embrittlement and weakening of pipes that leads to leakage." 88 *Fed. Reg.* at Hydrogen TSD at 28. In its single reference to embrittlement issues in the preamble, EPA explains that "the material used to construct the piping could need to be specifically designed to be able to handle higher concentrations of hydrogen that would prevent embrittlement and leaks." 88 *Fed. Reg.* at 33,313-14. However, rather than address potential issues for blending in existing pipelines, EPA simply notes that "[t]hese risks can be mitigated through deployment of new pipeline infrastructure designed for compatibility with hydrogen in support of a new combustion turbine installation,"

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[152] *See* Clean Hydrogen Liftoff Report at n.122.

[153] Int'l Energy Agency, Global Hydrogen Review 2021, at 145 (Oct. 2021), https://www.iea.org/reports/global-hydrogen-review-2021. *See also* U.S. Dep't of Energy, Hydrogen Pipelines, https://www.energy.gov/eere/fuelcells/hydrogen-pipelines. The International Energy Agency's Global Hydrogen Review 2021 also points that that "considering that hydrogen has a higher leakage rate and an ignition range about seven times wider than that of methane, it may be necessary to upgrade leak detection and flow control systems." Int'l Energy Agency, Global Hydrogen Review 2021, at 147 (Oct. 2021), https://www.iea.org/reports/global-hydrogen-review-2021.

[154] Clean Hydrogen Liftoff Report at n.122.

88 *Fed. Reg.* at 33,314. *But see id.* at Hydrogen TSD at 25-26 ("The capital costs of new pipeline construction constitute a barrier to expanding hydrogen pipeline delivery infrastructure."), and that "[h]ydrogen blending into existing natural gas pipelines presents another mode of transport and distribution that is actively in use in Hawaii and under exploration in other areas of the country." *Id.* at 33,309. However, EPA fails to account for the challenges to building new pipeline infrastructure, discussed below, as well as distinctions between and across pipeline systems. Moreover, the fact that it *might* be feasible is insufficient to support a BSER determination, as discussed *supra*.

EPA briefly mentions several analyses of potential blend limits in the Hydrogen TSD and correctly notes that "[b]lend limits depend on the design and condition of current pipeline materials (*e.g.,* integrity, dimensions, materials of construction) [and] design and condition of pipeline infrastructure equipment (*e.g.,* compressor stations)." 88 *Fed. Reg.* at Hydrogen TSD at 26. However, EPA also notes "that the concerns relating to natural gas pipeline embrittlement from hydrogen transportation have been disputed," citing to a German paper about pipelines in Germany. *Id.* (citing Wasserstofftransport, Nationaler Wasserstoffrat (2021), https://wasserstoffwirtschaft.sh/file/nwr_wasserstofftransport_web-bf.pdf (In German).) However, this paper explains that "[i]t is known that, under certain conditions, hydrogen can lead to embrittlement of the steel materials commonly used in gas pipelines" and that fracture mechanics analyses, carried out in accordance with ASME B31.126 "have shown that the steels used in the field of natural gas pipelines and plants are *in principle* suitable for use with hydrogen and that the dimensioning and design of the pipeline for use with hydrogen can be

confirmed."[155] As noted above, differences between and across pipeline systems are highly relevant to blend limits and the mere fact that blending in pipelines in Germany does not create embrittlement issues "in principle" is insufficient to justify a conclusion that the same is true throughout the U.S. pipeline system.

EPA also notes that the use of fiber reinforced polymer (FRP) may be a way to protect pipelines from embrittlement. However, EPA explains that "FRP is not authorized by Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations without a special permit" and that throughput capacity in FRPs can be limited because these pipelines "generally have a maximum nominal outer width of 6 inches." 88 *Fed. Reg.* at Hydrogen TSD at 26-27. Permitting challenges aside, it is unclear how this is a reasonable solution given that U.S. transmission pipelines "can range in size from several inches to several feet in diameter,"[156] and "normally [are] between 30 and 36 [inches] in diameter."[157]

The importance of this issue in the United States is evident from the numerous federal efforts currently underway to examine and explore the physical, engineering, and safety issues associated with transporting hydrogen blends in existing natural gas pipelines.[158] For example, in

[155] Wasserstofftransport at 2 (translated using MS Word Translation).
[156] U.S. Dep't of Trans., Fact Sheet: Transmission Pipelines, https://primis.phmsa.dot.gov/comm/FactSheets/FSTransmissionPipelines.htm.

[157] Argonne N'tl Labs., Natural Gas Pipeline Technology Overview (Nov. 2007), https://corridoreis.anl.gov/documents/docs/technical/apt_61034_evs_tm_08_5.pdf.

[158] ClearPath also has noted that "[r]esearch shows small proportions of hydrogen can be directly blended into our existing natural gas network. Blending larger ratios requires more research because natural gas pipelines were not designed with hydrogen in mind." ClearPath, Hydrogen 101, https://clearpath.org/tech-101/hydrogen-101/.

early 2021, DOE launched its HyBlend initiative, which includes over 20 partners and 6 national labs and $15 million in R&D portfolio projects that are anticipated to run from 2021 through 2023.[159] HyBlend "aims to address technical barriers to blending hydrogen in natural gas pipelines. Key aspects of HyBlend include materials compatibility R&D, technoeconomic analysis, and environmental life cycle analysis that will inform the development of publicly accessible tools that characterize the opportunities, costs, and risks of blending."[160] Importantly, DOE also recognizes that blend limits for pipelines can vary greatly depending on the design and condition of current materials, infrastructure equipment, and applications that currently use natural gas.[161]

Furthermore, PHMSA hosted a three-day public meeting November 30 through December 2, 2021, to provide "an opportunity for pipeline stakeholders to discuss research gaps and challenges in pipeline safety and emerging fuels, including hydrogen transportation."[162] The topics for workgroup discussion included hydrogen network components and utilization of inspection tools on hydrogen pipelines, including pipelines carrying hydrogen and natural gas

[159] U.S. Dep't of Energy, HyBlend: Opportunities for Hydrogen Blending in Natural Gas Pipelines, at 1 (June 2021), https://www.energy.gov/sites/default/files/2021-08/hyblend-tech-summary.pdf.

[160] *Id*.

[161] *Id*.

[162] Pipeline Safety: Pipeline Transportation; Hydrogen and Emerging Fuels Research and Development (R&D) Public Meeting and Forum, 86 *Fed. Reg.* 58,389, 58,389 (Oct. 21, 2021).

blends.[163] PHMSA's agenda explains that "[t]o advance the safe transportation of hydrogen gas and/or hydrogen gas blended with natural gas (hydrogen/blends) through the Nation's pipeline network, additional research is necessary."[164] This includes the effects of hydrogen on various pipeline materials[165] "to determine the suitability of the materials for transporting hydrogen and hydrogen/blends in distribution networks," as well as the impacts of hydrogen at varying levels on facilities that are critical to the transmission and distribution network, such as compressor station equipment and meter stations.[166] Discussion during this meeting resulted in the identification of multiple, specific R&D gaps in areas including the integrity of underground hydrogen storage, utilization of inspection tools on hydrogen pipelines, and hydrogen network components.

PHMSA currently is engaged in multiple research projects on point, including projects (1) to identify integrity threats specific to hydrogen transportation by pipeline and potential changes to the America Society of Mechanical Engineers codes;[167] (2) focused on practical methods to

[163] Pipeline and Hazardous Materials Safety Admin., Meetings and Documents, Pipeline Transportation: Hydrogen and Emerging Fuels R&D Public Meeting and Forum, https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=153.
[164] *Id*.

[165] These include polyethylene, polyvinyl chloride, and steel pipes. *Id*.

[166] *Id*.

[167] *See* Pipeline and Hazardous Materials Safety Admin., Review of Integrity Threat Characterization Resulting from Hydrogen Gas Pipeline Service, https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=985.

optimize and repurpose existing pipeline infrastructure to safely transport hydrogen;[168] (3) to advance hydrogen leak detection and quantification technologies compatible with hydrogen blends;[169] (4) focused on the development of compatibility assessment models for existing pipelines for handling hydrogen-containing natural gas;[170] (5) to develop a holistic risk assessment, mitigation measures, and decision support platforms to accelerate the transition towards sustainable, precise, and reliable hydrogen infrastructure;[171] and (6) to determine steel weld qualification and performance for hydrogen pipelines.[172] PHMSA's, other agencies', and industry's work on these issues is a critical precursor to our ability to safely and reliably transport hydrogen in existing U.S. pipelines.

Research and development of advanced sensor equipment capable of accurately detecting hydrogen emissions also are underway. For example, DOE recently issued an $8-11 million labs call that includes a request for "proposals involving lab-developed technologies for development and commercialization of technologies that can quantify leakage of H2 during its production,

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[168] *See* Pipeline and Hazardous Materials Safety Admin., Determining the Required Modifications to Safely Repurpose Existing Pipelines to Transport Pure Hydrogen and Hydrogen-Blends, https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=978.

[169] *See* Pipeline and Hazardous Materials Safety Admin., Advancing Hydrogen Leak Detection and Quantification Technologies Compatible with Hydrogen Blends, https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=979.

[170] *See* Pipeline and Hazardous Materials Safety Admin., Procedures for Retrofitting Indoor Gas Service Regulators, https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=916.

[171] *Id*.

[172] *See* Pipeline and Hazardous Materials Safety Admin., Determining Steel Weld Qualification and Performance for Hydrogen Pipelines, https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=976.

distribution, storage, and use, with detection capabilities in ambient air at the ppm or ppb (more desirable) level."[173] Moreover, while blending can move significant volumes of hydrogen, "separating and purifying the hydrogen from natural gas is difficult."[174]

These challenges present real questions about the timing and scale of a U.S. clean hydrogen economy that EPA must address in its analysis that hydrogen blending is adequately demonstrated. Hydrogen blending will not be achievable throughout the power sector without appropriate and timely scale up of midstream infrastructure. Moreover, in some regions, there may not be pipeline capacity to blend additional hydrogen, or other end users might not be able to utilize hydrogen blends. These issues are significant and unaddressed by EPA and, as a consequence, its proposed adequate demonstration determinations are insufficient.

2. EPA does not adequately analyze critical regulatory issues for interstate pipelines that could impact achievability throughout the industry.

Interstate pipelines provide an economy of scale that can promote efficient and cost-effective transportation, but modifications to our existing interstate pipeline system will be required to accommodate hydrogen. This includes building new and/or modifying existing physical infrastructure, as well as adding and/or updating statutory authority and regulations related to the use of the pipeline capacity. Currently, questions remain as to which federal agency, if any, would have jurisdiction over these areas and what level of authority the relevant agency would

[173] U.S. Dep't of Energy, National Laboratory Call for Proposals: Fossil Energy and Carbon Management Program-Led Topics, DE-LC-000L101 (FY 2023), https://www.energy.gov/fecm/lab-call-technology-commercialization-fund?utm_medium=email&utm_source=govdelivery.
[174] Clean Hydrogen Liftoff Report at 16.

have. Federal legislative efforts to resolve these questions presently are pending.[175] In the absence of federal siting and permitting authority, pipeline project developers must apply to states, which have varying requirements and approval timelines.

Even where federal siting and permitting authority exists for pipelines, as is the case for interstate natural gas pipeline facilities, the various permitting requirements and potential appeals can significantly slow down the process. This is evidenced by several recent interstate pipeline projects, including the Mountain Valley Pipeline project, which submitted its request to commence the FERC pre-filing process in 2014[176] and received FERC authorization in 2017.[177] Over the last six years, the project has faced challenges to several permits required for construction and operation.[178] Recent federal legislation expressly "ratifies and approves" all authorizations required for construction and initial operation of the Mountain Valley Pipeline,[179]

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[175] *See, e.g.,* Building American Energy Security Act of 2023, S.1399, 118th Cong. (2023) (proposing to add hydrogen to the Natural Gas Act).

[176] Pre-Filing Request, Mountain Valley Pipeline, FERC Dkt. No. PF15-3-000 (Oct. 27, 2014) (Accession number 20141027-5136).

[177] *Mountain Valley Pipeline*, 161 FERC ¶ 61,043 (2017).

[178] *See, e.g., Sierra Club v. FERC*, 68 F.4th 630, 636 (D.C. Cir. 2023); *Sierra Club v. W. Virginia Dep't of Env't Prot.*, 64 F.4th 487, 496 (4th Cir. 2023); *Sierra Club v. State Water Control Bd.*, 64 F.4th 187, 191 (4th Cir. 2023); *Sierra Club v. FERC*, 38 F.4th 220, 226 (D.C. Cir. 2022); *Appalachian Voices v. United States Dep't of Interior*, 25 F.4th 259, 265 (4th Cir. 2022); *Wild Virginia v. United States Forest Serv.*, 24 F.4th 915, 920 (4th Cir. 2022); *Mountain Valley Pipeline, LLC v. N.C. Dep't of Env't Quality*, 990 F.3d 818, 823 (4th Cir. 2021); *Sierra Club v. United States Army Corps of Eng'rs*, 981 F.3d 251, 260 (4th Cir. 2020); *Appalachian Voices v. FERC*, 2019 WL 847199, at *1 (D.C. Cir. Feb. 19, 2019); *Sierra Club v. United States Army Corps of Eng'rs*, 909 F.3d 635, 639-643 (4th Cir. 2018); *Sierra Club, Inc. v. U.S. Forest Serv.*, 897 F.3d 582 (4th Cir. 2018).

[179] Fiscal Responsibility Act of 2023, Pub. L. No. 118-5, § 324, 137 Stat. 10, 47-48 (2023).

yet the project still faces hurdles to completing construction. More specifically, in response to requests from petitioners in three pending cases, the U.S. Court of Appeals for the Fourth Circuit issued stays on July 10 and 11, 2023,[180] halting construction. Mountain Valley Pipeline filed an emergency application with the U.S. Supreme Court on July 14, 2023, seeking relief from the Fourth Circuit's decision.[181] In an unsigned order on July 27, 2023, the Supreme Court granted Mountain Valley's request to vacate the Fourth Circuit's stays, but did not grant the pipeline's request to dismiss the underlying actions entirely. Despite EPA's efforts to project future pipeline construction, it is impossible to predict how quickly pipelines will be permitted and built.[182] As a result, EPA's assertions are speculative.

As noted, midstream transportation will be necessary for hydrogen projects that cannot accommodate onsite production, either because they lack the necessary resources or because they have insufficient space.[183] For interstate pipelines, hydrogen likely will be transported in a blend

[180] Order, *The Wilderness Society v. U.S. Forest Service*, No. 23-1592 (4th Cir. July 10, 2023); Order, *The Wilderness Society v. U.S. Forest Service*, No. 23-1594 (4th Cir. July 10, 2023); and Order, *Appalachian Voices v. United States Department of the Interior*, No. 23-1384 (4th Cir. July 11, 2023).

[181] Emergency Application to Chief Justice John G. Roberts, Jr. to Vacate the Stays of Agency Authorizations Pending Adjudication of the Petitions for Review, *Mountain Valley Pipeline, LLC v. Wilderness Soc'y, et al.*, Nos. 23-1592, 23-1594, & 23-1384 (4th Cir. June 2, 2023).

[182] Beyond permitting issues, pipeline projects also can face weather-related construction challenges. Mountain Valley Pipeline notes in its petition before the U.S. Supreme Court that, as of July 14, 2023, it "has only approximately three months to complete the Pipeline before winter weather sets in and precludes significant construction tasks until the spring of 2024." *Id.* at 7.

[183] For example, one EEI member has calculated that it would require 7.5 square miles to accommodate the solar array necessary to reach a 30 percent blend at one facility site (Facility 1) and we need double that amount of land for the array necessary to reach this blend level at a second facility site (Facility 2). To reach a 96 percent blend, the member has calculated that it would need approximately 52.4 square miles for the necessary solar array for Facility 1 and

with natural gas, as well as by itself in dedicated pipelines. It is possible that there will be attempts to regulate these methods of transportation under different statutory/regulatory frameworks. In fact, this may currently be the case as the FERC—at least under its immediately prior chairman—expressed confidence in FERC's authority to regulate pipelines carrying a hydrogen and natural gas blend under the NGA;[184] and, the Surface Transportation Board (STB) previously has exercised economic (rate-related) jurisdiction over dedicated interstate hydrogen pipelines, albeit more in a passive manner in order to resolve a dispute raised by a formal complaint. While this provides an idea of what regulation of interstate transportation of hydrogen by pipeline could look like, neither agency has explicitly confirmed its jurisdiction and some level of congressional action likely would be required to vest authority with either agency.[185]

Importantly, these two regulatory regimes provide the agencies with very different levels of authority. FERC has certificate authority over interstate natural gas pipelines[186] and serves as the lead National Environmental Policy Act agency for new and expansion pipeline development. In recent years, the FERC process has been lengthy, and potential changes to the scope of FERC's

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double that for Facility 2. These significant land requirements make it infeasible to co-locate low-GHG hydrogen production with use at Facilities 1 and 2.

[184] In response to questions from Senator Heinrich, then FERC Chairman Glick indicated that "the Commission has authority under the Natural Gas Act over hydrogen blending with natural gas on interstate pipelines" and that "[t]he Commission would maintain its jurisdiction over an interstate natural gas pipeline if that pipeline were to blend some amount of hydrogen into the gas stream." Letter from Richard Glick, FERC Chairman to Sen. Martin Heinrich, FERC Accession No. 20211027-4000, at 2 (Oct. 26, 2021).

[185] *See, e.g.,* Building American Energy Security Act of 2023, S.1399, 118th Cong. (2023) (proposing to add hydrogen to the NGA).

[186] 15 U.S.C. § 717f.

approach toward pipeline certification and review of greenhouse gas emissions in the environmental review for pipeline projects are pending, which could add complexity to the process.[187] However, rather than apply to each state, interstate natural gas pipeline developers only have to obtain a certificate of public convenience and necessity (CPCN) from FERC. FERC also provides certificate holders with federal eminent domain authority[188] and preempts state and local regulations that "interfere" with FERC's certificate authority.[189]

By contrast, STB's jurisdiction does not include federal siting authority or provide federal eminent domain authority. Instead, pipelines regulated by STB must obtain a CPCN from each of the states that they enter. The requirements for obtaining a CPCN vary by state. Additionally, each state has the ability to impact the overall pipeline process and each state's authorization is susceptible to separate challenge in court.

[187] In early 2022, FERC issued a Draft Updated Pipeline Certificate Policy Statement modifying its 1999 policy statement on the certification of new interstate natural gas facilities under Section 7(c) of the NGA to provide a more comprehensive analytical framework. *Consideration of New Interstate Natural Gas Facilities*, 178 FERC ¶ 61,107 (2022). The Commission also issued a Draft Interim GHG Policy Statement seeking to explain how the Commission will assess the impacts of natural gas infrastructure projects on climate change in its reviews under NEPA and Sections 3 and 7 of the NGA. *Consideration of Greenhouse Gas Emissions in Natural Gas Infrastructure Project Reviews*, 178 FERC ¶ 61,108 (2022). Final versions of these policy statements remain pending.

[188] 15 U.S.C. § 717f.

[189] *See, e.g., Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293, 310 (1988) (state regulation that interferes with FERC's regulatory authority over the transportation of natural gas is preempted); and *Dominion Transmission, Inc. v. Summers*, 723 F.3d 238, 245 (D.C. Cir. 2013) (noting that state and local regulation is preempted by the NGA to the extent it conflicts with federal regulation, or would delay the construction and operation of facilities approved by the Commission).

These significant process differences can yield different timelines for permitting, siting, and constructing new pipelines. The duration of the permitting and construction process is expected to impact development of midstream infrastructure. DOE explains that "[n]ew, dedicated hydrogen pipelines will take time to break ground, in part due to the nascency of the hydrogen economy combined with long construction and permitting timelines."[190] It further explains that "[t]hrough 2030, new hydrogen pipeline use will likely remain limited, as . . . pipeline permitting and construction is a multi-year process; new pipelines are unlikely to be operational until *at least* the late 2020s."[191]

Additional regulatory questions also remain regarding the economic regulation of interstate hydrogen transportation by pipeline. For blended pipelines, these questions include the quantities of hydrogen that could be transported on existing pipelines and allocation of the costs of upgrades that may be needed to allow hydrogen to be carried in existing pipelines.[192] For both blended and dedicated hydrogen pipelines, there are also open questions around the extent to which transportation rates will be regulated and how pipeline capacity will be structured.

[190] Clean Hydrogen Liftoff Report at 50.

[191] *Id*. at n.124 (emphasis added).

[192] As former FERC Chairman Glick explained in a 2021 letter to U.S. Senator Heinrich, for interstate natural as pipelines, this would require that a "pipeline follow the Commission's Policy Statement on Gas Quality and Interchangeability," which includes stakeholder participation and coordination between and among shippers and the pipeline. Letter from FERC Responding to Sen. Heinrich, Oct. 26, 2021 (FERC accession number 20211027-4000) (citing *Policy Statement on Provisions Governing Natural Gas Quality and Interchangeability in Interstate Natural Gas Pipeline Company Tariffs,* 115 FERC ¶ 61,325 (2006)).

Resolving these regulatory issues will take time and the uncertainty that they create could delay investment in this sector. EPA does not discuss or appear to have considered these issues in reaching its proposed adequate demonstration determinations. Adequate access to midstream infrastructure is critical to scaling the U.S. clean hydrogen economy and to the power sector's ability to deploy hydrogen blending. EPA's failure to analyze these regulatory gaps and their impact is a significant flaw in its record and undermines its proposed adequate demonstration determination.

3. EPA does not adequately analyze the investment gap for new infrastructure, which could impact achievability throughout the industry.

In addition to the open regulatory questions noted above, new pipeline construction is capital intensive. EPA recognizes this challenge in the Hydrogen TSD, noting that "[t]he capital costs of new pipeline construction constitute a barrier to expanding hydrogen pipeline delivery infrastructure." 88 *Fed. Reg.* at Hydrogen TSD at 26. However, the Agency does not include significant discussion of this challenge or appear to have taken it into consideration in its proposed determinations.

While there has been investment in hydrogen production, driven by the hydrogen PTC, "[m]idstream and end-use infrastructure investments face a more acute financing gap."[193] More specifically, DOE explains as much as half of the "$85-215B of cumulative investment [that] is required to scale the domestic hydrogen economy through 2030" will be for midstream and end-use infrastructure.[194] At present, while almost all of the investment requirements for 2030

[193] Clean Hydrogen Liftoff Report at 42.

[194] *Id*.

production would be covered if production projects secure financing, "project announcements only cover . . . ~5% of distribution and storage infrastructure needs."[195]

EPA notes that the funding that H2Hubs will provide for infrastructure. While the H2Hubs are anticipated to help support infrastructure development, infrastructure that is part of these projects may not be in full operation until the early- to mid-2030s despite the best efforts of both DOE and industry at getting the hubs operational.[196] In addition, the H2Hubs are intended to be regionally focused at first and eventually to provide connective tissue to support a national clean hydrogen economy. As a result, it is unclear whether the H2Hubs will provide sufficient midstream infrastructure to support clean hydrogen deployment at scale early in their operation and EPA's reliance on this program alone is insufficient evidence to support its proposed adequate demonstration determinations.

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[195] *Id*. at 43.

[196] H2Hub awards are anticipated in Fall 2023. DOE plans to execute H2Hubs funding over four phases that could range from 8-12 years. Under DOE's plan, the construction is not anticipated to begin for three to five years after the award and could take an additional two to four years to complete, with ramp-up to full operation occurring over the subsequent two to four years. U.S. Dep't of Energy, *Funding Opportunity Announcement: Regional Clean Hydrogen Hubs*, at 19-22 (Jan. 26, 2023), https://oced-exchange.energy.gov/. Assuming awards are made on the anticipated timeline, H2Hub project construction would begin in late 2026 on the early end and late 2028 on the later end. For projects that begin construction in late 2026, construction could be complete between late 2028 and late 2030 and operations would ramp up between 2030 and 2034. For projects that begin construction in late 2028, it could be complete between late 2030 and late 2032 with operations ramping up between 2032 and 2036. These timelines are based on DOE's projections for the H2Hubs and could be elongated by factors including permitting delays, supply chain challenges, and workforce shortages.

iii. EPA does not adequately analyze storage-related challenges that could impact achievability throughout the industry.

As noted above, EPA explains that it "believes hydrogen distribution and storage infrastructure will not present a barrier to access for" combustion turbines opting for low-GHG hydrogen blending under the Proposed 111 Rules. *See, e.g.,* 88 *Fed. Reg.* at 33,309. However, EPA does not discuss several technical challenges associated with hydrogen storage and bases its conclusions on H2Hubs funding, which, as discussed above, may not be in full operation until the early- to mid- 2030s.

Hydrogen can be stored in above ground or underground facilities and can be stored as a pressurized gas or as a cryogenic liquid. DOE explains "[h]ydrogen storage is a key enabling technology for the advancement of hydrogen and fuel cell technologies in applications including stationary power," but given hydrogen's properties, "[it] require[es] the development of advanced storage methods that have potential for higher energy density."[197] This is particularly the case for underground storage, which is anticipated to be critical for scaling up hydrogen deployment beyond the current levels. As discussed below, underground hydrogen storage presently faces several challenges and technical barriers.

From a safety perspective, in addition to the pipeline-related topics noted above, PHMSA explored several topics related to hydrogen storage during its three-day meeting. This included "expand[ing] its research portfolio in the safe underground storage of hydrogen gas and/or

[197] U.S. Dep't of Energy, Hydrogen Storage, https://www.energy.gov/eere/fuelcells/hydrogen-storage.

hydrogen blended with natural gas."[198] With respect to integrity of underground storage systems, PHMSA plans to explore a "wide array of topics" including reducing leaks from underground storage facilities and new technologies to mitigate leaks, the degree and consequences of mixing hydrogen with cushion gas, and the compatibility of hydrogen with underground storage environments.[199] Utilization of geologic storage also would be limited by geography. Furthermore, the International Energy Agency recently explained that "[w]hile there is no practical experience in repurposing methane caverns for hydrogen service, it is estimated that such an approach would require about the same amount of time as developing a new salt cavern."[200]

It has also been noted that while underground storage would be useful for storing the large quantities of hydrogen required for applications like power generation, it presents a number of challenges. These include: "1) assessment of the risks of corrosion of storage vessels and development of mitigation strategies, 2) determination of the effects of soil pressure on the tank, [and] 3) assessment of the effects of tank leakage on the surroundings."[201] Where hydrogen is stored in a liquid (cryogenic state), ground freezing is a potential challenge and the potential for

[198] Pipeline and Hazardous Materials Safety Admin., Meetings and Documents, Pipeline Transportation: Hydrogen and Emerging Fuels R&D Public Meeting and Forum, https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=153.
[199] *Id*.

[200] Int'l Energy Agency, Global Hydrogen Review 2021, p 151 (Oct. 2021) https://www.iea.org/reports/global-hydrogen-review-2021.

[201] U.S. DRIVE Partnership, Hydrogen Delivery Technical Team Roadmap, at 20 (July 2017), https://www.energy.gov/sites/prod/files/2017/08/f36/hdtt_roadmap_July2017.pdf.

seismic activity and resulting effects on storage need to be determined.[202] In addition, advances in materials, including those for aboveground storage, may be needed. For example, materials to store hydrogen must be resistant to embrittlement and fatigue and be capable of maintaining structural integrity at cryogenic temperatures.[203] This may require the use of novel construction materials.[204]

As noted, EPA points to the H2Hubs to support its conclusion that storage infrastructure will not present a barrier to reliable and affordable low-GHG hydrogen blending in compliance with the Proposed 111 Rules. However, EPA proposes that combustion turbines blend 30 percent low-GHG hydrogen by 2032. As discussed in the preceding section, DOE's plan for the H2Hubs includes four phases and the project funding is expected to span 8-12 years. With award announcements anticipated in Fall 2023, the H2Hubs projects may not be operational until the early- to mid-2030s, potentially after 2032 even despite the best efforts of DOE and industry to make the hubs a reality. As such, the H2Hubs may not be ready in time to provide the support that EPA assumes and EPA's reliance on this program alone is insufficient to support its proposed adequate demonstration determinations.

e. EPA's proposed conclusions are based on an insufficient record as the Agency fails to consider factors that could impact low-GHG hydrogen's cost-effectiveness and achievability throughout the industry.

EPA states that low-GHG hydrogen, as proposed, will be cost-effective, *see, e.g.,* 88 *Fed. Reg.* at 33,242-43, and proposes to conclude that "the increase in operating costs from a BSER based on

[202] *Id*.
[203] *Id*.
[204] *Id*.

low-GHG hydrogen is reasonable." *Id.* at 33,314. However, as the starting point for its cost analysis, EPA relies on DOE's Hydrogen Earthshot, which aims to reduce electrolytic hydrogen production costs to $1/kg by 2030. Critically, this represents an 80 percent reduction in the cost of clean hydrogen[205] and DOE itself explains that the Hydrogen Earthshot "sets an ambitious . . . target based on stretch R&D goals"[206] and that it "create[es] bold, ambitious goals to galvanize domestic and global industry."[207] While industry and government will continue to aim to meet this target, it is not a reasonable basis for EPA's cost analysis, particularly for a technology that faces the multiple hurdles set forth in these comments, which EPA also fails to analyze. As discussed below, EPA does not take into account a number of factors that could impact costs, including electrolyzer availability, clean electricity costs, transportation costs, water cost and availability, and the contours of the pending hydrogen PTC guidance that will inform entities' ability to use the credit. This failure is a significant flaw in the record and undermines EPA's proposed adequate demonstration determinations.

i. EPA does not adequately analyze electrolyzer availability and clean electricity costs that could impact low-GHG hydrogen's cost-effectiveness achievability throughout the industry.

Two significant components of the cost of low-GHG hydrogen are electrolyzer availability and clean electricity costs. Current areas of development and related challenges that government and industry are working to overcome for each are discussed above. Importantly, the timing and

[205] *See* U.S. Dep't of Energy, Hydrogen Shot, https://www.energy.gov/eere/fuelcells/hydrogen-shot.

[206] Clean Hydrogen Liftoff Report at 2.

[207] U.S. Dep't of Energy, U.S. Clean Hydrogen Strategy and Roadmap, at 39 (June 2023), https://www.hydrogen.energy.gov/clean-hydrogen-strategy-roadmap.html.

scope of scale up for these two components, which currently are unknown, could impact the cost of low-GHG hydrogen.

For example, DOE explains in the Clean Hydrogen Liftoff Report that reducing the capex for electrolyzer manufacturing "will be the largest driver of near-term electrolysis cost reductions (through 2030)."[208] The scale of cost reductions needed is not insignificant—"[e]lectrolyzers need to see 50–80% cost declines by 2030 to follow the growth pathway detailed in [the Clean Hydrogen Liftoff] report. While standardization, design to value and manufacturing scale-up will represent a significant portion of the cost-down, technological innovation is also needed."[209] DOE also notes that industry forecasts for electrolyzer capex cost-downs "do not yet reach the Hydrogen Fuel Cell Technology Office (HFTO) targets of ~$100 - $250/kW (late 2020s to early 2030s) motivating the need for additional R&D funding to bridge the gap."[210]

The cost of clean electricity is similarly a significant factor in the overall cost of low-GHG hydrogen production. For example, DOE explains that "a 15% increase in electricity costs can reduce returns 3-5%. Constrained clean power build out can also limit the deployment of electrolyzers."[211] As discussed above, competition for clean electricity is anticipated to be significant, particularly as multiple sectors simultaneously seek to use increasing quantities of clean electricity and as challenges to its scale up remain.

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[208] *Id*. at 13.

[209] *Id*. at 66.

[210] *Id*. at 13.

[211] *Id*. at 35.

Moreover, the levelized capex costs for electrolyzers are inversely proportional to their utilization (capacity factor). As a result, "[r]enewable capacity factors will impact hydrogen production costs."[212] While energy storage can improve the capacity factors associated with wind and solar, energy storage technologies are experiencing their own scale up and related challenges.[213] DOE also notes that "using hydro and nuclear power can run at high-capacity factors (>90%) allowing for lower levelized capex costs."[214] However, as noted above, it is unclear whether and to what extent existing energy resources, such as hydropower and nuclear, will qualify under the hydrogen PTC. Similarly, while power purchase agreements can be used to contract for non-dedicated clean electricity, "[a]dditional regulatory clarity for producers seeking to capture the PTC would help accelerate further private upstream investment."[215] Moreover, while using electricity from the grid enhances electrolyzer utilization, it also is unclear whether and to what extent this pathway could take advantage of the hydrogen PTC.

As noted, EPA does not discuss these factors or take them into account in its analysis. Not doing so is a significant gap in EPA's record and undermines EPA's proposed adequate demonstration determinations.

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[212] *Id*. at 12.

[213] *See* U.S. Dep't of Energy, Pathways to Commercial Liftoff: Long Duration Energy Storage (Mar 2023), https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-LDES-vPUB.pdf.

[214] Clean Hydrogen Liftoff Report at 12.

[215] *Id*. at 12.

ii. EPA does not adequately analyze midstream costs that could impact low-GHG hydrogen's cost-effectiveness and achievability throughout the industry.

The delivered cost of low-GHG hydrogen also will depend significantly on the cost of transportation and storage. As DOE explains, "[d]istribution and storage can more than double the delivered cost of hydrogen. Near-term use cases where hydrogen supply and demand are not co-located will be significantly affected by the high cost of hydrogen distribution, with the exception of regions with existing, scaled hydrogen pipeline networks."[216] These costs will vary, but some stakeholders have reported current distribution and storage costs of up to $10/kg, depending on the storage and transportation methods used.[217]

EPA also cites DOE's estimate that, with a potential electrolytic production cost of $0.40/kg by 2030 (inclusive of the hydrogen PTC), the delivered cost of hydrogen could be approximately $0.70/kg to $1.15/kg. 88 *Fed. Reg.* at 33,309. Critically, DOE notes that these estimates "assume[ ] lowest-cost clean hydrogen production in 2030 as well as a range of distribution / storage options (compression to pipeline, pipeline, and storage fee associated with pipeline storage)."[218] As discussed above, the extent of development of pipelines capable of carrying hydrogen remains unclear and government and industry are working to overcome the hurdles necessary to support a U.S. clean hydrogen market at scale.

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[216] *Id*. at 57.

[217] *Id*. at n.133.

[218] *Id*. at n.65.

Where pipelines are not available, hydrogen trucking is anticipated to be the main mode of transportation. However, the costs alone for delivering hydrogen by truck could exceed EPA's anticipated delivered cost of hydrogen noted above. More specifically, DOE estimates that in 2030,[219] midstream transportation costs could be $0.2-0.4/kg for compression for trucking plus $0.7-1.5/kg for gas phase trucking service, for a total of $0.9-1.9/kg for compressed hydrogen by truck—for liquid hydrogen delivery by truck, which EPA notes will be required for longer distances, 88 *Fed. Reg.* at Hydrogen TSD at 29, DOE estimates $2.7/kg for liquefaction and $0.2-0.3/kg for liquid hydrogen trucking service, for a total delivered transportation cost of $2.9-3.0/kg. By comparison, DOE's estimated 2030 costs for pipeline delivery are $0.1/kg for compression and $0.1/kg for pipeline transportation, for a total delivered cost of $0.2/kg.

The Proposed 111 Rules do not analyze these potential costs and their impact on EPA's proposed determination beyond mentioning that gas phase and liquid trucking are distribution options, 88 *Fed. Reg.* at 33,309; *see also id.* at Hydrogen TSD at 25 and 28, and a cursory mention of related costs. *Id.* at Hydrogen TSD at 29. This failure is a significant gap in EPA's rulemaking record and undermines EPA's proposed adequate demonstration determinations.

iii. EPA does not adequately analyze how the potential contours of the IRA hydrogen PTC could impact low-GHG hydrogen's cost-effectiveness and achievability throughout the industry.

As discussed above, Treasury guidance on the hydrogen PTC remains outstanding and has the potential to help or hinder low-GHG hydrogen costs and, in turn, demand. For example, as discussed above, it is anticipated that Treasury may include additionality requirements in its guidance. Depending on the terms of these requirements, hydrogen producers seeking to use

[219] *Id*. at 4.

electricity from existing hydropower and nuclear facilities may not qualify for the full hydrogen PTC.

Treasury also is considering the timeframe over which the lifecycle greenhouse gas emissions for hydrogen production must be measured and discussion has centered around either annual matching or hourly matching. As EEI explained in its comments to Treasury,[220] hourly matching is estimated to increase the cost of green hydrogen production by 70-170 percent[221] versus annual matching, eliminating the ability of the PTC to make low-GHG hydrogen cost competitive with other forms of hydrogen. This is because hourly matching would require a low-GHG hydrogen project to buy time-correlated renewables during periods of under-generation, which corresponds to higher market price periods, increasing the overall cost of green hydrogen. If time-correlated renewables are not available, the low-GHG hydrogen project may curtail its electrolyzer, leading to long idle times. Hydrogen production equipment remains expensive and requires high utilization to make hydrogen production facilities economic. If a low-GHG hydrogen production facility can only produce during hours when wind and solar are available, the low utilization rate will dramatically increase the price of the hydrogen produced. Furthermore, applications requiring an uninterrupted flow of hydrogen represent substantially all existing hydrogen uses, and thus, requiring hourly matching would severely limit the adoption of low-GHG hydrogen.

[220] Comments of the Edison Electric Institute, U.S. Dep't of Treasury Request for Comments on Credits for Clean Hydrogen and Clean Fuel Production (Notice 2022-58), (Dec. 6, 2022), https://www.regulations.gov/comment/IRS-2022-0029-0072.

[221] Assumes 95 percent electrolyzer capacity for annual matching and 70 percent, 60 percent, and 50 percent capacity for hourly matching at high, mid, and low renewable resource, respectively.

As with the factors discussed above, EPA does not discuss these issues or appear to take them into account in its analysis. This failure is a gap in the rulemaking record and undermines EPA's proposed adequate demonstration determinations.

f. EPA's proposed conclusions are based on an insufficient record as the Agency fails to consider several other issues that could impact achievability throughout the industry.

In addition to those noted above, there are several other areas of developmental need that must be met to ensure development of the U.S. clean hydrogen market that will be necessary to support reliable and affordable low-GHG hydrogen blending in the power sector. These include the need to scale up and train the workforce that will underpin this hydrogen market and the need to resolve accounting-related questions.

i. EPA fails to adequately analyze workforce challenges that could impact achievability throughout the industry.

Although well-recognized, EPA does not mention workforce-related challenges. In the Clean Hydrogen Liftoff Report, DOE explains that expansion of a skilled workforce will be critical to near-term expansion.[222] For example, DOE notes that "[e]lectrolysis will be challenged by supply-chain constraints in both raw materials and equipment manufacturing capacity during a critical scale-up period through 2025 in addition to challenges with renewables build-out and *sourcing a domestic workforce*."[223] In terms of scope, in 2030, DOE estimates that

[222] *See, e.g.,* Clean Hydrogen Liftoff Report at 3.

[223] *Id*. at 45 (emphasis added).

approximately 200,000 workers across direct and indirect jobs would be needed to support the deployment of clean hydrogen at scale.[224] In addition,

> [Engineering procurement, and construction (EPC)] providers will need specialized experience, sufficient workforce, and established contract structures for hydrogen production and refueling projects. The U.S. does not currently have a sufficient, appropriately skilled workforce to manufacture, construct, or operate the volume of hydrogen infrastructure required to meet projected demand, so scaling this workforce presents both a challenge and an opportunity.[225]

New skills that would be required include "electrolyzer and electrolyzer component manufacturing, fuel cell expertise, and electrolysis facility engineering, procurement, and construction (EPC) expertise."[226] Moreover, "accelerated clean energy deployment is likely to further constrain EPC capacity."[227]

As noted, EPA does not discuss these issues or appear to have taken them into consideration in its proposed determinations. This failure is a significant flaw in the record and undermines EPA's proposed adequate demonstration determinations.

ii. EPA fails adequately analyze the impact of other sectors' use of hydrogen on achievability of low-GHG blending throughout the power sector.

Building the U.S. clean hydrogen market will require a thoughtful approach that recognizes that scale up in certain sectors, like the power sector, will rely heavily on other sectors' clean hydrogen deployment. DOE's H2Hubs program is a good example of such an approach. As

[224] *Id*. at 58.
[225] *Id*. at 48.

[226] *Id*. at 58.

[227] *Id*. at 58.

explained above, DOE intends to engage in a four-phased process with awardees and to initially focus on regional and local market development. The ultimate hope is to connect the H2Hubs to form a nationwide clean hydrogen market economy. While such a market would support achievability of hydrogen blending throughout the power sector, we must first build up local and regional markets. These markets will be critical to enabling development of the economies of scale necessary to reduce cost and increase both supply and demand and will form the necessary foundation for the deployment of clean hydrogen at scale.

Moreover, as DOE explains based on its analysis of the various current barriers facing hydrogen liftoff, "[b]y 2030, most demand for low carbon hydrogen is likely to be as a drop-in replacement for carbon-intensive hydrogen currently used in ammonia and oil refining. Sectors where hydrogen is not an incumbent technology, such as other industrial sectors (steel, chemicals), transportation, heat, *and power, will take more time to uptake clean hydrogen*."[228] Furthermore, "[i]nitial deployments using clean hydrogen are expected to leverage regional energy resources and target industries that currently rely on conventional natural gas to hydrogen technologies (without CCS)."[229] This expectation is logical as these sectors already have the infrastructure in place to support clean hydrogen use. These sectors will be key to scaling up clean hydrogen production, reducing cost, and, critically, supporting the buildout of the midstream infrastructure,[230] all of which will be needed to support achievability of hydrogen blending

[228] *Id*. at 9 (emphasis added).

[229] U.S. Dep't of Energy, U.S. Clean Hydrogen Strategy and Roadmap, at 12 (June 2023), https://www.hydrogen.energy.gov/clean-hydrogen-strategy-roadmap.html.

[230] *See, e.g.,* Clean Hydrogen Liftoff Report at 16 ("Pipelines also require a stable, credit-worthy offtakers who will demand significant volumes of hydrogen sufficient to justify dedicated infrastructure build-out."). *See also id.* at 57 ("Near-term use cases where hydrogen supply and

throughout the power sector.

Whether and to what extent these sectors will adopt clean hydrogen remains to be seen, particularly given the challenges noted above. EPA does not analyze how other sectors' adoption of clean hydrogen will impact access to low-GHG hydrogen and, ultimately, achievability of hydrogen blending throughout the power sector.

iii. EPA fails to adequately analyze accounting-related gaps and their impact on achievability throughout the industry.

Given that hydrogen is a fungible molecule once produced, any emissions requirements for hydrogen production will require standardized accounting and traceability. EPA recognizes this fact and seeks comment on "what forms of acceptable mechanisms and documentary evidence should be required for EGUs to demonstrate compliance with the obligation to blend low-GHG hydrogen, including proof of production pathway, overall emissions calculations or modeling results and input, purchasing agreements, contracts, and energy attribute certificates." 88 *Fed. Reg.* 33,240, at 33,328. Efforts are underway to establish these mechanisms, but they are nascent at present. The absence of these mechanisms further demonstrates the current early stage of development of a clean hydrogen market, the important open questions that entities are working to resolve, and the premature nature of EPA's proposal. Furthermore, how these questions are resolved could impact development of the U.S. clean hydrogen market—if cumbersome accounting regimes emerge, they could have a chilling effect on market growth.

3. EPA's proposal to define low-GHG hydrogen in the Proposed 111 Rules is arbitrary and EPA should instead propose separate rules for hydrogen producers.

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demand are not co-located will be significantly affected by the high cost of hydrogen distribution, with the exception of regions with existing, scaled hydrogen pipeline networks.").

There are several issues that stem from EPA's proposal to mandate the use of "low-GHG" hydrogen for units that opt for the blending pathway and to include emissions reductions requirements for hydrogen production as part of that mandate. As a preliminary matter, the regulation of hydrogen production is beyond the scope of proposed rule; if EPA seeks to regulate emissions from hydrogen production, it must do so through a process that satisfies the section 111 requirements for that separate source category and does not impede development of this nascent, but important resource.

a. EPA's "low-GHG" hydrogen requirement is beyond its authority and the Agency should utilize a separate 111 process to set any production standard.

EPA's proposal to define "low-GHG" hydrogen effectively seeks to establish an emissions limitation for hydrogen production. Setting novel, upstream requirements for hydrogen as part of this CAA section 111 proposal is beyond the appropriate scope of the proposed rule.

EPA has set upstream emissions limitations for other fuels used in EGUs—namely, natural gas. Notably, EPA's emissions limitations for natural gas production have been set through rulemakings regulating natural gas production, transportation, and storage, not the power sector as one of the consumers of natural gas.[231] Such an approach tailors EPA's regulations to the sector and facilities that own and operate the affected facilities. EPA's regulation of source categories under section 111 should be focused on the facilities with emissions. For the power sector, those source categories, therefore, appropriately focus on the emissions stack. Fuel production, like natural gas and hydrogen, occurs outside of the stack—in some instances,

[231] *See, e.g., Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, 87 *Fed. Reg.* 74,702 (Dec. 6, 2022).

hundreds or even thousands of miles away. Accordingly, it is not part of the relevant source categories and should not be included in a rule that addresses power sector stack emissions.

If EPA wishes to regulate emissions associated with hydrogen production industry, it should do so in a separate section 111 process focused on the hydrogen industry. To do otherwise would be arbitrary as it would treat differently the two fuels that would be used in EGUs—hydrogen and natural gas—without viable rationale for doing so. Further, as EPA notes, hydrogen combustion in EGUs has no carbon emissions. This is the case regardless of how the hydrogen is produced because, once produced, hydrogen molecules effectively are fungible. As a result, emissions at an EGU, which are the focus of the proposed rule, are not impacted by the hydrogen production pathway.

Moreover, while some electric companies may produce hydrogen, electric companies are not the only entities who will produce hydrogen for use in EGUs or otherwise. Given its focus on the power sector, the attempt to regulate hydrogen producers through the proposed rule is inappropriate.

Additionally, given that hydrogen is a fungible molecule once produced, any emissions requirements for hydrogen production will require standardized accounting and traceability. As noted *supra*, EPA recognizes this fact and seeks comment on "what forms of acceptable mechanisms and documentary evidence should be required for EGUs to demonstrate compliance with the obligation to co-fire low-GHG hydrogen, including proof of production pathway, overall emissions calculations or modeling results and input, purchasing agreements, contracts,

and energy attribute certificates." 88 *Fed. Reg.* 33,240, at 33,328. Efforts are underway to establish these mechanisms, but they are nascent at present.

The challenges with accounting and traceability run counter to EPA's traditional methods of compliance for the power sector. The power sector complies at the stack—not at the input of fuel. This fact is further reason why EPA should issue a separate standard for hydrogen production emissions and why it is inappropriate to include production emissions reductions requirements in the proposed rule.

Consequently, regulation of hydrogen production is outside of the scope of EPA's authority to regulate at the unit and therefore beyond the scope of the proposed rule. EPA should propose any such standards in a separate rulemaking.

b. EPA should address hydrogen production challenges in a separate rulemaking.

In seeking to set hydrogen production requirements, EPA notably eschews setting a separate standard for hydrogen production, although it notes it has the authority to set hydrogen production standards. Indeed, as noted, EPA has set section 111 standards for natural gas production and it could, and should, do so for hydrogen production as well, particularly if it seeks to use "Low-GHG" hydrogen as part of the BSER for EGUs. However, there are several important factors that any hydrogen production standard must take into account, including that EPA must adhere to the section 111 process in setting a hydrogen production emissions standard. In addition, EPA must also consider that setting a hydrogen production standard for the power sector will have *de facto* impacts on development of the hydrogen economy more broadly, which

is critical to hydrogen's ability to overcome the challenges that will be necessary to enable its use in EGUs. This includes:

- *Achievability Challenges EPA Needs to Address:* For "low-GHG" hydrogen production, the elements of the system include renewable electricity, water, and electrolyzers—and, as discussed above, each faces challenges. Taken together, these demonstrate that EPA's assumptions that there will be sufficient "low-GHG" hydrogen to support "achievability throughout the industry" is simply unsubstantiated and is not addressed by EPA in attempting to set an upstream hydrogen production standard in the proposal.[232]
- *Cost Barriers*: As discussed above, it is well-recognized that there currently are cost barriers to electrolytic hydrogen production. For example, DOE is highly focused on reducing the cost of hydrogen to assist in providing a foundation for development of hydrogen at scale. As noted in 2021, DOE launched the Hydrogen Earthshot, aimed at reducing the cost of electrolytic hydrogen from $5/kg to $1/kg by 2030.[233] In addition, the IIJA includes a $1 billion investment in Clean Hydrogen Electrolysis Program.[234] The purpose of this program is to establish a research, development, demonstration, commercialization, and deployment program for purposes of commercialization to

[232] DOE also notes several other challenges to development of a hydrogen economy at scale, including the absence of standard contract structures, which are delaying project financing; hesitancy to commit to long-term, scaled offtake for several potential reasons, including limited price discovery or price certainty, unavailability and reliability of supply, near-term policy implementation uncertainty, and long-term political uncertainty; limited cost-effective midstream infrastructure, which negatively impacts market development beyond production centers; limited availability of specialized hydrogen workforce; credit risk that is constraining widespread debt-financing; scale-up challenges for specific end-uses; and various challenges impacting long-term growth. Clean Hydrogen Liftoff Report at 56-62.

[233] U.S. Dep't of Energy, Hydrogen Shot, https://www.energy.gov/eere/fuelcells/hydrogen-shot.

[234] IIJA at § 816(b).

improve the efficiency, increase the durability, and reduce the cost of producing clean hydrogen using electrolyzers.[235]

- *Non-Air Quality Health and Environmental Impacts*: In addition, producing electrolytic hydrogen using renewable energy may implicate non-air quality health and environmental impacts. For example, it is anticipated that hydrogen may drive significant demand for new renewable energy projects—particularly if Treasury's 45V guidance includes hourly matching and additionality requirements, as discussed further below. The International Renewable Energy Agency has projected that renewable electricity demand for hydrogen will range from 30-120 exajoules by 2050.[236] In addition, the Hydrogen Council has noted that "gigawatt-scale projects can be a significant local water consumer. In regions prone to water supply stress, sea water desalination is required."[237]

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[235] *See* U.S. Dep't of Energy, Clean Hydrogen Electrolysis Program, https://www.energy.gov/bil/clean-hydrogen-electrolysis-program.

[236] Int'l Renewable Energy Agency, *Hydrogen: A Renewable Energy Perspective,* p 22 (Sept. 2019), https://www.irena.org/publications/2019/Sep/Hydrogen-A-renewable-energy-perspective. Columbia University SIPA's Center on Global Energy Policy recently noted that "[g]rowing demand of green hydrogen will require enormous investment and construction of electricity transmission, distribution and storage networks, and much larger volumes of zero-carbon power generation, as well as electrolyzer production systems, some hydrogen pipelines, and hydrogen fueling systems. An 88 million tons per annum (Mtpa) green hydrogen production by 2030, corresponding to the Stated Policies Scenario from the International Energy Agency (IEA) for that year, could cost $2.4 trillion and require 1,238 gigawatts (GW) of additional zero-carbon power generation capacity." Columbia Univ. SIPA: Ctr. on Global Energy Policy, *Green Hydrogen in a Circular Carbon Economy: Opportunities and Limits*, pp 8-9 (Aug. 2021), https://www.energypolicy.columbia.edu/research/report/green-hydrogen-circular-carbon-economy-opportunities-and-limits.

[237] Hydrogen Council, *Hydrogen Decarbonization Pathways: A Lifecycle Assessment*, p 8 (Jan. 2021), https://hydrogencouncil.com/wp-content/uploads/2021/01/Hydrogen-Council-Report_Decarbonization-Pathways_Part-1-Lifecycle-Assessment.pdf.

- *Reliance on Tax Credits*: As discussed above, electrolytic hydrogen production faces several cost barriers at present. Treasury is in the process of developing guidance for implementation of these tax credits. This guidance will dictate entities' ability to utilize the credit and, in turn, whether the tax credit actually enables "low-GHG" hydrogen to overcome its current cost barriers. Without the Treasury guidance and market reaction, it is unclear whether the 45V tax credits will be successful. The potential for either outcome increases the uncertainty around whether and how successful the 45V tax credits will be in enabling "low-GHG" hydrogen to overcome current cost barriers. Moreover, even if the IRA tax credits remain in place and are funded, they are set to expire December 31, 2032. Development of the hydrogen economy is anticipated to take place over several decades and it is unclear how expiration of the 45V tax credits in the early stages of hydrogen deployment will impact future development. It is possible, given the various other challenges to be overcome, that "low-GHG" hydrogen will not be cost-effective relative to other energy resources by December 31, 2032.[238]
- *Requiring "Low-GHG" Hydrogen for the power sector will have impacts on other sectors*: In setting a requirement that the power sector only utilize "Low-GHG" hydrogen, EPA should bear in mind that its standard will have impacts on the development of the hydrogen economy more broadly. The power sector is one of many sectors exploring the potential to use hydrogen as a tool to continue to reduce emissions and meet climate goals. Any production standard that EPA sets for the power sector will

[238] Clean Hydrogen Liftoff Report at 3 ("If electrolysis projects fail to scale during the IRA credit period, electrolysis may not achieve the necessary learning curves to remain competitive in the absence of tax credits.").

flow through to commercial agreements and has the potential to influence how other sectors define "low-GHG" hydrogen in their operations, which should be done in a separate rulemaking for addressing emissions from hydrogen production.

While it is anticipated that these issues will be surmounted in the near term, at present these issues have yet to be overcome and create challenges for "low-GHG" hydrogen production.

c. EPA should take the lead in setting a hydrogen production emissions standard.

EPA defers significantly to Treasury in the proposed rule in setting the emissions requirements for hydrogen production—both in defining "low-GHG" hydrogen to align with the most stringent emissions level for the hydrogen production tax credit under the IRA and in proposing to adopt Treasury's ultimate guidance on point, including potentially adopting temporal matching, geographic limitation, and additionality requirements. However, authority to regulate air emissions under the CAA rests with EPA, not with Treasury. Moreover, as noted above, EPA is bound by CAA section 111 when it sets emissions limitations. While it may defer to other agencies as appropriate, it cannot use such deference to avoid satisfaction of these process requirements. As part of that rulemaking process, EPA should fulsomely consider the impact of hydrogen production and focus on emissions standards that can be achieved across the spectrum while taking into account the statutory factors described above. To that end, EPA should consider allowing a wider array of hydrogen production sources to qualify as "low-GHG" hydrogen than is contemplated under the current definition, including hydrogen produced using CCS and other sources beyond renewable energy. As noted, availability of resources to produce hydrogen varies across the United States and the infrastructure required to cost-effectively transport hydrogen, faces several challenges to development. These factors weigh strongly in favor of a more inclusive standard to promote development of the U.S. clean hydrogen economy

at scale and to enable availability of hydrogen blending throughout the power sector. EPA should also consider whether it has the ability to require these resources to be additional, as well, given the structure and set up of CAA section 111's regulation of both new and existing sources.

Moreover, as discussed *supra*, some of the principles Treasury is considering as part of its 45V guidance would hinder the near-term hydrogen development that will be critical to ensuring a robust hydrogen economy that ultimately could support the use of hydrogen in EGUs. These principles include Treasury's consideration of an hourly matching requirement.

Hydrogen production equipment remains expensive and requires high utilization to make hydrogen production facilities economic. If a green hydrogen production facility can only produce during hours when wind and solar are available, the low utilization rate will dramatically increase the price of the hydrogen produced. Furthermore, applications requiring an uninterrupted flow of hydrogen represent substantially all existing hydrogen uses, and thus, requiring hourly matching would severely limit the adoption of green hydrogen. Such limitation ultimately would undermine the ability to meet EPA's proposed standards for EGUs.

4. Conclusion.

EPA states that it is "confident that these proposed NSPS and emission guidelines – with the extensive lead time and compliance flexibilities they provide – can be successfully implemented in a manner that preservers the ability of power companies and grid operators to maintain the reliability of the nation's electric power system." 88 *Fed. Reg.* at 33,246. However, as set forth above, EPA does not analyze or appear to take into account the various, significant, interrelated areas of development and scale ups that must occur to achieve the hydrogen economy that will

be needed to support its Proposed 111 Rules, the infrastructure necessary to deliver the low-GHG hydrogen to EGUs across the industry, or the market necessary to support low-GHG hydrogen cost effectiveness. While efforts across government and industry are underway to overcome these well-recognized challenges, they create uncertainties about how and when the U.S. clean hydrogen economy that will be needed to support reliable and affordable hydrogen blending in the power sector will emerge.

IV. EPA's Proposed Phase One Standards for New Natural-Gas Based Units Are Appropriate But Several Key Technical Changes Are Required To Ensure These Standards Are Achievable.

For new units, the CAA requires that EPA make a BSER determination for the source category and then define the resulting emissions limitations that will be applicable to all units in that source category. *See* 42 U.S.C. § 7411(b). EPA proposes three subcategories for new natural gas turbines regulated under 40 C.F.R. part TTTT, which includes both NGCCs and CTs, each with its own proposed BSER and resulting emissions limits: a low load, intermediate load, and base load units. *See* 88 *Fed. Reg.* at 33,277.[239] The phase one requirements for each subcategory are detailed below:

- **Low load units:** For units with capacity factors less than 20 percent, the proposed BSER is the use of lower emitting fuel. EPA proposes that the use of natural gas, Nos. 1 and 2 fuel oils, and low-GHG hydrogen qualify as lower emitting fuels. EPA is proposing an emission standard of between 120 and 160 lb CO_2/MMBtu.

- **Intermediate load units:** A new combustion turbine NGCC qualifies as an intermediate unit if it has a capacity factor less than 45-55 percent; a new CT qualifies if it has a capacity factor less than 33-40 percent. For these units, EPA proposes efficient operations as the phase one BSER, with an emissions limit of 1,150 lb CO_2/MWh.

[239] EPA proposes these revised standards in light of the Agency's decision to revisit these existing standards for subpart TTTT units as part of the statutorily required eight-year review. *See* 88 *Fed. Reg*. at 33,277; *see also id*. at 33,279.

- **Base load units:** An combustion turbine with a capacity factor greater than 45-55 percent qualifies as a baseload unit. EPA is proposing efficient operations as the phase one BSER, with an emissions limitation of 770 lb CO_2/MWh for units with nameplate heat inputs greater than 2,000 MMBtu/hr; for smaller units, the proposed emissions limitation is between 770 and 900 lb CO_2/MWh depending on the specific base load rating of the combustion.[240]

Id.[241] EPA also proposes phase two standards for base load and intermediate load units and—for base load hydrogen units—phase three standards. *See id*. Legal and technical issues raised by EPA's proposed phase two and three standards are discussed *supra*.

EPA is correct that the BSER for the proposed phase one standards for new baseload and intermediate natural gas units is the most efficient generation. Because these phase one standards are applicable upon proposal, *see* 42 U.S.C. § 7411(a)(2)(defining a new source as one that commences construction or modification after the publication of proposed regulations), efficient generation is the only adequately demonstrated technology that could serve as BSER for immediately applicable standards. EPA acknowledges this indirectly by proposing a phased

[240] Actual capacity factor and utilization data that determine membership in a particular subcategory will be a unit-specific inquiry that also considers a unit's design efficiency. Confusingly, EPA proposes that units undertake this analysis annually, meaning that units could move between subcategories every year, often due to factors outside of their control (e.g., system needs). *See* proposed 40 C.F.R. § 60.5580a. This poses significant challenges for compliance planning, as discussed herein.

[241] The phase one standards also require that affected units be operated and maintained efficiently. *See* 88 *Fed. Reg*. at 33,283; *see als*o proposed 40 C.F.R. § 60.5525a(b). Efficient—or as the proposed regulatory text states—operations and maintenance (O&M) consistent with safety and good air pollution control and using "consistent operations and maintenance procedures" is an appropriate requirement. EPA states that good practices include but are not limited to minimizing energy losses uses insulation and blowdown heat recovery. *See* 88 *Fed. Reg*. at 33,287. In any final rule, EPA should provide more details about what else the Agency considers good O&M practices and how the Agency will evaluate compliance with such requirements. EPA also clearly should state that the Agency will not second guess operations, particularly those that are in response to grid emergencies.

approach to BSER, implicitly recognizing that the control technologies that it asserts are BSER for later phases have not been adequately demonstrated at this time. *See* 88 *Fed. Reg*. at 33,283. Further, as EPA notes, efficient generation quantifies as BSER because it also can be implemented at reasonable cost and does not have adverse environmental or energy impacts. *See id*. at 33,288. For similar reasons, EPA is correct that clean fuels are BSER for low load units.

EPA should, however, make several key technical changes to the proposed standards that result from these BSER determinations. EPA must show that these standards are achievable, as required by CAA section 111(a). See 42 U.S.C. § 7411(a)(1). In order for the standards to be achievable, EPA must account for the future operations of these units in an evolving and cleaner grid that is actively integrating increasing amounts of more intermittent, renewable resources. EPA also must demonstrate that the proposed emission rate limit is achievable over a 12-month rolling average period, which is how affected units are required to demonstrate compliance.

EPA should set achievable, efficiency-based standards for new natural gas-based units, consistent with EEI's February 2023 recommendation to the Agency that these units be "capable" of future retrofit to install CCS or blend hydrogen when those technologies are demonstrated and available at costs that are affordable for customers. Further, EPA should adopt a modified approach to intermediate load units to account for the differences between combined cycle units and CTs and should increase the capacity factor limitation for low load units to allow these units to play the reliability critical role for which they usually are deployed. Finally, EPA should make clear that new units are able to take a mass-based approach to compliance, which will offer necessary and significant operational flexibility.

A. EPA Must Adjust the Phase One Standards for Base Load Units to Account for Unit Operations and Consistent With EPA's Own Compliance Demonstration Requirements.

EPA is correct that the phase 1 BSER for new "base load" natural gas NGCC units is the most efficient generation. *See* 88 *Fed. Reg*. at 33,277. Using this BSER, EPA proposes to establish an emissions rate standard of 770 lb CO_2/MWh for NGCCs with nameplate heat inputs greater than 2,000 MMBtu/hr. *See id*. at 33,322. However, EPA has not demonstrated that this proposed emissions rate is achievable across the industry and across a full range of likely operating conditions. Principally, EPA does not take into consideration how these units actually operate to support variable renewable resources, nor does it consider how emissions performance degrades over time. EPA should increase the emissions rate to account for these realities and finalize an emissions rate that is more supported by recently permitted new units than EPA's proposed standard.[242] EPA also should provide for mass-based compliance options with the phase 1 standards. EPA also should provide full weight to the comments of turbine manufacturers and EEI's member companies that are working to build and deploy these NGCC units, since the potential for cycling and the ability of these manufacturers to guarantee the phase one performance limits is essential for ensuring that EPA's initial, efficiency-based approaches are done appropriately and supported by the record and are technically achievable.

1. The phase one standards for new base load NGCCs does not take into consideration expected unit operations that will result in higher emissions rates.

[242] EPA is seeking comment on a range of potential standards, from 730 to 800 lb CO_2/MWh. *See* 88 *Fed. Reg*. at 33,332. EPA should not lower the standard. The reasons cited in these comments for increasing the standard also militate that the standard not be lowered further than the proposed 770 lb CO_2/MWh level.

EPA's proposed phase 1 standard does not appropriately consider the variability in the operating modes of new "base load" NGCCs. Even those units that operate at higher relative capacity factors, when measured on an annual basis, are unlikely to maintain high capacity factors at all times. EPA, without discussion, assumes that all units that operate at higher annual capacity factors are serving as "base load" generation at all times and that intermediate load units are load following and provide dispatchable backup power to support variable renewable generating sources. *See id*. at 33,278. But this is overly simplistic and ignores the changes in the generating fleet that EPA acknowledges elsewhere in the Proposed 111 Rules. Because of the increase in generation from variable renewable energy resources—which are dispatched first when available—even higher capacity NGCC units will have to adjust their generation to meet generation needs on an hourly or daily basis. EPA provides no data to support this assumption that units operate in only one way—at high capacity factors—at all times. While this convention (higher capacity factors are baseload units and lower capacity factors are load following units) might be useful for subcategorizing units for the purposes of standards development, it can bear little relationship to actual unit operations, which presents compliance and operational challenges. EPA is obligated to ensure achievability of these standards, which means that the Agency must account for these operational realities when setting NSPS.

The generation profile of the industry is changing dramatically, including greater deployment of renewable generation, and this trend will continue.[243] As a result, the manner in which baseload NGCCs will operate in the future will result in the frequent cycling of these units—and, indeed,

[243] *See, e.g*., AEO 2023, Release Presentation at 11-14 (Mar. 16, 2023), https://www.eia.gov/outlooks/aeo/pdf/AEO2023_Release_Presentation.pdf.

higher levels of cycling (resulting in lower capacity factors) already are required of many currently operating newer NGCCs in areas with significant renewable deployments.[244] Renewable energy sources provide variable generation by their nature; combined cycle, simple cycle and quick start natural gas-fired units are essential elements to integrating this variable generation and are increasingly being called upon to ramp up and down in response to these often quick and unpredictable changes.[245] As EEI noted in its 2014 and 2018 comments, combined cycle and combustion turbines play an essential role in continuing the clean energy transition by providing 24/7 and quick start power, which allows for increased renewable integration and reliable power at affordable rates for customers.

The practical effect of this is that new natural gas-based units will likely cycle more often in future years, and thus not operate at steady state operations for extended periods of time, which will have an impact on the unit's ability to meet the proposed standard of 770 lb CO_2/MWh. More frequent starts and stops means that a unit is operating in periods with reduced efficiency and a higher emission rate. This increased cycling puts the achievability of EPA's proposed 770 lb CO_2/MWh in question for even the most advanced turbines.

[244] *See, e.g.*, EIA, *Natural Gas Combined-Cycle Plant Use Varies by Region and Age* (May 20, 2021)(, https://www.eia.gov/todayinenergy/detail.php?id=48036.

[245] EPA acknowledges this in a roundabout way in the *Efficient Generation: Combustion Turbine Electric Generation Units Technical Support Document*, Docket ID No. EPA-HQ-OAR-2023-0072 (May 2023), which states that "combined cycle EGUs [are] a more dependable power source for load-following supply."

Second, as a unit cycles more frequently, the degradation in performance of that unit happens more rapidly.[246] In proposing the current standard of 770 lb CO_2/MWh, EPA asserts that the proposed rate fully accounts for degradation of the unit, *see* 88 *Fed. Reg.* at 33,323, but as discussed in more detail below, EPA does not provide any data to support this claim. As proposed, the current emission rate does not provide sufficient flexibility to account for any increases in degradation that will result from the more frequent cycling, i.e., starting and stopping of a unit, and provides no support for the assertion that the proposed emissions rate fully accounts for degradation in light of how units are anticipated to operate.

Examining the most recently issued permits issued for NGCC units is instructive. While EPA does cite a number of units operating at an annual basis at or below 770 lb CO_2/MWh, there are several caveats EPA does not address. First, these units are all very recently constructed, and are operating before significant degradation and/or wear and tear have impacted unit performance. And, as new units, these facilities are operating at higher capacity factors because they are the most efficient units available for dispatch, meaning that they are dispatched first.[247] However, these units are not *permitted* at the rates EPA asserts they are performing at on an annual basis, with many permitted near or above 800 lb CO_2/MWh. Take, for example, the Orange County Advanced Power Station (OCAPS) in Texas, which commenced construction this spring and is

[246] *See, e.g.,* Intertek, *Update of Reliability and Cost Impacts of Flexible Generation on Fossil-Fueled Generators for Western Electricity Coordinating Council*, Report No. AIM 191210726-2-1 (May 20, 2020), https://www.wecc.org/Reliability/1r10726%20WECC%20Update%20of%20Reliability%20and%20Cost%20Impacts%20of%20Flexible%20Generation%20on%20Fossil.pdf.

[247] When all units are similarly highly efficient, they all would not be able to run at the highest possible capacity factors, rendering reliance on these units even less apt.

being built by EEI member Entergy.[248] OCAPS is a 1,215 MW facility utilizing two Mitsubishi M501JAC enhanced air-cooled gas turbines in a 2x1 configuration with a heat recovery steam generator (HRSG) and advanced control system. OCAPS is also a hydrogen-capable facility, that will be initially capable of 30 percent hydrogen blending by volume and is poised to blend hydrogen in future years when it is available, with some retrofits.[249] Critically, OCAPS' Prevention of Significant Deterioration (PSD) permit requires that OCAPS meet a limit of 814.7 lb CO_2/MWh gross on a 12-month rolling average basis. *See* Texas Council on Environmental Quality PSD Permit, Special Condition 30.

OCAPS represents a very advanced combined cycle facility that includes a HRSG, which EPA deems essential to achieving high levels of efficiency, and the permitted level is notably above EPA's proposed emissions standard of 770 lb CO_2/MWh. This is practical and logical: the permitted level for new facilities—facilities that will operate for decades in the future and must be in compliance with their permitted rate at all times—must take into account long term unit operations, degradation, and other relevant factors that can impact unit performance, providing for flexibility and operational head room across a range of potential to probable operating conditions.

Also instructive is EPA's own admission that "nearly half of recently constructed combined cycle EGUs have maintained an emissions rate of 800 lb CO_2/MWh." 88 *Fed. Reg*. at 33,324. In light

[248] *See* Entergy, About the Project, https://www.entergy.com/entergypowerstexas/project/.

[249] this represents the capability of the turbine and not necessarily an expectation that sufficient hydrogen supplies (much less low-GHG hydrogen supplies) will exist to enable this level of co-firing to be sustained.

of this, EPA seeks comment on whether the Agency should instead adopt this higher emissions rate on the grounds that it "would increase flexibility and reduce costs to the regulated community by allowing more available designs to operate as base load combustion turbines." *Id*. The answer to the Agency's question is yes, EPA should consider setting a higher emissions standard than proposed since such an approach would be in line with the approach that EPA took in the final rule setting standards that are applicable to new NGCCs built after January 8, 2014. In that rulemaking, EPA selected 1,000 lb CO_2/MWh as the achievable emissions rate derived from the same BSER[250]—efficient generation—because it provided for operational flexibility, considered actual operating parameters and potential future degradation, as well as unit-specific design. *See Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Final Rule*, 80 *Fed Reg.* 64,510, 64,620 (2015 NSPS).[251] EPA should continue to adopt this approach in any final NSPS for base load NGCCs, since considering a range of factors when determining whether an emissions rate is achievable is both defensible and reasonable.

However, EPA has deviated from the approach it took in the Agency's 2015. More importantly, EPA is conflating its obligation to determine the BSER with its statutory obligation to ensure that the emissions limits based on BSER that are applied to new units are achievable. "Best" is a modifier for "system of emission reduction" in CAA section 111(a)(1); it is not a term used to

[250] EPA selected 1000 lb CO_2/MWh as the achievable emissions rate despite the fact that the "lowest emitters in the CAMD database" at that time had emissions rates of closer to 800 lb CO_2/MWh. *See* 80 *Fed. Reg*. at 64,618. EPA selected this emissions rate despite the fact that it anticipated that most new units likely would have better performance.

[251] It should be noted that whether the standard for new base load NGCCs is 770 lb CO_2/MWh or 800 lb CO_2/MWh, this would represent a significant emissions performance over the current standard.

describe the resulting emissions standard. EPA is not required by the CAA section 111(a)(1) to select the lowest or from among the lowest emissions rates that could be produced by the application of BSER, but instead is required to establish a standard that is achievable. *See* 42 U.S.C. § 7411(a)(1). While an achievable emissions standard is not required to be meetable by every single unit, as per the relevant case law, EPA has an obligation to demonstrate achievability "under the most adverse conditions that might be expected to occur" and which cannot be taken into account via an assessment of costs. *See Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 433, n.46 (D.C. Cir. 1980).[252]

Here, EPA is not being asked to take into consideration the most adverse conditions, but merely the most likely conditions, as it did in 2015, which include increased cycling and the resulting degradation. Therefore, given the increased cycling and the attendant degradation as these units continue to adapt to changing grid conditions that EPA has not addressed and EPA's own observations about the achievability of a higher emissions standard, EPA should take these obvious likely conditions into account and select a higher standard that would provide more operational flexibility and compliance margin to account for these reasonably anticipated unit impacts. A higher standard is more appropriate, as it would account for the manner in which baseload units will be operating in the future to account for a great increase in intermittent generation resources and the increase in cycling of units.

[252] *See also Sierra Club v. Costle*, 657 F.2d 298, 377 (D.C. Cir. 1981)(To show that a standard is achievable, the EPA must ''(1) identify variable conditions that might contribute to the amount of expected emissions, and (2) establish that the test data relied on by the agency are representative of potential industrywide performance, given the range of variables that affect the achievability of the standard.'').

2. EPA has not demonstrated that new NGCC units can achieve the proposed emissions rate using the required compliance demonstration metrics.

EPA asserts that the proposed 770 lb CO_2/MWh emissions rate for new base load NGCCs has been demonstrated, but EPA has not provided underlying data that is supportive of this assertion. Further, EPA appears to be using a different metric for its demonstration that this rate is achievable than the one that EPA would require units to use when proving compliance. Accordingly, this provides a separate basis for determining that EPA has not shown that that the proposed rate is achievable, contrary to the requirements of the CAA, and therefore cannot be finalized.

In the proposed Section 111 Rules, EPA states that "[a]n emissions rates of 770 lb CO_2/Mwh-gross has been demonstrated by 14 percent of the recently constructed combined cycle EGUs." 88 *Fed. Reg*. at 33,323. However, while EPA provides a chart that summarizes what EPA refers to as "the maximum 12-operating month base load emissions rate" for the "best performing" combustion turbines in an appendix to the *Technical Support Document (TSD) Efficient Generation: Combustion Turbine Electric Generating Units* that was included in this docket, *see id*. at 33,324, EPA provides insufficient information in the TSD about how the "12-operating month" rates were calculated, including information about the number of startups and shutdowns, capacity factors, total MWh generated, or other details that would help stakeholders, including the owners and operators of potential new affected NGCCs units, understand how EPA arrived at this conclusion and how the units compare to their own recently constructed NGCCs.

At minimum, EPA should provide such data and more information about how it calculated these "maximum 12-operating month rates." In addition, EPA asserts that these units cited as the best performers "have long-term emissions data that fully account for potential degradation in efficiency." *Id*. at 33,323. However, EPA does not provide that data in either this proposal or the docket to support this claim or to allow comments opportunity to review it. As noted, this approach is markedly different from the significant and detailed analysis of achievability, including degradation and other factors, undertaken by the Agency in establishing an achievable emissions limit for new NGCCs in the 2015 NSPS. EPA should provide this additional data or reconsider its approach.

EPA also appears to be using a different metric for computing the "12-operating month baseload emissions rate" than the metric that unit owners and operators would be required to use to demonstrate compliance, which can be problematic. EPA does not define what it means by a 12-operating month emissions rate, although it appears to be an annual average emissions rate. It is not clear how EPA's assertion that this rate demonstrates that the proposed emissions limit of 770 lb CO_2/MWh can be achieved when the proposed subpart TTTTa would require compliance be demonstrated using a 12-operating month rolling average. *See* proposed 40 C.F.R. at 60.5525a(a)(1).[253] EPA is correct that annual averages could provide operational flexibility, but this could be eroded if the averaging period is rolling or if EPA intends that 12-operating month rolling average is similar to a 12-month rolling average, which is the way that compliance is

[253] Assuming that the mandate "You must be in compliance with the emission standards in this subpart that apply to your affected EGU at all times" does not override any effort to provide compliance flexibility via longer averaging periods than are provided under subpart TTTT normally. *See* proposed 40 C.F.R. § 60.5525a(A).

currently demonstrated under subpart TTTT. Given this mismatch, EPA has not shown that the standard it has selected can be achieved using the appropriate compliance metric it requires. At minimum, EPA must make such a showing before asserting that a standard is achievable.

3. EPA can help units achieve compliance with the proposed emissions rate standards by authorizing mass-based compliance.

EPA also should affirmatively allow for mass-based compliance options for new units. While NSPS are traditionally set on an efficiency rate basis, allowing companies to translate the rate-based standard into a mass-based tonnage limitation would provide significant operational flexibility for units that cycle frequently—e.g., that ramp "up and down," operate at various loads, or have frequent startups and shutdowns to meet grid demands, as discussed here. Instead of having units meet a continuously applicable rate, which limits their ability to integrate newer and cleaner resources, allowing companies to translate the BSER rate into a mass-based tonnage limit would provide for environmental integrity, offer more straightforward compliance options, allow for more efficient operations, and support utility planning based on known unit constraints via tonnage limits. While such approaches could provide "less" environmental protection in the context of traditional air pollutants, these potential impacts are actively managed by state permitting agencies through the PSD permitting process, and such concerns are not relevant for GHGs, which are well mixed in the atmosphere once emitted, minimizing localized pollution concerns. EPA should affirmatively provide a mass-based compliance option for new units. Providing this flexibility does not ameliorate EPA's failure to demonstrate that the proposed emissions limit for new base load NGCC units is achievable, but, when coupled with an increase in the standard, would address many of the concerns regarding compliance raises in these comments.

B. EPA Should Clarify Requirements for Intermediate-Load Units.

The proposed intermediate subcategory applies to NGCCs that have a capacity factor less than approximately 45-55 percent and CTs that have a capacity factor less than approximately 33-40 percent. *See* 88 *Fed. Reg.* at 33,277. EPA proposed as its phase 1 emission limit for these units a rate of 1,150 lb CO_2/MWh. *See id.* at 33,319. Units that would be classified as intermediate-load units serve a key role in the ongoing transition of the electric sector by assisting with renewables integration and providing essential reliability services at smaller sizes and lower capacity factors than base load units. However, the application of a capacity factor restriction to these units, in addition to an emission rate limitation, unnecessarily constrain the ability of these units to operate in a way that supports both the transition of the sector to carbon free resources, but also grid reliability.

EEI raised similar concerns in the past about capacity factors limiting the use of efficient turbines —units opted to curtail operations rather than be subject to more stringent standards—resulting in less efficient and more carbon intensive units be called upon to support grid reliability. These same concerns are valid here with respect to the intermediate subcategory being subject to both a capacity factor and emission rate limitations. In effect, having both a rate limitation *and* a capacity factor limitation that limits the efficient operations of those units at load—despite the potential utilization of multi-year averaging—constrains the ability of units to operate and be in compliance by having both restrictions fundamentally work against one another.

To encourage the construction and use of these efficient units, EPA should remove the capacity factor limitation and only restrict units to an emission limit to ensure that the most efficient units,

and correspondingly, the most environmentally protective units are operating. By providing both a capacity factor limitation and an emissions performance standard, EPA will unnecessarily limit operations while simultaneously attempting to drive for the more efficient operations, despite the fact that those efficiencies tend to only occur at higher capacity factors. If EPA nonetheless believes that lower emissions rates and limited operations can be simultaneously achieved, EPA must provide significantly more analysis showing that units that operate under a 50 percent capacity factor can also achieve the phase one standards EPA proposes—for both combined cycle turbines and CTs.

In the alternative, EPA should also consider setting a separate, capacity factor or emissions rate limit that would apply only to new CT units. This would allow EPA to have a base load and intermediate-load category approach for NGCC units, while also working to set up a parallel structure for CTs that could allow for greater flexibility for units that can help with renewables integration. Ultimately, EPA should choose between approaches—a capacity factor restriction, or an emissions rate limitation, and not both at once.

C. In defining Low-Utilization Units, EPA Should Finalize a Higher Capacity Factor to Account for Reliability Considerations.

EPA also proposes a low-load subcategory for units that operate at capacity factors less than 20 percent but is soliciting feedback on a range between 15-25 percent. *See* 88 *Fed Reg*. at 33,321. EPA acknowledges that these low load units provide critical services in support of grid reliability, including ramping capabilities during periods of peak electric demand. *See id.* at 33,320. EPA reaches this conclusion on the basis that one-third of recently constructed units operate under this capacity factor, while 80 percent of recently constructed units have operated at a capacity factor of 25 or less. *See id*.

Grid reliability is and will continue to be a top priority for EEI's member companies. With an increase in extreme weather events, including high heat events, extreme winter storms, wildfires, hurricanes, and other threats to the electric grid, in addition efforts to electrify many segments, including the transportation and industrial sectors, of the economy, the industry will require to use of all available resources at times of peak demand, which will likely become even more frequent.

As a result, many of the units that would be classified as low load units will be called upon to support grid reliability with more frequency in the future but would be unable to meet more stringent emission limitations of the intermediate subcategory because of the manner in which they are called upon to operate. This could result units operating until they reach their 20 percent capacity factor, and then shutting down to not be subject to stricter limits, resulting in a gap in generation or the generation being supplied by less efficient and more carbon intensive units such as diesel reciprocating internal combustion engine units.

EPA should therefore increase the capacity factor limitation for low load units to at least 25 percent. This will allow these low load units to operate to support grid reliability in an environmentally protective manner compared to alternatives. EEI's member companies view these low-load turbines as essential to preserving system reliability while integrating ever higher penetration of renewable resources onto the grid. Finalizing a higher capacity factor will allow for members to build fewer of these units while also allowing them to be available when needed for grid reliability situations. EEI's member companies are filing individual comments in support

of EPA finalizing this higher threshold for the low-load category; EPA should full take those comments and concerns into account and finalize the 25 percent capacity factor limitation as a result.

V. Compliance Flexibilities Are Essential To A Workable Final Rule; EPA Should Both Finalize And Expand Proposed Flexibilities And Provide Additional Options To States And Units.

EPA has the ability to provide a range of flexibilities, both in the standard setting process and in defining compliance options. This is grounded in the text of CAA section 111 and, broadly, in EPA's decades-long implementation of the CAA. In general, regulatory—e.g., standard setting—and compliance flexibilities are a practical and longstanding method of helping affected sources comply with environmental regulations in efficient, cost-effective, and commonsense ways. The electric sector has long experience implementing emissions trading regimes, averaging provisions, and permit-specific terms in ways that achieve cost effective and efficient compliance. These flexibilities have contributed to the broad and continued success of the CAA in reducing pollution and promoting public health and are common features of environmental statutes: EPA generally is authorized to set standards and then provided compliance pathways that enhance the options available to industry and states—instead of limiting the methods and manners that sources can use to meet those same standards.

A recent EPA report acknowledges this important feature of environmental regulation: Since the 1990 CAA amendments, the many flexible compliance regimes promulgated by the Agency have resulted in significant emissions reductions and a marked reduction in unhealthy air quality days,

all at lower than predicted costs to industry and customers.[254] Many of the regulatory programs enacted by EPA to attain and maintain the NAAQS in the past three decades have contained significant regulatory flexibilities—from market-based trading,[255] to wide ranging averaging provisions,[256] to creative permit terms,[257] to innovative methods of estimating reductions from new industry activities.[258] In summary, EPA has set standards and targets, and American industries have worked to engineer the least cost and most effective way to meet these via supportive and flexible regulatory frameworks from their states and EPA.

In this rulemaking, EPA has the opportunity and authority under CAA section 111 to incorporate compliance flexibilities and mechanisms to help EGUs reduce GHG emissions. EPA has included several important and well-founded compliance flexibilities in the Proposed Section 111 Rules. In any final rule, EPA should both retain and expand the proposed compliance flexibilities and explicitly authorize mass-based approaches to demonstrating compliance, encourage state-

[254] EPA, Our Nation's Air, https://gispub.epa.gov/air/trendsreport/2019/#naaqs.

[255] *See, e.g.,* Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone, 63 *Fed. Reg.* 57356 (Oct. 27, 1998); the Clean Air Interstate Rule, 70 *Fed. Reg.* 25,161 (May 12, 2005); the Cross-State Air Pollution Rule (CSAPR), 76 *Fed. Reg.* 48,208 (Aug. 8, 2011); the CSAPR Update Rule, 81 *Fed. Reg.* 74,504 (Oct. 26, 2016); and the Revised CSAPR Update Rule, 86 *Fed. Reg.* 23,054 (Apr. 30, 2021).

[256] *See* Florida State Implementation Plan Approval for Hillsborough County, 82 *Fed. Reg.* 30,749 (July 3, 2017).

[257] *See* Prevention of Significant Deterioration/Title V Greenhouse Gas Tailoring Rule, 75 *Fed. Reg.* 31,513 (June 3, 2010).

[258] *See* EPA, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans (July 2012), https://www.epa.gov/sites/production/files/2016-05/documents/eeremanual_0.pdf.

driven trading programs, allow units to use averaging to demonstrate compliance, and allow for these flexibilities to apply to both existing coal- and natural gas-based units. These flexibilities will be essential for compliance, particularly if EPA chooses to finalize emissions standards for new and existing sources similar to those proposed.

A. Mass-Based Approaches Should be Explicitly Authorized in the Final Guidelines and in the Final Rule for New Sources.

EPA proposes that units would demonstrate compliance with the presumptive rate-based standards annually based on the lb CO_2/MWh emission rate derived by dividing the total reported CO_2 mass emissions by the total reported electric generation for an affected EGU during the compliance year, which is consistent with the expression of the degree of emission limitation proposed for each subcategory. *See* 88 *Fed. Reg.* 33,375. EPA also separately takes comment on, and notes that states could implement, mass-based emissions approaches, including mass-based trading. *Id*. at 33,393.

1. EPA should explicitly authorize mass-based approaches for existing sources to allow for straightforward compliance.

Given that EPA references the D.C. Circuit's decision in *American Lung Association* finding that states and units are not required to implement EPA's proposed BSER in order to comply with CAA section 111 standards, and that a mass-based input is required for compliance with a rate-based approach, states seemingly could choose to propose mass-based compliance approaches for existing units. *American Lung Association*, 985 F.3d 914, 957. EPA should be explicit in any final rule that it will approve mass-based compliance demonstrations included in state plans. This would enable straightforward compliance with an annual emissions tonnage limit instead of the annual emissions rate and provide a more direct route to implementing any trading program. As discussed in detail in a whitepaper that EEI filed in the non-regulatory docket that preceded this

proposal, mass-based compliance also provides significant operational flexibility.[259] This allows units to operate within a mass-based limitation and ensure availability to cycle, incorporate variable resources, and respond to grid conditions without having the limitations regarding rate-based approaches that struggle to account for startup and shutdown emissions and conditions.

Mass-based approaches will help states utilize other flexibility tools, like averaging, trading, and using lower-GHG fuels in a more straightforward and least-cost way. This will allow for numerous other flexibilities to be utilized as well, including the ability to link existing state-based programs, as discussed *infra* in these comments, as well as straightforward incorporation of mass-based limitations into unit-specific permits. Mass-based approaches will allow consistency and seamless integration with existing state programs that measure compliance based on mass emissions, while still achieving the program goals of net reductions in greenhouse gas emissions. EPA should explicitly authorize mass-based approaches to accommodate these additional flexibilities.

2. EPA should explicitly authorize states to use mass-based compliance for new sources.

EPA also should affirmatively allow for mass-based compliance options for new units. NSPS are traditionally set on an efficiency rate basis; for EGU GHG standards, these are expressed in pounds of CO_2 per hour. Allowing companies to translate the rate-based standard into a mass-based tonnage limitation would provide significant operational flexibility for units that cycle frequently—e.g., that ramp "up and down," operate at various loads, or have frequent startups and shutdowns to meet grid demands—which are becoming more essential and more common as

[259] *See* EEI Whitepaper, attached as Appendix B.

greater amounts of variable renewable resources interconnect to the grid. Further, cycling degrades individual unit efficiency since units operate more efficiently at higher load profiles when compared to continued cycling. Instead of requiring units to meet a continuously applicable rate, which limits their ability to integrate newer and cleaner resources, allowing companies to translate the BSER rate into a mass-based tonnage limit would provide for environmental integrity, offer more straightforward compliance options, and support utility planning based on known unit constraints via carbon dioxide tonnage limits. While such approaches would provide less environmental protection in the context of traditional air pollutants, such concerns are not relevant for GHGs, which are well-mixed in the atmosphere once emitted.[260]

EPA should also consider that operating efficiency is also correlated to a combined cycle CTs ambient conditions. Highly efficient operations are not available under all ambient conditions and vary based on the location of a CT. EPA should also consider degradation of efficiency over time. An additional benefit would be ease of incorporating these units into state-based trading schemes, as discussed *supra*, to the extent states would like to utilize such an approach.

B. Trading and Averaging Must Be Included in Any Final Guidelines and Should Be Encouraged as a Compliance Pathway.

EPA proposes to allow states to include an array of compliance flexibilities in compliance plans, including mass- and rate-based approaches, along with ability for states to use trading and averaging for compliance. Specifically, EPA notes that states can consider using mass- and rate-based trading programs in a way that "preserves the stringency of" the emissions limits that are

[260] *See* EEI's November, 2022 submission to EPA's non-regulatory docket. States routinely use mass-based limits when permitting new NGCCs under the PSD Program.

based on the identified BSER, and that these approaches should be consistent with other EPA trading programs, like the NOx Budget Trading Program, the Good Neighbor Rule, and others. *See* 88 *Fed. Reg.* at 33,393.

EPA notes that states should consider ways to ensure that any emissions budget does not overestimate the required budgets, including via a dynamic budgeting mechanism. *See id*. The Agency also notes that states could consider banking and/or averaging, as appropriate, which could help to incentivize unit retirements in advance of certain retirement deadlines. EPA proactively takes comment on whether to allow trading and averaging approaches as part of these guidelines. *See id*. at 33,395-96.

EPA should note in any final rule that trading and averaging are proven, well-understood approaches to compliance with environmental requirements and should affirmatively allow for these approaches to be included in state compliance plans. Allowing states to adopt a mass-based approach would also dovetail with the ability to utilize trading programs, and EPA should affirmatively note that both approaches are authorized. EPA should also consider developing a model trading program for states without the resources to develop their own plans or provide guidance to states about factors to consider when developing trading and averaging schemes as part of state plan development. Additional guidance or a model rule that states could adopt will assist with states developing plans in the two-year window provided for the state plan development process, and EPA should strive to release that guidance in conjunction with—or shortly after—any final rule. At a minimum, EPA should convene technical workshops with

interested stakeholders regarding the development of any trading regimes by states, to allow for increased coordination and collaboration through the development of state plans.

EPA has ample authority to permit states to use these approaches. Trading is not inconsistent with the recent Supreme Court decision in *West Virginia*. In that case, the Supreme Court suggested that if an overall cap (as defined by BSER) is based on "the application of particular controls and sources could have complied by installing them," emissions credit trading may be permissible as a compliance measure. *West Virginia,* Slip Op. at 21-22.

This also would be consistent with positions that EPA has taken in previous rules, in which the Agency has argued for significant compliance flexibility as a legal matter. The Agency's 1995 rule promulgating municipal waste combustor (MWC) emissions guidelines which allowed state plans the *option* to average emissions from units within a large MWC plant and to trade emissions credits between MWC plants. [261] In doing so, however, EPA set emission limits for averaging that were about 10 percent lower than if these limits applied to an individual plant.

In 2005, EPA issued the Clean Air Mercury Rule (CAMR) under CAA section 111(d), capping mercury emissions from coal-fired power plants. There, EPA first determined that technological systems were available to control mercury, but that it would take multiple years to install such controls across the existing fleet. CAMR's cap-and-trade system (allowing at least some affected sources to avoid installing technological controls) was based on EPA's determinations that such a

[261] *See Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources; Municipal Waste Combustors*, 60 *Fed. Reg.* 65,387 (Dec. 19, 1995).

system would: (a) constitute a "standard"; (b) reflect the degree of emissions limitation achievable; and (c) for coal-based EGUs, constitute BSER. *See* 70 *Fed. Reg.* at 28,616-17. Under CAMR, states had the option of adopting "substantially similar" regulations, but if they adopted other standards, EPA indicated that it would review the state plans pursuant to the 40 C.F.R. 60.24(h)(2)-(5).[262]

Further, as part of the briefing surrounding both the CPP and the ACE Rule, the D.C. Circuit's 2021 decision in *American Lung Association* found that EPA's limitation in the ACE Rule on the compliance measures that sources could use to comply with the states' standards of performance was arbitrary. *American Lung Association*, 985 F.3d 914, 957. EPA had categorically excluded two specific measures from the states' consideration: averaging and trading, and biomass co-firing. The Agency's concern was that compliance measures that are not source-specific could result in "asymmetrical regulation[,]" meaning the stringency of standards could vary across sources.[263] The D.C. Circuit found these concerns unpersuasive.

Because the court held that the EPA erred by concluding that CAA section 111(d) unambiguously required that BSER be source specific, the court noted that it must "necessarily reject the ACE Rule's exclusion … of compliance measures it characterizes as non-source-

[262] This criterion was subsequently deleted from the C.F.R. following vacatur of CAMR. The D.C. Circuit in *New Jersey v. EPA,* 517 F. 3d 574 (D.C. Cir. 2008), however, did not reach the merits of EPA's interpretation of its CAA section 111(d) authority; rather, the court determined that EPA had improperly "de-listed" the source category from CAA section 112, thus invalidating EPA's attempt to regulate under section 111.

[263] *See Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating units; Revisions to Emission Guidelines Implementing Regulations*, 84 *Fed. Reg.* at 32,520 (July 8, 2019) at 32,556.

specific." *Id.* at 957. The court also noted that even if EPA might reasonably limit compliance measures in specific situations based on its determination of the best system for reducing particular types of emissions with localized consequences, the statute imposes no requirement that such limitations be uniform across the regulation of different pollutants—in effect, there is no requirement for "symmetry" in regulation between standard setting and compliance. "Regardless of any policy-based reasons the EPA offers for limiting compliance measures, then, its decision to exclude averaging and trading and biomass co-firing is foreclosed by its legally erroneous starting point." *Id*.

None of these provisions were addressed directly by the Supreme Court's *West Virginia* decision, which focused exclusively on the major questions doctrine and focused mostly on the authority underlying the BSER determination made by the agency in the Clean Power Plan. As a result, that decision does not limit EPA's authority to offer states and affected sources broad compliance flexibility within an existing unit context. EPA should affirmatively and proactively offer states the ability to utilize trading and averaging approaches and should provide states with latitude to implement those approaches in a manner consistent with the need for both reliable system operations and the overall emissions reductions expected from a state plan under the final existing source guidelines.

C. Dual Path Options Should be Available for All Existing Sources and EPA Should Further Develop This Approach.

EPA explains, and as discussed above in section II of these comments, under the emissions guidelines for existing coal-based steam generating units in the Proposed 111 Rule states would place affected coal-based EGUs into one of four subcategories based on the time horizons over which those EGUs elect to operate. *See* 88 *Fed. Reg.* at 33,403. The Agency explains further that

these subcategories are static—that is, affected EGUs would not be able move between subcategories absent a plan revision. *See id.*[264] However, EPA does solicit comment on a dual-path approach for existing coal-based EGUs. Under such an approach, if included in any final rule, existing coal-based EGUs could submit two different standards of performance to EPA to be included in its compliance plan. *See id.* at 33,405. For example, for an affected coal-based steam unit that wants the option to be part of either the long-term or imminent-term subcategory, the state plan would include an enforceable standard of performance based on implementation of CCS and associated requirements, including increments of progress; as well as an enforceable requirement to permanently cease operations before January 1, 2032, and a standard of performance based on routine operation and maintenance. *Id.*

EPA should, at a minimum, further develop this dual-path approach and include it in any final rule, which would allow for states and sources to take full advantage of EPA's proposed subcategories. Compliance and operations decisions regarding EGUs are complex and involve multiple steps over which owners and operators may have varying levels of control, including integrated requirements to decommission a unit, procure replacement generation, meet capacity requirements, and—in the event of a unit working to comply with several of the compliance pathways chosen by EPA, including potentially the installation of CCS—procurement, design, and installation of control technology, including the need to permit and test any new technology. A proposed path may seem viable during the state plan development phase, but soon after can become unworkable or infeasible. A dual-path approach would allow owners/operators and states

[264] As discussed further *infra*, EPA should consider providing greater flexibility for units to move between subcategories during the compliance period based on a variety of factors.

additional time to make these difficult and complex decisions, while also providing additional flexibility to account for potential changes in circumstances, including delays in procuring, or more expedited arrival of, replacement generation, or reliability considerations. Accordingly, EPA should include dual-path optionality in the final rule.

The Agency also should allow existing coal-based EGUs the opportunity to select a dual-path approach for units that might retire as part of one of the proposed subcategories, but also should permit these units the option to convert completely to steam-gas units that comply with the steam-gas rate limitations proposed by EPA. This would allow units to either retire or convert, resulting in significant emission reductions under either approach, consistent with EPA's rationale for providing dual-path approaches.

D. EPA Should Alter Its Proposed Approach to Increments of Progress to be Consistent with Providing Appropriate Flexibility to States and Units.

EPA is proposing to adopt emission guideline-specific implementation of the five generic increments specified in the CAA section 111(d) implementing regulations. These five increments of progress are: (1) Submittal of a final control plan for the designated facility to the appropriate air pollution control agency; (2) Awarding of contracts for emission control systems or for process modifications, or issuance of orders for the purchase of component parts to accomplish emission control or process modification; (3) Initiation of on-site construction or installation of emission control equipment or process change; (4) Completion of on-site construction or installation of emission control equipment or process change; and (5) Final compliance. 88 *Fed. Reg.* 33,388. EPA also proposes that state plans must include specified enforceable increments of progress as required elements for coal-based EGUs that use natural gas co-firing to meet the standard of performance for the medium-term existing coal-based steam generating subcategory

and for natural gas-based combustion turbine EGUs that use hydrogen blending to meet the standard of performance. *Id*.

EPA has clear authority to require increments of progress under the statute and its own regulations; however, EPA should not be overly prescriptive in setting those increments of progress so that the only method of implementing or complying with those increments for the medium-term coal-based subcategory or hydrogen pathway for combustion turbines is how units must comply with EPA's specific BSER. As noted *supra*, the D.C. Circuit's decision in *American Lung Association* notes that EPA could offer significant compliance flexibility to states and units and was not required to have sources implement the specific BSER prescribed by EPA. *American Lung Association* 985 F.3d at 942-43, 96. As proposed, the increments of progress—especially (3) Initiation of on-site construction or installation of emission control equipment or process change, and (4) Completion of on-sites construction or installation of emission control equipment or process change—seem to denote that sources in these subcategories *must* implement EPA's BSER to comply with the increments. EPA should note that sources do not have to meet every single increment of progress, especially if those sources are part of a broader mass-based, trading, averaging, or other compliance approach that does result in an emission limitation being placed on an individual unit. Such an approach would be consistent with offering additional flexibility to sates and units, as well as *American Lung*.

The Agency also notes that it is not proposing increments of progress for either the imminent- or near-term subcategories for coal-fired steam generating units, or for oil- or natural gas-fired steam generating units. The proposed BSERs for these affected EGUs are routine operation and

maintenance. *See* 88 *Fed. Reg.* 33,388. Given that these units are utilizing routine operation and maintenance as BSER, such an approach is warranted and valid. EPA should finalize this approach.

E. EPA Should Provide Additional Guidance Regarding Setting Unit-Specific Baselines.

In Section XII(D)(1)(a) of the preamble to the Proposed 111 Rules, EPA describes its proposed method for states to determine the baseline emissions performance, which is a critical step in determining the presumptive standards for existing EGUs. *See* 88 *Fed. Reg.* 33,240, 33,375 (May 23, 2023). Once a state determines a unit-specific baseline, it will then "apply" the BSER to that unit based on which BSER is applicable to that unit, resulting in a unit-specific emissions rate.

While states have the obligation to set unit-specific emissions limitations for each existing affected fossil-based generator, EPA proposes presumptive methods for establishing emissions limitations for certain subcategories of these units, and state plans that opt to use this methodology to calculate emissions rates would be presumptively approvable. The proposed methodologies both account for historic unit-specific operations—on the assumption that past performance is indicative of future performance—and EPA's proposed BSER for the relevant subcategory. After identifying the affected EGUs in the state, EPA proposes that the state would then use the corresponding methodology for the given subcategory to calculate and then apply the presumptively approvable standard of performance for each affected EGU. The Agency notes that the proposed approach would provide a "uniform" way to determine unit-specific standards while allowing unit owners and operators to be able to reasonably approximate the emissions limitations that would apply to units prior to the development of state plans. *See* 88 *Fed. Reg.* 33,358.

EPA's proposed methodology is that a state will use the CO_2 mass emissions and corresponding electricity generation data for a given affected unit from any continuous eight-quarter period, from 40 C.F.R. part 75 reporting, within the five years immediately prior to the date the final rule is published in the Federal Register. EPA expects states to utilize the most representative eight-quarter period of data from those five years. *See id*. EPA will evaluate the choice states' determination of what constitutes representative data when reviewing state plan submissions. However, the Agency notes that it intends to defer to a state's reasonable exercise of discretion as to which 8 quarter period is representative. *See id*. at 33,375. For example, a state establishing baseline emission performance in the year 2023 would start by evaluating the CO_2 emissions and electricity generation data for each of its affected EGUs from 2018 through 2023. The state would choose a continuous eight-quarter period that it deems to be the best representation of the operation for each affected EGU. *See id*.

Using these eight quarters of data, the state would then divide the total CO_2 emissions (in the form of pounds) from that continuous time period by the total gross electricity generation (in the form of MWh) over that same time period. This result is baseline CO_2 emission performance in lb CO_2 per MWh. *See id*. States would then multiply that baseline rate by the emissions reductions EPA has determined is achievable via the application of the BSER for the relevant subcategory to determine the presumptively approvable emissions limit for that unit. *See id*. For example, if an existing natural gas combined cycle unit had a baseline emissions rate of 1000 lb CO_2/MWh, the resulting emissions limitation (effective starting in 2035) would be 110 lb CO_2/MWh, reflecting EPA's determination that carbon capture and sequestration (CCS) at a 90

percent capture rate would result in an 89 percent reduction in emissions (1000 x .11 = 110). These are baseline calculations and are not necessarily the way compliance is demonstrated.[265]

EPA also notes that, consistent with CAA section 111(d), states retain the ability to deviate from EPA's proposed methodology to apply more stringent standards. *See id*. However, EPA believes that the instances in which a state may need to use an alternate baseline-setting methodology will be limited to anticipated changes in operation, such as circumstances in which historical emissions performance is not representative of future emissions performance.[266] Where such changes result in a less stringent standard of performance, states must use the remaining useful life (RULOF) mechanism to determine the appropriate emissions limitation, which is discussed at length *infra* in these comments.[267] *See* 88 *Fed. Reg.* at 33,381.

The flexibilities EPA provides around setting unit specific baselines are well founded. The latitude provided by EPA both for states to determine which eight quarters are best representative and to use another methodology if they choose will allow for more accurate baseline determinations for EGUs. However, to simplify how the methodology is administered and ensure

[265] EPA proposes that: coal or gas units applying CCS at a 90 percent capture rate results in approximately an 89 percent reduction in emissions rate; coal units that are co-firing with 40 percent natural gas results in an 18 percent reduction in emissions rate; gas units blending hydrogen at 30percent by volume results in a 12% reduction in emissions rate; gas units blending hydrogen at 96 percent by volume results in an 89 percent reduction in emissions rate. EPA does not delineate the expected emissions rate reduction from a 20 percent capacity factor restriction for coal units.

[266] For example: a state decides that an EGU in the medium-term coal-fired subcategory should co-fire 50 percent natural gas instead of 40 percent.

[267] RULOF is discussed in more detail in Section VI(H), *infra*, and also *supra* in Section II regarding EPA's authority to utilize retirement-abased subcategories.

consistency and predictability for state and unit owners/operators, in the final rule or through guidance, EPA should provide several examples states can use as templates for making these determinations. Some of these are included in the Proposed Rule, but additional examples and variations should be included in any final rule. This will ensure that unit owners and operators have a better sense of the manner in which states may exercise their discretion in making these determinations.

Further, EPA should provide additional clarity surrounding how to address baseline calculations for coal-based units that are already co-firing with natural gas or have existing capacity factor restrictions as these units do not fit perfectly into the proposed methodology, which assumes that units have not implemented any restrictions that impact their emissions profile. EPA should provide additional clarity and specific guidance for how to address and account for these variations from EPA's assumed baseline methodology.

F. EPA Should Provide More Flexibility in Implementing Its Proposed Remaining Useful Life and Other Factors (RULOF) Provisions When Assessing State Plans.

EPA's approach to states' ability to engage in RULOF analyses as part of their obligation to set standards for existing units is inflexible and does not comport with the role afforded states under section 111(d)(2).[268] EPA is obligated, therefore, to provide more flexibility for states to consider

[268] As discussed in section II, EPA should cite section 111(d)(2)'s authorization for states to consider remaining useful life and other factors as an alternative rationale to support the legality of the proposed retirement subcategories for existing coal-based units, which would be in line with a more flexible and expansive approach to the RULOF requirements in the statute. These proposed subcategories are an appropriate exercise of EPA's statutory authorization to distinguish between classes, types, and sizes of units when setting standards; but, they also represent a presumptively approvable approach to a state's exercise of its discretion to consider remaining useful life and other factors when setting standards for these existing units. EPA

using RULOF to modify the presumptive standards for an affected facility. EPA can assess the validity of the RULOF analysis and resulting standard when determining whether to approve a state implementation plan. To ensure that states can consider RULOF when setting standards for existing units, EPA should clarify in any final guidelines that states are not limited in the ways that EPA proposes, but instead are free to make such demonstrations as appropriate. In addition, EPA also should provide guidance on how states could rely on cost assumptions and source-specific considerations that may differ from approaches EPA has taken.

1. EPA must provide more flexibility to states to consider RULOF when setting standards for existing units.

EPA proposes that a state's invocation of RULOF when setting a standard for any existing unit would be required to be based on one or more of three circumstances—(1) unreasonable cost of control resulting from plant age, location, or basic process design; (2) physical impossibility or technical infeasibility of installing necessary control equipment; and (3) other facility-specific circumstances that are fundamentally different from the information considered in determining the BSER—and that there must be "fundamental differences" between the EPA's determined BSER and the circumstance of affected EGU. *See* 88 *Fed. Reg.* at 33,382.

While these criteria are generally reasonable, their proposed application is both unreasonably stringent and requires further guidance. EPA may "not anticipate that states would be likely to demonstrate the need to invoke RULOF based on a particular coal-fired EGU's remaining useful life," and may believe that the circumstances for properly invoking RULOF "will be rare," but

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should adopt this approach and also adopt a more expansive individual-unit RULOF approach as well.

EPA must consider a wide range of approaches for a state's proposed use of RULOF. *Id.* at 33,383-84.

EPA also proposes that states wanting to invoke RULOF must also consider cost in terms $/ton of CO_2 reduced and $/MWh electricity generated. *See* 88 *Fed. Reg.* at 33,382. EPA should be less prescriptive. While EPA may have considered $/ton of CO_2 reduced and $/MWh electricity generated in determining BSER, an identical requirement for states in crafting plans is not justified or necessary since states can consider the unique circumstances of each unit and the attendant costs, as long as each state plan provides a justification of the costs it considers as part of invoking RULOF for a specific source. Instead, EPA can note that such costs metrics can be helpful in supporting a standard that is based on a state's RULOF assessment, but EPA cannot deem that any deviation from this cost metric is fatal for the resulting standard.[269] Ultimately, EPA should examine a state's invocation of RULOF in a more holistic sense and consider why the state is proposing a different standard than those deemed presumptively approvable by EPA for an affected EGU.

If a state relies on "unreasonable cost of controls" in support of invoking RULOF, EPA proposes to require that states must demonstrate the facility cannot reasonably apply the BSER to achieve

[269] Moreover, EPA's reliance on the cost of carbon abatement is not a relevant or appropriate metric for determining BSER, nor is it relevant for a RULOF determination. Owners/operators of affected units, and states, need to consider the cost of the potential controls relative to the remaining useful life in determining whether it is reasonable to apply the BSER in determining a standard of performance or to invoke RULOF. The cost of carbon abatement is not an appropriate substitute for the actual cost impacts on a per unit basis. It can be useful for comparative analysis, but it bears little relationship to the costs that companies and their customers may have to bear to achieve compliance.

the emissions limitation determined by EPA, including that there must be a "fundamental difference" between EPA's BSER and the circumstance of affected EGU. EPA seeks comment on whether it should provide further guidance for determining when costs are "fundamentally different" from EPA's BSER determination. *See id*. EPA outlines some of the considerations taken into account in determining the BSER, including the physical possibility and technical feasibility of applying that system, the costs of a system of emission reduction, the non-air quality health and environmental impacts and energy requirements associated with a system of emission reduction and the extent of emission reductions from a system. *See id.* EPA further notes that "many of the factors [it] considers in its BSER determination," which would be the same or similar to the factors a state would consider in invoking RULOF, "are reflected in the cost considerations" for determining the standards of performance. EPA also provides examples of costs, including for CCS and natural gas co-firing for coal-based EGUs, that it evaluated in determining the proposed standards of performance. *See id*.

While this guidance generally may be helpful to states, it is nonetheless incomplete and largely provides examples of how difficult EPA believes it should be to demonstrate the required fundamental difference in cost. EPA should provide additional guidance on how states can show that the costs of controls is unreasonable, including examples of what would be considered an adequate demonstration of different costs from EPA's BSER determination for an affected EGU. EPA should also eliminate the modifier "fundamental," as it is not defined and is intended to limit states' exercise of RULOF to set different standards for certain existing units. EPA can assess the sufficiency of any cost differences demonstration based on the record before it in any

proposed state implementation plan. EPA should avoid prejudging the outcome of its own assessment in this way.

The other two circumstances EPA cites under which invocation of RULOF could be based—physical impossibility or technical infeasibility of installing necessary control equipment, and other facility-specific circumstances that are fundamentally different from the information considered in determining the BSER—are reasonable and applied logically. For example, "facility-specific" circumstances could include the situation where replacement generation is not available in time for the affected facility to retire as scheduled. EPA provides helpful examples of how these circumstances could be applied to an affected EGU in considering the use of CCS, or to an affected combustion turbine in considering the amortization period for controls when deciding to cease operations and make that closure enforceable. *See id*. at 33,383. EPA also correctly proposes to allow states to use RULOF to provide a different compliance deadline for sources that can meet the standard of performance but not by the final compliance date under these guidelines. As discussed elsewhere in these comments, states should be able to use RULOF to adjust compliance deadlines, including the compliance deadlines included in EPA's presumptively approvable proposed retirement subcategories.

2. EPA should provide additional guidance to states on potentially approvable RULOF approaches.

EPA provides additional guidance as to potential specific invocations of RULOF by states when setting standards of existing units. EPA proposes that states invoking RULOF for affected coal-based units in the long-term coal-based retirement subcategory be required to evaluate natural gas co-firing as a potential source-specific BSER. States invoking RULOF for affected long-term (and medium-term) coal-based EGUs must evaluate different levels of natural gas co-firing

unless they have demonstrated that natural gas co-firing at any level is physically impossible or technically infeasible at the source. *See* 88 *Fed. Reg.* 33,384. Additionally, if an EGU in this subcategory can implement CCS but cannot achieve the degree of emission limitation prescribed by the BSER, EPA proposes that the state evaluate CCS with a source-specific degree of emission limitation. *See id.* For natural gas-based units choosing the CCS or hydrogen blending pathways, states would first have to demonstrate that the affected EGU cannot reasonably participate in the other pathway and meet that pathway's presumptive standard. "If a unit can comply it must do so." *Id.* at 33,385. For natural gas-based units opting for the CCS compliance pathway, EPA proposes that if a unit cannot reasonably comply with either of the performance standards—unless a state has demonstrated that it is physically impossible or technically infeasible for a unit to implement CCS—that the state must evaluate CCS with lower rates of carbon capture as a potential BSER. If CCS with lower rates of capture is not the BSER, then states would be required to consider comprehensive turbine upgrades, and finally smaller scale efficiency improvements. *See id*. For natural gas-based units in the hydrogen pathway that cannot reasonably comply with the performance standards for either category, EPA would require that states first analyze lower percentages of hydrogen co-firing, followed by comprehensive turbine upgrades and, lastly, smaller scale efficiency improvements. *See id*. While these requirements for specific instances in which a state might invoke RULOF, the Agency should also allow states more flexibility for determining source-specific BSER and calculating a standard of performance for affected EGUs.

Rather than limiting states' ability to invoke RULOF in these scenarios, EPA instead should characterize these as presumptively approvable approaches. This will provide states with greater

flexibility in developing state plans and evaluating the invocation of RULOF for affected EGUs while ensuring that states take the necessary steps for determining an applicable standard of performance for affected EGUs.

This flexibility is consistent with other aspects of EPA's proposed approach to RULOP. For example, EPA proposes that states invoking RULOF for affected long-term and medium-term coal-based units must evaluate different levels of natural gas co-firing if an affected EGU cannot reasonably co-fire 40 percent natural gas unless the state has demonstrated that natural gas co-firing at any level is physically impossible or technically infeasible at the source. Similarly, states seeking to invoke RULOF for affected CTs must evaluate CCS with lower rates of carbon capture or hydrogen co-firing as a potential BSER. *See* 88 *Fed. Reg*. at 33,385. Such an approach to applying RULOF is reasonable, and EPA should allow states to take a flexible approach in evaluating what might be an appropriate level of co-firing.

3. EPA's proposed additional requirements for sources invoking RULOF are appropriate.

EPA also proposes three additional provisions for states seeking to apply less stringent standards of performance pursuant to RULOF. One requires state plans to consider the potential pollution impacts, and benefits of control, to communities most affected by and vulnerable to emissions from the affected EGU. In addition, state plans that include a less stringent standard of performance pursuant to RULOF must meet all other applicable requirements of subpart Ba and the proposed guidelines, including the use of site- and source-specific information when possible. The proposed rule would also allow states to adopt and enforce standards of performance more stringent than required by an applicable emissions guideline. *See id*. at 33,386-87. EPA's proposed implementation of the other three provisions for invoking RULOF

are reasonable and are in line with the Administration's Justice40 and related environmental justice initiatives.

G. Gas-Steam Units Require Additional Flexibilities.

EPA's proposed BSER for existing natural gas-fired steam generating units is "routine methods of operation and maintenance" and its proposed emissions limitation for these units is "no increase in emission rate (lb CO_2/MWh-gross)," presumptive unit limitations of either 1,300 lb CO_2/MWh, or 1,500 lb CO_2/MWh based on unit capacity factor. For low load existing natural gas-fired steam generating units, EPA neither proposes BSER nor emissions limitations. These standards are well founded and should be finalized; allowing these units to continue to serve their vital grid function while retaining the emissions benefit of prior conversion to utilizing natural gas from coal is critical for system reliability and affordability. EPA's approach on gas-steam units is the correct one.

EPA should also provide additional clarity to make the standards for gas-steam units maximally useful for states and members. EPA can provide additional clarity on applicability between categories for units based on utilization. EPA should also clarify that units can utilize the presumptive unit limitations in lieu of the no increase in emission rate approach. The Agency should state that it is either the presumptive *or* the no increase in emission rate unit-specific standard. This flexibility is well-grounded in EPA's traditional approaches discussed *supra* in this section and should be included.

Further, as described in these comments *supra*, the electric industry is in the process of a clean energy transformation. EPA recognizes this reality in the Proposed Rule by offering

subcategories for retiring coal-based units. As part of the clean energy transformation, EEI's member companies also are continuing to retire certain natural gas-based units. EPA should develop and finalize retirement-based subcategories for these existing natural gas steam units, similar to those for coal-based units, in any final rule.

EPA should also be explicit in any final rule that coal-based units in retirement subcategories that later choose not to retire, but rather, completely convert to utilizing natural gas may transition to the standards for natural gas-based units. Unforeseen future circumstances—including potential reliability needs—may require that coal-based units slated for retirement instead convert to using natural gas rather than completely retire. EPA should account for these potential situations in any final rule by providing gas-steam units additional flexibilities.

H. Allowing States Additional Time to Submit Plans, and the Ability to Revise Plans After Submittal and During the Compliance Period, Is Essential.

In the preamble to the Proposed Rule, EPA notes that it expects to finalize the proposed standards for exiting units by June 2024. States will have 24 months to develop plans and will be required to submit these plans no later than June 2026. *See* 88 *Fed. Reg.* 33,401. EPA notes that it will adjust this deadline to reflect the actual date that standards are finalized; regardless of that date, states will have 24 months to develop and submit plans. States will have to meet a number of requirements as they develop plans, including requirements for public hearings, provide supporting documentation, and other completeness requirements. EPA notes that this is an increase in time from the current regulatory requirement for states to submit plans within 9 months of a final existing source guideline, and the Agency's December 2022 proposal to allow for up to 15 months for states to submit plans under proposed changes to the section 111 implementing regulations. *See id*.

EPA also acknowledges that, despite states' best efforts to accurately reflect the plans of owners/operators regarding affected EGUs at the time of state plan submission, such plans may subsequently change. *See* 88 *Fed. Reg.* 33,403. The Agency, therefore, reiterates that states have the authority and discretion to submit revised state plans to EPA for approval under 40 C.F.R. 60.23(a)(2), 60.28(a). *See id.*

EPA is justified in providing states with additional time to develop and submit plans to EPA beyond the nine months allowed by the generic section 111 implementing regulations and the 15 months in the proposed updates to those implementing regulations. The Agency should allow for at least the 24 months proposed for states to develop and submit plans given all the required steps—some of which are described above—to apply individual, unit-specific emissions rates to the vast number of sources covered by the proposed existing source guidelines in the Proposed 111 Rules. However, it is unclear if this is enough time for all states to develop and submit plans given the tremendous workload successful plan development requires, and EPA should either provide more time for initial plan development or provide significant mechanisms to extend the submission deadline for state plans. To the extent that states are unable to fully submit a plan to EPA for approval within those 24 months—but are working to develop and submit a plan to EPA—the Agency should develop and finalize a mechanism to provide an additional 12 months to finalize and submit a plan, and such a mechanism should be based on concrete steps that can be triggered automatically through specific, easy to understand and demonstrate criteria. EPA should explicitly consider what milestones will be required for states that need this additional time, which could include plans being out for comment, or state legislative changes that must be

completed, and/or other tangible, specific events or requirements. This is appropriate given the potentially large number of existing coal- and natural gas-based units in some states.

Continuing to allow states the flexibility to revise plans after initial submittal, as already provided in the regulations, will help states and owners/operators of EGUs address new and unforeseen circumstances, including reliability, load growth, and technology deployment. At a minimum, and to ensure efficient and effective processes, EPA should commit to reviewing and making decisions on revised state plans expeditiously. EPA also should consider allowing states to reclassify units based on new and emerging events or circumstances without needing to go through a formal or total plan revision. This would increase the efficiency and efficacy of state plans but would also have another practical effect: namely the state plan revision and EPA approval process, even done as expeditiously as possible, is time consuming. Implementing some of the choices that will be included in state plans, especially given the lead times for permitting changes or installation of control technology, or natural gas co-firing capabilities, will require significant lead times. As decisions and circumstances change throughout the period after plans are filed, responding to potentially changing circumstances without the burden of additional regulatory time through a plan revision will benefit states, units, and EPA by avoiding time consuming and resource-intensive processes.

I. EPA Should Seek to Approve Existing State Programs as Much as Possible.

In the preamble to the Proposed 111 Rules, EPA explains that many states have adopted binding policies and programs under their own authorities that have significantly reduced, and will continue to reduce, CO_2 emissions from EGUs. *See* 88 *Fed. Reg.* at 33,396. These programs

include multi-state and regional programs, such as the Regional Greenhouse Gas Initiative (RGGI).[270]

The scope and approach of EPA's Proposed 111 Rules can differ significantly from the range of policies and programs employed by states to reduce power sector CO_2 emissions, notably applying to a narrower subset of EGUs within the broader electric power sector. However, there still may be significant cross-over between the Proposed Rule and myriad state programs. In any final rule, EPA should signal it intends to approve appropriate existing state programs in a manner that avoids potential regulatory duplication. This would increase efficiency, reduce duplicative and/or potentially conflicting regulations between the state and federal level, and improve cost-effectiveness for owners/operators and customers. To the extent that existing state programs, even if they are set up differently and utilize alternative mechanisms for compliance and enforceability, can achieve equivalent reductions as those that would be achieved by unit-specific standards, satisfying the broader emissions reductions goals of CAA section 111, EPA should seek to approve those programs. This includes states that use a variety of other low-GHG "drop in" or replacement fuels in turbines, including biogas, renewable natural gas, ammonia, and other types of low-GHG fuels that provide significant life cycle carbon benefits while allowing companies to continue to utilize existing and new turbines to provide grid services. States should be able to utilize them as part of state plans since several states utilize these fuels as part of their existing frameworks.

[270] RGGI, https://RGGI.org (2023).

At a minimum, EPA should clarify which elements of existing state plans may be presumptively approvable, or what additional analysis and justification states would need to provide in order to have EPA approve a state plan including such programs. EPA also can provide additional avenues for existing programs to be approvable by providing additional compliance flexibilities more generally—including explicitly authorizing the use of mass-based approaches, trading, averaging, and others—to the states as discussed *supra*.

J. EPA Should Provide Clarity Regarding the Definition of System Emergency.

EPA proposes to amend the definition of system emergency in 40 C.F.R part 60, subpart TTTT and the proposed 40 CFR part 60, subpart TTTTa. That definition includes a provision that electricity sold during hours of operation when a unit is called upon to operate due to a system emergency is not counted toward the percentage electric sales subcategorization threshold. *See* 88 *Fed. Reg.* at 33,333. In the past, EPA concluded that an exclusion was necessary to provide flexibility, to maintain system reliability, and to minimize overall costs to the sector. *See* 80 *Fed. Reg.* 64,612. EPA notes that the intent of that the local grid operator would determine which EGUs are essential to maintain grid reliability, and it solicits comment on whether to amend the definition of system emergency to clarify how the intent of the grid operator standard would be implemented. *See id*.

The current regulatory definition of system emergency is that any "abnormal system condition" that the RTO/ISO or control area administrator determines requires immediate automatic or manual action to "prevent or limit loss of transmission facilities or generators that could adversely affect the reliability of the power system" and therefore call for maximum generation resources to operate in the affected area, or for the specific affected EGU to operate to avert loss

of load. The emissions from units that are called on during these "abnormal system condition" would not count towards the compliance calculation for any individual unit, per EPA. 88 *Fed. Reg*. 33,333-34.

EPA should keep this provision and provide additional specificity as to what constitutes an "abnormal system condition." EPA should consider using an emergency alert level 2, which is when an RTO/ISO or local balancing authority requests emergency energy from all resources and has activated its emergency demand response program. During an emergency alert level 2, consumers are urged to conserve energy to help preserve grid reliability. This level precedes alert levels 3 and 4, which occur when a grid operator is unable to meet minimum reliability reserve requirements and then rotating power outages begin occurring to preserve grid reliability broadly, respectively. All units operating when an emergency alert level 2 is declared are working to prevent the abnormal system condition included in EPA's definition, and EPA should affirmatively note that those emissions should not negatively impact a unit's compliance.

Further, since emergency alert levels impact the entire grid, EPA should allow this definition for all existing coal- and natural gas-based units; when a grid operator or balancing authority calls on units under an emergency alert level 2, it does not discriminate on which units will be called on; as a result, EPA should ensure that all types of units, not just Subpart TTTT or Subpart TTTTa units have the ability to access this provision in the regulations. Such an approach would help allow units and system operators additional certainty in responding to any reliability events or issues.

VI. EPA Should Clarify Applicability Requirements Across All Three Rulemakings.

EPA should clarify applicability across all three substantive rulemakings to provide specific direction regarding which set of standards could apply to units. The requested clarifications are discussed below.

A. EPA Must Clarify Applicability for Existing Coal-Based EGUs.

For existing coal-based units, EPA appears to allow states and unit owners/operators choose among the various retirement subcategories. However, once a selection is made, and the retirement comments are made federally enforceable via its inclusion in an approved state plan, it is not clear how changes to the planned retirement date could be effectuated. EPA should clarify how units might move between categories to address changing conditions to accommodate both earlier and later retirements.

As a corollary, and as discussed *supra*, EPA should simplify the increments of progress requirements to maximize the potential for units to move between subcategories. There is the possibility that the increments of progress and/or milestone requirements, as proposed, could limit the ability to change subcategory classification.

EPA also proposes an applicability definition of "coal-fired steam generating unit" in proposed section 60.5880b holding that the existing source guidelines apply to any unit that meets the definition of "fossil fuel-fired" and that burns coal for more than 10.0 percent of the average annual heat input during the three calendar years prior to January 1, 2030, or for more than 15.0 percent of the annual heat input during any one of those calendar years, or that retains the capability to fire coal after December 31, 2029. This look back provision for units to be "coal-

fired steam generating units" based on their heat input in years 2027- 2029 may be overly restrictive, as units that could convert to steam-gas units or utilize alternative fuels might be able to do so prior to 2030. EPA's proposed definition, however, essentially mandates that those conversions occur by 2027 (or maybe 2028, depending on unit operations) to avoid being classified as a coal-fired steam generating units. This may impede units from reducing emissions by switching fuels and could act as an incentive to continue the use of coal as opposed to investing in the development of other fuels, like natural gas or biomass. EPA should make it clear that this applicability element does not apply to any unit that makes such a conversation prior to 2030.

B. EPA Must Clarify Applicability for New and Existing Natural Gas-Based Turbines.

The Agency also should clarify applicability requirements for new natural-gas based units, particularly between intermediate and low-load units, but also across all three standards phases. As discussed, *supra*, the capacity factor restriction requirements in the Agency's proposed NSPS for gas-based units is a complex, unit-specific inquiry based on heating value and overall capacity factor. Given the widely varying requirements in terms of emissions rates and potentially phased standards for new gas-based units, EPA needs to provide clarity around how units are determined to be low load, intermediate load or base load. In particular, the Agency should provide clarity regarding the demarcation between the low and intermediate load natural gas-based units, since intermediate-load units would be subject to potential phased standards including hydrogen blending while the low-load units would not have the same requirements. *See* 88 *Fed. Reg.* 33,244. As currently proposed, it is not clear how applicability of sources would function as a practical matter with compliance—e.g., applicability for each subcategory is determined on an annual basis on a unit-by-unit analysis, while compliance with EPA's standard

for new units is measured on a 12-month rolling average. EPA should address this discrepancy and provide clarity regarding how applicability and compliance can be synchronized in order for sources to practically comply with EPA's standards.[271]

Finally, EPA should clarify to which existing natural gas-based units the Agency's proposal applies. EPA proposes that the existing source guidelines would apply to "large (*i.e.,* greater than 300 MW), frequently operated (*i.e.,* with a capacity factor of greater than 50 percent), existing … stationary combustion turbines." *Id*. at 33,245. EPA should state that the determination of whether a unit is subject to regulation under the proposed standards is based on actual utilization greater than 50 percent capacity factor, and not a unit's ability to operate at capacity factors of at least 50 percent. If applicability is based on ability to operate at capacity factors of at least 50 percent, the proposed standards would apply to a much larger subset of units as ability to operate is much greater than actual operations. EPA's intent appears to have been to take a more limited approach to applicability and should thus make the requested clarification as it is consistent with EPA's approach.

More importantly, EPA must specify whether the determination of the applicable subcategory for an existing natural gas-based turbine is a one-time test or whether there would there be an ongoing obligation to evaluate the annual capacity factor and potentially reclassify a unit if the capacity factor changes such that a different subcategory would apply. Constant re-evaluation

[271] EPA also proposes to exempt EGUs "not capable of combusting natural gas (e.g., not connected to a natural gas pipeline)" as part of its proposal at 40 C.F.R. section 60.5509(b)(8). This exemption is well founded and warranted, especially for EEI members that cannot be connected to a natural gas system, like those in isolated or island locations. EPA should retain and finalize this provision.

would be labor intensive for unit owners/operators and the state air quality regulators who would be required to make such assessments. It also would provide little operating certainty. Accordingly, EPA should take the approach that applicability determinations are final once made or, at minimum, should leave such determination up to the discretion of the state regulator.

VII. Conclusion.

EEI Looks forward to working with EPA to finalize a defensible and implementable set of section 111 rulemakings. The Proposed 111 Rules are an important piece of the regulatory framework that can either support or hinder the power sector's continuing clean energy transformation. EPA must ensure that the Proposed 111 Rules work on their own, work with each other, work with the rest of EPA's holistic approach to regulation, and—critically—work within the entire regulatory, legislative and economic context within which the power sector operates at the federal and state levels. EEI appreciates the engagement with EPA staff regarding this rulemaking. Questions on these comments may be directed to Alex Bond (202-508-5523).