Comments of Duke Energy on the:

New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule

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I. Introduction

Duke Energy appreciates the opportunity to comment on the U.S. Environmental Protection Agency's (EPA) proposed greenhouse gas emissions standards for new and existing electric generating units (collectively, "proposed rule") under Section 111 of the Clean Air Act (CAA or "Act").

Duke Energy is one of the largest energy holding companies in the United States with a large, diversified portfolio of energy assets and services. We provide electricity to a growing customer base – currently 8.2 million retail customers in six states – and natural gas to over 1.6 million customers in five states. We operate a growing regulated renewable energy portfolio, 289,700 miles of distribution lines and a 31,500-mile transmission system.

We are leading one of the largest clean energy transformations in the U.S. and we have adopted ambitious goals for reducing carbon dioxide (CO_2 or "carbon") emissions from our electric generating fleet – to achieve a reduction of at least 50% below 2005 levels by 2030, to achieve an 80% reduction by 2040, and to achieve net-zero carbon emissions by 2050.[1] We also have a goal to achieve net-zero Scope 1 methane emissions from our natural gas business by 2030. Through 2022, our carbon emissions from electricity generation are 44% below 2005 levels, largely achieved through retiring 56 coal-fired electric generating units (EGUs) representing nearly 7,500 megawatts (MW) of capacity. Over the next few years, we plan to continue retiring coal units and project to generate less than 5% of our energy from coal by 2030. Our goal is to cease all our coal-fired generation by 2035.[2]

To accomplish these ambitious greenhouse gas emission reduction goals and continue to serve growing electricity demand, we are installing increasing amounts of new renewable generation on our system and project that we will own, operate, or contract for 30,000 MW of regulated wind and solar by 2035. This is five times more than we have on our system today. We also need to install additional clean-burning natural gas units to replace the dispatchable role coal plays to maintain grid reliability while new zero-carbon technologies are being developed and tested at scale. And we are leaning in to help develop and deploy the new dispatchable technologies that are needed to make the full clean energy transition while reliably meeting growing demand. These include hydrogen, carbon capture and storage/sequestration (CCS), long-duration energy storage, and new nuclear technologies.

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[1] Duke Energy has also adopted ambitious goals for reducing Scope 2 and certain Scope 3 greenhouse gas emissions – to achieve a 50% reduction below 2021 levels by 2035 and to achieve net-zero emissions by 2050. Taken together, Duke Energy's Scope 1, 2 and 3 goals cover more than 95% of reported 2021 emissions.

[2] Subject to state public utility commission regulatory approval and availability of replacement generation.

For hydrogen, in partnership with other utilities and technology developers, we have proposed a hydrogen hub in the Southeastern U.S. and are seeking federal funding support from the U.S. Department of Energy (DOE). We are also planning for a short-term solar-to-hydrogen pilot-scale demonstration at a natural gas combustion turbine in Florida; we expect this project to be operational in 2024. Duke Energy is also evaluating the feasibility of CCS within its service territory and, earlier in 2023, was selected by DOE for award negotiations on a Front-End Engineering Design (FEED) study at the company's integrated gasification combined cycle (IGCC) facility in Edwardsport, Indiana. Through these efforts and collaborations with leading clean-energy technology developers and manufacturers, Duke Energy has gained an extensive understanding of the state of development and requirements for deployment of hydrogen and CCS.

The company is also building on its strong base of carbon-free nuclear energy in the Carolinas and is looking to new nuclear technologies that have significant potential to perform as zero-emitting, load-following resources. We are evaluating light-water-cooled small modular reactors that are similar to the nuclear fleet operating today, and we are monitoring the development of leading advanced reactor technologies. The latter includes partnering with TerraPower and GE Hitachi on the development of an advanced reactor that integrates energy storage via a molten salt system.

We are also expanding our efforts to provide and help develop long-duration energy storage. For example, Duke Energy owns and operates the 1,600-MW Bad Creek pumped-storage hydroelectric plant in Oconee County, S.C. This plant currently has the ability to supply enough energy to power nearly 1 million homes. Bad Creek operates like a giant battery, storing energy when demand is low and quickly generating electricity when demand is high, thus balancing electricity supply and demand. We are nearing completion of the engineering work required to determine the feasibility of constructing a second powerhouse at Bad Creek, roughly doubling its current capacity. This powerhouse could be in service as early as 2033, assuming state regulatory approvals.

In addition, we currently have approximately 100 MW of battery storage in service or under construction and are planning for over 10,000 MW of energy storage capacity by 2035. This will include our long-serving hydroelectric assets, battery storage technologies available today, and advanced energy storage technologies that we are supporting for use in the future.

Duke Energy's goals and activities show our commitment to decarbonization. Further information can be found in our 2022 Climate Report and 2022 Impact Report.

II. Executive Summary

At Duke Energy, we approach the clean energy transition in a balanced way where reliability and customer affordability are foundational. We are making investments to reduce emissions and to lower fuel costs and price volatility, taking advantage of clean energy tax provisions in the Inflation Reduction Act (IRA) and working to receive funding for innovative technologies through the Infrastructure Investment and Jobs Act (IIJA). All of this factors into our current $145 billion, 10-year capital plan, of which 85% is targeted to fund our clean energy transition and grid modernization.[3]

Duke Energy is committed to achieving net-zero carbon emissions from electricity generation by 2050. Our interim goals are to achieve a reduction of at least 50% below 2005 levels by 2030 and an 80% reduction by 2040, on the way to net-zero carbon emissions by 2050.[4] We also have a goal to achieve net-zero Scope 1 methane emissions from our natural gas business by 2030.[5] We have ambitious plans for reducing our carbon emissions, including ceasing our coal burning by 2035, subject to state public utility commission regulatory approval and the availability of replacement generation.

This balanced approach is not new – through 2022, our carbon emissions from electricity generation are 44% below 2005 levels, achieved largely through retiring 56 coal-fired electric generating units representing nearly 7,500 megawatts (MW) of capacity. We have filed and are filing integrated resource and similar plans, as required in our jurisdictions, that are consistent with our goals and these comments. This stepwise, balanced approach has allowed us to reduce emissions and ensure reliability while maintaining affordable electricity rates for our customers; these affordable rates also attract economic development, capital investment and jobs to our states.

In Duke Energy's service territory, we are projecting customer usage to increase. Key drivers of this increased electricity demand are significant economic development and customer growth in many of the areas we serve, as well as increased electric vehicle growth. Recent federal laws like the IIJA, IRA, and the CHIPS and Science Act are also driving massive electricity demand growth for data centers and the onshoring of chip manufacturing. Any final rule from the EPA should ensure resource adequacy given the anticipated growth and the policy objectives of the IIJA, IRA, and CHIPS and Science Act.

We support EPA's interest in a clean energy future and believe that EPA's 111 proposal, with changes, could help further facilitate our clean energy transition. However, we believe changes are needed to the proposal to (1) align with the pace of technology development, demonstration and installation of supporting infrastructure, and (2) ensure that energy remains affordable and available at all times for our customers. Specifically, EPA should make the following changes to its proposed rule.

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[3] This capital plan was developed prior to EPA's proposed 111 rule and so does not include any projected costs for compliance with the proposal.

[4] Our goals are in line with the Paris Agreement, and our projected carbon intensity reduction for electricity generation is generally aligned with the 2°C scenario carbon intensity for electricity generation presented by the Transition Pathway Initiative.

[5] Duke Energy has also adopted ambitious goals for reducing Scope 2 and certain Scope 3 greenhouse gas emissions – to achieve a 50% reduction below 2021 levels by 2035 and to achieve net-zero emissions by 2050. Taken together, Duke Energy's Scope 1, 2 and 3 goals cover more than 95% of reported 2021 emissions.

- **Revisions Are Needed to the Proposed Standards for New Combustion Turbines**

EPA should increase the Phase 1 limit for new baseload natural gas combustion turbines (CTs) or combined-cycle (CC) units from 770 pounds (lb.) CO_2/megawatt-hour (MWh) to a limit that is achievable on a 12-month rolling average basis under a variety of operating conditions and duties. Otherwise, the flexibility of these units to accommodate additional renewables on the grid will be limited and costs will increase for our customers as operations and maintenance practices become substantially more frequent, complex and expensive. The limit should reflect the necessary variability in operation needed to accommodate significant, intermittent renewable additions to the grid, such as more rapid ramping, lower minimum loads, and more frequent startups and shutdowns. In addition, the standard should take natural performance degradation between major maintenance intervals into account.

Further, some applications where new baseload turbines are needed may not have the size or transmission capability to accommodate the largest, most efficient new combustion turbines. EPA should consider additional subcategorization and set standards for baseload CTs that vary depending upon the class (size) of the machine installed.[6]

- **Hydrogen and CCS Are Important Technologies but (Including Needed infrastructure) Are Not Yet Adequately Demonstrated and Will Not Likely Be Available for Wide-Scale Deployment Until the 2040s**

Duke Energy supports the use of hydrogen and CCS (and other advanced technologies such as new nuclear and long-duration storage) to reduce emissions from the power sector if (as projected) and when those technologies become cost-effective and available at the scales necessary, including supporting infrastructure, to support widespread application. We are working to spur hydrogen and CCS development by, for example, conducting a pilot-scale demonstration of producing hydrogen from solar and burning it in a gas turbine in Florida; proposing (with others) a Southeastern hydrogen hub; and working with DOE on a front-end engineering design study for CCS at one of our plants in Indiana. However, the timelines in EPA's proposal are not in alignment with industry and government workstreams to bring these resources to large-scale commercial availability.

Because neither the production, transportation, storage and use of "low-GHG" hydrogen in gas turbines, nor the use of CCS on a natural gas combined-cycle power plant have been demonstrated at the scale EPA proposes, nor does the extensive supporting infrastructure for these technologies exist, the hydrogen and CCS requirements for new and existing turbines would be extremely costly and

[6] See 42 U.S.C. 7411(b)(2): "[t]he Administrator may distinguish among classes, types, and sizes within categories of new sources for the purposes of establishing such standards."

difficult to implement in the timeframe EPA proposes and should be deferred until a later rulemaking when these technologies are mature.[7] In fact, at the scales EPA proposes for the 2030s, our projections show the technologies and systems required to operate the technologies at the proposed scale will be available no earlier than the 2040s.[8]

- **Extend the Capacity Factor Limitation Deadline for Existing Natural Gas Turbines**

EPA proposes the same hydrogen and CCS requirements for existing gas turbines as it proposes for new gas turbines. If, alternatively, CT owners choose to limit existing turbines' capacity factors to less than 50% (so that they are not subject to the proposed rule), it would require the construction of replacement generation in the 2030s, which would be very costly to our customers, with the possibility of little to no emission reduction benefits. Instead, EPA should extend the 2035 date for existing natural gas turbines to limit their capacity factors until non-emitting replacement generation is expected to be more readily available and until the technologies and systems required to operate hydrogen and CCS at the proposed scale are available.

- **Revise the "Near Term" Coal Retirement Date to Match the Availability of Replacement Generation**

Duke Energy's stated goal is to retire all its coal generation by 2035, subject to state public utility commission approvals, but it is essential that replacement generation that maintains or enhances reliability is available prior to retiring the coal. Consistent with our planning assumptions as outlined in our resource plans and our Climate Report, we suggest a slight modification to EPA's proposal for "near-term" coal units to extend the required retirement date from Dec. 31, 2034, to Dec. 31, 2035, to allow adequate time for dispatchable replacement generation to come online.

- **Coal Units Should Be Allowed to Transition to Full Natural Gas Capability During the 2030s**

Utilities, including Duke Energy, are planning to convert some existing coal units to 100% natural gas firing in the 2030s. This will reduce emissions and costs to customers by avoiding the need for additional replacement generation. EPA should encourage this by removing its requirement that a coal unit be defined as any electric generating unit that retains the capability to fire coal after Dec. 31, 2029.

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[7] EPA should also move the date for CCS deployment on existing coal facilities out past 2030. Installing CCS and having it operational by 2030, even at sites with favorable geology, is not feasible by 2030, given the fact that EPA is not likely to approve state plans until 2027 at the earliest. Plus, the few permits that have been issued by EPA for Class VI CO_2 sequestration wells have taken at least three years for issuance (after completion of an extensive permit application that requires many scientific and geological assessments).

[8] DOE's Pathways to Commercial Liftoff: Clean Hydrogen report (2023) shows a post-2040 cost breakeven for clean hydrogen for firm power generation (vs. a conventional alternative) (page 39).

EPA and the states should allow coal units to transition to full natural gas capability during the 2030s, with the existing natural gas emission limitations applying at the time of full natural gas conversion.[9] This will improve system reliability by keeping large units on the grid, reduce emissions (by switching from coal to natural gas) and help mitigate customer costs.

- **A Reliability Assurance Mechanism Is Needed**

Due to the challenges discussed above, EPA must include a reliability assurance mechanism in its final rule beyond the provision it currently proposes for grid emergencies (under which that power system operators can apply for an Administrative Compliance Order to allow deviation from the requirements of the rule when a grid emergency has been declared). However, it should be noted that such a reliability assurance mechanism is not an appropriate or sufficient replacement for a well-designed rule that imposes achievable standards based on technology that is adequately demonstrated.

Grid reliability must be planned years in advance to balance generation and electric demand every second of every day. EPA's proposed mechanism that essentially amounts to an enforcement waiver when a system emergency has been declared does not ensure grid reliability. The needed mechanism should provide short- and long-term waivers to ensure grid reliability well before grid emergencies. The instances where waivers are necessary could include delays in technology and infrastructure development and deployment, permitting and regulatory delays, supply chain impacts, transmission constraints and delays, and other factors. EPA's final rule should provide a reliability assurance mechanism that provides flexibility in case of the delays mentioned above well before a grid emergency is declared. It is our understanding that a group of ISOs/RTOs is providing comments with suggested modifications that would help mitigate the reliability impacts of EPA's proposal.

III. Modeling and Analysis of the Impacts of the 111 Rules

Duke Energy has reviewed EPA's modeling supporting the rule and has performed its own modeling analysis. This section includes our comments on EPA's modeling, our modeling assumptions and results, and some practical challenges with implementation of the proposal.

A. Observations About EPA's Modeling

In general, it appears that EPA's modeling in its Regulatory Impact Analysis (RIA) did not account for the practical execution challenges and risks associated with rapidly interconnecting large amounts of new clean generation within the proposed rule's timeline to meet customers' energy needs when large numbers of coal units retire and

[9] The owners/operators of such units should commit to increments of progress for the timeline to switch to natural gas during development of state plans.

when existing units' utilization is limited. Such resource additions require extensive and multiple adjudicated regulatory processes to gain approval to permit and construct them, significant community engagement, and extensive grid studies and upgrades, all of which depend on constrained supply chains and skilled labor resources.

These processes and studies are not represented in the model EPA used; it selects new generating resources constrained only by economics. The practical impact of this is that when the projected new (carbon-free and low-carbon) resources are not connected in the modeled time frame, the missing energy from those resources must necessarily be made up by impacted EGUs.

EPA's Regulatory Impact Analysis (RIA) makes the unlikely assumption that all the projected new resources are interconnected and available on EPA's proposed timetable and therefore the RIA underestimates the cost to replace the missing energy and capacity, and greatly underestimates the compliance costs of the proposed rule. The overstated resource additions also nullify the EPA analysis of the reliability implications of the proposed rule's restrictions on natural gas use and coal and gas unit capacity factors.

To address these concerns, the modeling assumptions should be based on consideration of logistics and historical data to constrain the pace of resource additions to a plausibly achievable level reflecting these types of practical limitations on resource additions. While it is appropriate to factor in a reasonable pace of improvements in these constraints over time, logistical constraints affecting the pace of grid transition must not be ignored.

Additionally, since the compliance costs are represented as the difference between the total production costs projected in the baseline and those projected in the proposal scenarios, it is also critical to have the baseline reflect an accurate expectation of the "business as usual" power system projected prior to the proposed rulemaking. Issues with the EPA modeling described below undermine the validity of EPA's baseline and subsequent policy analysis.

The EPA modeling is not sufficiently granular and robust to determine the impact of the proposal on resource adequacy. The capacity expansion model EPA relies upon uses a rough approximation of seasonal load patterns rather than modeling hour-to-hour changes in load throughout the years. It is therefore unable to fully evaluate the reliability and economics of the model's selected resources. The limitations of the EPA modeling approach bring into question the robustness of EPA's reliability analysis, particularly for winter weather and load patterns, which can be much more volatile than summer load patterns. Utilities and customers are quite sensitive to this winter reliability issue following several extreme winter weather events in recent years.

Best practices for resource planning incorporate probabilistic modeling to indicate the loss of load expectation for a given portfolio across an array of uncertain outcomes and weather patterns. Similarly, chronological hourly modeling provides additional confidence that a portfolio is resource-adequate when time-series constraints such as ramping, regulation and balancing requirements are enforced, and the absence of unserved energy can be validated.

Such assurance is particularly important in the context of a major transition in the types of resources serving customers over the next several decades, which may also include a need for higher reserve margins in the future to address increasing reliance on weather-dependent intermittent resources and energy-limited (storage) resources, as well as increasing wear and tear on load-following resources that may contribute to reduced levels of availability.[10]

Furthermore, the EPA modeling assumes a 15% reserve margin threshold for winter in the Carolinas region, which is substantially lower than the minimum winter reserve margin used by most utilities in the region, including Duke Energy Carolinas and Duke Energy Progress.[11] Winter will increasingly become the binding constraint for resource planning in many jurisdictions as more solar is added to the grid, energy-efficient heat pumps are added and electrification of heating becomes more prevalent.[12] It is worth reiterating that the proposed rule would constrain the dispatchable resources that are critical to maintaining reliability in such extreme winter weather events.

EPA's assumptions and modeling[13] project for the proposed rule that about 20 gigawatts (GW) of new renewables will be required in North Carolina and South Carolina by 2035, with about 10 GW of onshore wind (4 GW by 2030). EPA also assumes 5 GW of batteries and 7.5 GW of new natural gas combined cycles built by 2030, which would require significantly more natural gas pipeline infrastructure than currently exists. To meet this level of combined-cycle generation in the time frame shown, Duke Energy would need to pursue incremental interstate pipeline capacity to support this generation build within the next year. These assumptions result in EPA inferring all coal in the Carolinas is retired by 2030.

EPA's projections for these resource additions are significantly higher than even the most aggressive assumptions for the quantities of wind, solar, and storage that Duke Energy estimates could be deployed and interconnected within these time frames. For example, Duke Energy Carolinas' and Duke Energy Progress' recently filed 2023 solar procurement resource target is for 1,435 MW of solar, along with 260 MW of paired storage. Duke Energy will be releasing updated estimates for resource additions in the Carolinas in upcoming resource plan filings that reflect practical, logistical and projection execution considerations while also balancing the need to maintain the reliability and

[10] See, for example, ISO New England, *2021 Economic Study: Future Grid Reliability Study Phase 1*, July 29, 2022, pp. 2, 55.

[11] As noted in Duke Energy's recent stakeholder materials (Duke Energy Carolinas Resource Plans: Stakeholder Meeting 5, June 13, 2023, Meeting Slides, p. 14), we plan to file Carolinas resource plans utilizing a 22% reserve margin in August.

[12] American Council for an Energy Efficient Economy, Demand-Side Solutions to Winter Peaks and Constraints, April 15, 2021, p. 1.

[13] EPA, 05/09/2023, **Analysis of the Proposed Greenhouse Gas Standards and Guidelines**, Proposal.zip,Proposal RegionalSummary.xlsx.

affordability that our customers depend upon, along with the improved access to increasingly clean energy that they desire. As a result of these practical considerations, near-term additions reflected in the upcoming filings will be at lower levels than what EPA assumes, particularly for gas, wind and batteries added by 2030. Our modeling for the Carolinas does align with EPA modeling with respect to the need for flexible natural gas combined-cycle generation to enable renewable additions and coal retirements, as well as the need for a steady pace of solar additions to help reduce system carbon intensity and customer exposure to gas price volatility over time.

In the Midwest, Duke Energy faces additional challenges with deploying natural gas cofiring and CCS[14] and obtaining replacement generation.[15] Duke Energy's Midwest units are very near coal supplies but would face cost and complexity challenges in bringing required volumes of natural gas to several of the sites. CCS has not been demonstrated on a combined-cycle natural gas power generation unit and is highly dependent on the proper geology, which can vary greatly even within the same state. Using the state of Indiana as an example, one of the main target geological formations for CO_2 storage is the Mount Simon Sandstone. This reservoir's dimensions vary greatly across the state of Indiana; for example, the thickness ranges from 400 feet in eastern Indiana to 2,500 feet in northwest Indiana, and the depth of the formation varies from 2,500 feet to 13,000 feet. This level of variation illustrates the complexities of the technical information owners or operators must develop and submit to EPA or a state with an EPA-approved underground injection control program to obtain a permit to construct and then operate an underground injection well for sequestration purposes. These complexities are further discussed below in Section IX B.

B. Duke Energy Modeling – Assumptions and Results

Utilizing well-established planning principles and processes, overseen by state utility commissions and with participation from a variety of external stakeholders, Duke Energy regularly files integrated resource plans (IRPs) that detail our plans to provide growing amounts of increasingly clean, reliable and affordable energy that's available 24/7. These plans also transparently outline further CO_2 reductions through a prudent, orderly and cost-effective energy system transition. Multiple scenarios and sensitivities are analyzed to pressure test the modeling assumptions. Technology cost projections, resource availability, fuel cost curves and increasing customer demand align with industry standards and assumptions. These IRP analyses are consistent with resource plans to be filed in North Carolina and South Carolina later this month and are the basis for Duke Energy's carbon reduction targets. To assess the impacts of the proposed rule,

[14] Based on geology and tax credits under the Inflation Reduction Act, CCS appears to be a more economic option in the Midwest than in Duke Energy's other jurisdictions.

[15] In 2023, the Commonwealth of Kentucky passed Senate Bill 4, which prohibits the Public Service Commission from approving a request by a utility to retire a coal unit unless the utility demonstrates that the retirement will not have a negative impact on the reliability or the resilience of the electric grid or the affordability of customers' electric rates.

the requirements outlined in the proposed rule were applied to current IRP modeling for each of the Duke Energy utilities.[16] Observations are discussed below for coal and gas.

Coal – Duke Energy modeling reflects our enterprise's goal of retiring all our existing coal generation by 2035 and implementing transition plans based on increasingly clean replacement generation.[17] These coal retirement dates generally align with the EPA's proposed standards for "near term" coal units – that such units retire by Dec. 31, 2034. However, Duke Energy does plan to retire several units during 2035 and so would recommend that the "near term" date be moved to Dec. 31, 2035, so that adequate replacement generation could be assured of being in-service to ensure reliability for customers. As discussed further below under "Reliability Concerns" in Section XI, EPA should take these retirements into account in establishing a reliability assurance mechanism; that is, if a coal unit is required to retire by a certain date under the state plan developed for the section 111 rules and approved by EPA, there should be a reliability assurance mechanism so that it can remain in operation if replacement generation is not yet available.

Duke Energy's resource plans reduce reliance on coal generation over time, but some coal units that would be in the "near term" category are projected to remain above the proposed 20% capacity factor limitation after 2030. Such a broad restriction would increase reliance on market purchases, especially in peak demand periods. This would potentially threaten reliability, especially if neighboring power providers will also have additional energy needs for which they would look to the market to supply at coincident peak times.

Gas – To maintain reliability of the system while retiring over 15 GW of coal by 2035,[18] existing and new natural gas generation is necessary to ensure that Duke Energy can serve its customers' energy needs through all types of weather, including when sufficient renewable generation is not available, such as cold winter nights and early mornings. It is important to recognize that long-duration energy storage is not expected to be a large-scale, cost-effective solution for this challenge until the mid-2030s.[19]

Our current resource plans include over 30 GW of intermittent renewable resources on the Duke Energy system by 2035, which does reduce overall reliance on natural gas generation in the hours these intermittent resources are available. As, over time, the

[16] Note that Duke Energy does not file integrated resource plans for Duke Energy Ohio.

[17] Coal retirements are subject to regulatory approval and the availability of replacement generation. Contemplates retiring Edwardsport gasifiers by 2035 or adding carbon capture technology to reduce emissions.

[18] Id.

[19] DOE, The Pathway to Long Duration Energy Storage Commercial Liftoff, 2023, noting that "market liftoff" by 2030-2035 for long-duration energy storage requires improvements in technology, cost declines, regulatory support and supply chain development. Duke Energy's modeling of additional pumped storage and eight-hour lithium-ion batteries show that economics for longer-duration storage first become favorable in the mid-2030s, assuming an optimistic but achievable pace of renewable additions.

increase in renewable resources connected to the system occurs, and battery technology and new zero-emitting resources such as small modular reactors (SMRs) develop and are added to the system, the energy supplied from natural gas will decline, but it will remain a necessary resource for maintaining grid stability at night and during times of non-availability of weather-dependent renewables well into the 2040s.

EPA's modeling assumes that, instead of installing hydrogen cofiring or CCS, the capacity factor on existing natural gas generation would in many cases be limited to 50% beginning in 2035. For new natural gas units, the capacity factor would need to be limited to approximately 50% to be considered "intermediate" units. To meet these capacity factor limits and maintain reliability for our customers, additional resources would need to be added in our regions, increasing costs for customers.

As discussed above, Duke Energy is engaged with peer utilities, industrial customers and technology companies to advance the development and demonstration of initial, small-scale levels of hydrogen production and storage. We and others have applied for a DOE grant that would help establish a Southeastern hydrogen hub and we are also conducting a pilot-scale demonstration of producing hydrogen from solar in Florida and using it to fuel a combustion turbine for short periods of time.

Through our engagement in hydrogen development and in alignment with current resource plan assumptions, our general view is that the buildout of hydrogen infrastructure will be a gradual process, beginning with much smaller percentages of hydrogen blending in our natural gas units starting in the mid-2030s and increasing gradually over time as the clean energy buildout provides surplus zero- or low-marginal-cost clean energy that can be used to produce hydrogen at times the renewables or other clean energy sources (nuclear) are not needed to power the grid.[20]

As discussed below, it would require an unrealistic acceleration of the infrastructure necessary to produce the levels of "low-GHG" hydrogen required to operate intermediate and baseload resources at the blend rates prescribed in the proposed rule starting in 2032. Even assuming this is accomplished, our analysis shows *no* acceleration of carbon emissions reduction due to industry-standard economic dispatch principles. In other words, because the hydrogen would be so expensive to produce, transport and burn in this time frame, those units equipped to burn it would not be dispatched to produce electricity for customers. Again, delaying hydrogen requirements until the technology and market have developed, costs for electrolysis and storage have

[20] Ironically, due to EPA's proposed requirement for hydrogen to be produced at 0.45 kg CO_2-e/kg H_2, the proposal would require the construction of dedicated renewables to produce electricity, convert that electricity to hydrogen fuel at about 60%-70% efficiency (see Institute of Power Engineering, FAQ_final_EN.pdf (ien.com.pl)) and convert the hydrogen back to electricity at about 40% efficiency (see Nature Portfolio, "Hydrogen gas turbine offers promise of clean electricity," 2022). This shows the significant efficiency penalty associated with the use of stored hydrogen when renewables are not available, when and if low-GHG hydrogen production and transportation systems develop to the point of being adequately demonstrated and cost-effective.

decreased and sufficient surplus clean energy becomes available for hydrogen production, would best support reliability and customer affordability needs.

C. Practical Challenges with Implementation of the Proposed Rule

In addition to the challenges discussed above that are shown by the company's modeling, based on extensive experience with building new power plants (natural gas, nuclear and renewables) and with attempting to permit and construct new pipelines, Duke Energy foresees significant challenges with attempting to implement EPA's proposed rule in the time contemplated.

Hydrogen – While Duke Energy is committed to the development and use of hydrogen, the steps it would to take to comply with the hydrogen cofiring requirements would be extremely difficult because the "low-GHG" hydrogen that EPA would require to meet the rule is not currently being produced in the United States at any level of significance.[21] This means that a new hydrogen production infrastructure (with additional new clean energy resources to power new electrolyzers) must be developed, as must hydrogen pipelines and storage facilities that do not currently exist in any of Duke Energy's service territories.

From the standpoint of hydrogen production, the DOE's regional hydrogen hubs funded from the Infrastructure Investment and Jobs Act will be a start toward the beginnings of a low-GHG hydrogen supply in the regions awarded, but Congress did not appear to envision the scale needed to provide 30% hydrogen by volume by 2032 and 96% hydrogen by volume just six years later for tens of thousands of megawatts of natural gas generating capacity.

The scale of assets needed to produce, transport and store enough low-GHG hydrogen would be enormous. As an example, for just Duke Energy's existing and currently planned combined-cycle fleet in the Carolinas that would be subject to the proposed rule, to meet the 2032 30% hydrogen by volume requirement would require:

- Construction of an additional 4 GW of solar (above and beyond the aggressive amounts of solar already shown in our integrated resource plans).[22] It would not be possible to locate this amount of new solar on-site at our existing CCs, so the solar would either need to be located at other sites and transmitted to the electrolyzers at the CCs through the existing grid (using renewable energy credits) or through dedicated transmission lines. Alternatively, the electrolyzers

[21] EPA states that hydrogen used for cofiring under its rule must meet the 0.45 kg CO_2/kg hydrogen standard of Section 45V of the Internal Revenue Code. Such low-emitting hydrogen can be made by electrolyzers powered by renewable energy or nuclear energy. According to DOE's Market Liftoff report for hydrogen, less than 1% of current U.S. hydrogen production is sourced from electrolysis powered by renewables and nuclear. (See Pathways to Commercial Liftoff - Clean Hydrogen (energy.gov), p. 10.)

[22] This solar would also need to be interconnected to the grid and, unless current interconnection queue problems are solved, this will be another huge challenge. See, for example, https://www.utilitydive.com/news/energy-transition-interconnection-reform-ferc-qcells/628822/.

could be sited with the solar, and new hydrogen pipeline infrastructure would be required to transport the hydrogen to the CCs.
- Construction of approximately 4 GW of electrolyzers (which is more than the world's current on-line supply).[23]

Assuming the 30% volume requirement could be met on an annual average basis, limited on-site liquid storage would be required, but even with that, this infrastructure will likely take at least a decade to develop from the time commitments to hydrogen are made in state plans (for existing units) or in permit conditions (for new unit), both of which will not occur until at least the late 2020s. Therefore, even if the supply chain for these materials on such a scale were available and executable, this time frame estimate is likely considered a best-case scenario.

In this example, the buildout for 96% compliance would be even more colossal as Duke Energy Carolinas' and Duke Energy Progress' CC fleet that would be subject to the section 111 rule would essentially need enough hydrogen to supply their "full requirements" 24/7/365 to ensure grid reliability. We project that meeting the 2038 96% hydrogen by volume compliance would require:

- An additional 24 GW of solar, for a total of 28 GW of solar for Duke Energy Carolinas' CC compliance. This amount of solar would cover a land area more than five times the size of the District of Columbia.[24]
- An additional 24 GW of electrolyzers, for a total of 28 GW of electrolyzers for compliance. It is unknown if future electrolyzer manufacturing production capacities could and would increase to support Duke Energy's and other entities' needs. Note that in footnote 23 we cite a 2023 IEA report that states that (global) "electrolyzer capacity could reach almost 3 GW by the end of 2023."
- Unlike with 2032 compliance, a liquid hydrogen storage pathway would not be the ideal path for compliance given the need for seasonal hydrogen storage at a 96% blending requirement. Seasonal storage would be required to move excess spring hydrogen production from renewables to demand for winter peak consumption, similar to how the current natural gas storage system works. It would be extremely expensive and challenging to use liquid hydrogen given the sheer number of above-ground steel tanks that would need to be constructed. Another alternative would be underground rock cavern storage, but there is no such commercially operating facility in the world. Thus, that leaves salt dome storage as the only proven storage medium that could facilitate Duke Energy's seasonal hydrogen storage need for 96% compliance. Given this would require access to the Gulf Coast region, extensive large bi-directional pipeline

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[23] International Energy Agency (IEA), Tracking Clean Energy Progress 2023, stating "electrolyzer capacity could reach almost 3 GW by the end of 2023, a more than four-fold increase in total capacity compared to 2022."

[24] Solar requires approximately 8 acres per MW (per DOE's National Renewable Energy Laboratory); using 28 GW for 96% compliance, this is equal to 224,000 acres. The land area of the District of Columbia is ~44,000 acres (per Greater Greater Washington).

infrastructure would be required. For clarity, both rock cavern and salt dome storage would also require a new intrastate hydrogen pipeline system.

This hydrogen compliance program would involve multiple high-execution risks with an unprecedented scale of buildout. For example, Duke Energy alone would need production facilities for low-carbon hydrogen that are multiples of current global capacity. Current global installed capacity is less than 3 GW;[25] Duke Energy would need to install 3-4 GW annually for eight years for just the 30% hydrogen scenario. As to storage, there are only three hydrogen salt domes in the U.S. today; Duke Energy alone would need an estimated 60-70 similarly sized for seasonal hydrogen storage. And for the pipelines to and from hydrogen production and storage areas, there are significant unknowns around federal and state permitting processes, federal regulatory jurisdiction and litigation risks.

Further, from an executability standpoint, it is almost impossible to envision a new network of hydrogen pipelines being built by private industry without significant nationwide permitting reform and eminent domain enhancements. In addition, it is not clear which federal agency has jurisdiction over hydrogen pipelines. The concerns surrounding pipeline permitting and construction are described in Section X.

Additionally, legal uncertainty would likely provide additional headwinds for private development of hydrogen pipelines. For example, litigation and decisions by the U.S. Court of Appeals for the 4th Circuit have held up the Mountain Valley Pipeline natural gas project (which has been nearly a decade in the making) to the point that Congress enacted a law to attempt to move this project forward.[26] Critically, several other large natural gas pipeline projects have been canceled in recent years due to state, property owner and environmental opposition and litigation, including the Atlantic Coast, Constitution and PennEast pipelines. It is likely that the network of hydrogen pipelines necessary for compliance with this rule would face similar issues.

As noted above, even assuming this hydrogen infrastructure is built, our analysis shows *no* acceleration of carbon emissions reductions; during this time frame, the units with hydrogen capability would not be utilized while cofiring hydrogen due to the significant cost to customers.

CCS – Financially, the 45Q tax credits within the recently enacted IRA constitute a significant incentive for CCS. However, capture technology has not yet been demonstrated and is not yet commercially available for natural gas turbines in the power generation industry. And the proper geology for sequestration does not exist at all

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[25] International Energy Agency (IEA), Tracking Clean Energy Progress 2023, stating "electrolyzer capacity could reach almost 3 GW by the end of 2023, a more than four-fold increase in total capacity compared to 2022."

[26] The 4th Circuit Court of Appeals again stayed construction of MVP following the passage of the Fiscal Responsibility Act. Upon motion by the owners, the U.S. Supreme Court on July 27 vacated the 4th Circuit stay. On that same day, the 4th Circuit heard scheduled oral arguments on the pending motions to dismiss.

power plant sites.[27] If the right geology does not exist (which we believe would be the case for our Carolinas and Florida locations), then the CO_2 would need to be captured and piped to a location with the proper geology for sequestration or to a site where the CO_2 could be used (for example, for enhanced oil recovery; this type of usage is also known as carbon capture, utilization and sequestration (CCUS)).

However, logistically, there are questions about whether the volumes of CO_2 captured by numerous power plants could be piped directly to utilization or sequestration sites. If large numbers of power plants install CCS, it would require a separate network of CO_2 pipelines in addition to the potential new hydrogen pipelines discussed above. Regardless of which is transported, it is reasonable to expect that both would face opposition and legal challenges to local, state and federal permits given the current permitting framework. In addition, as discussed below in Section IX B, CO_2 sequestration in underground repositories requires not only Class VI injection well permits from EPA or the state (if the state in question has primacy for well permitting),[28] but also acquisition of pore space, both of which add time and uncertainty to any CCS project.

In sum, not only would EPA's proposal be extremely expensive for Duke Energy's customers, but it is also highly likely that executing the infrastructure needed to comply with the rule would be impossible to achieve on Duke Energy's system at the scale needed in the time EPA proposes. Extrapolating Duke Energy's situation to the larger industry, it is virtually certain that this rule cannot be implemented on the schedule that EPA has laid out.

D. This Rule's Enormous Costs Would Divert Resources from Needed Expenditures on New Technologies and Grid Improvements to Make the Clean Energy Transition

Duke Energy is leading one of the country's largest clean energy transitions, one designed to achieve net-zero carbon emissions from electricity generation by 2050. The electric power industry as a whole is on the path to decarbonization, as can be seen by the commitments by many other companies. Given this proposed rule's enormous cost, difficulty of implementation and relatively small incremental CO_2 emission reductions (EPA's Regulatory Impact Analysis shows a maximum reduction due to the proposal of 9% in 2030 across the electric power sector, compared to business as usual),[29] it will divert financial and human resources away from the development and deployment of

[27] Post-combustion capture technology for coal-fired power plants has been demonstrated on a slip stream at the W.A. Parish coal plant in Texas (the Petro Nova demonstration) and is being operated at the Boundary Dam site in Canada.

[28] Under the Safe Drinking Water Act.

[29] EPA, Regulatory Impact Analysis for the Proposed 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 (May 2023), pp. 3-15.

the technologies that are needed to transition the power sector to clean energy and away from the grid improvements needed to effectuate the clean energy transition. For example, compliance with this rule (if finalized), by focusing on only certain new technologies (hydrogen and CCS), will divert resources away from development of other promising technologies like new nuclear and long-duration storage that need to be developed to provide the dependable grid we need in the future.

IV. Duke Energy's View of What Requirements and Timing Could Be in a Workable Final Rule

Duke Energy has ambitious goals to reduce carbon emissions from our electricity generation. These begin with a goal to reduce emissions by at least 50% by 2030, followed by an 80% reduction by 2040 and net-zero emissions by 2050. We also plan to retire all coal generation by 2035, subject to state public utility commission regulatory approval and the availability of replacement generation.[30] Our customers' needs for electricity are increasing; at the same time, they are concerned about increasing energy costs and reliability. Duke Energy believes in an orderly transition ensuring that system reliability, 24/7 resource availability and reasonable customer costs are kept in balance throughout the transition process.

- **Existing natural gas units –** EPA has proposed requirements for larger baseload existing combustion turbines that are essentially the same as those it proposed for new turbines – to cofire hydrogen by 2032 and 2038, or to install CCS by 2035. As discussed elsewhere in these comments, these technologies are not "adequately demonstrated" as required by the Clean Air Act.[31] Challenging problems exist with production, transportation and cost of "low-GHG" hydrogen and with capture, transportation and sequestration for CCS. These problems will take years to solve and would be even more challenging for existing turbines than for new turbines. For example, significant costly retrofits would be needed for existing turbines to accommodate hydrogen cofiring or CCS, and transportation challenges for hydrogen production and for carbon sequestration are exacerbated for existing turbines because the locations of those units are already determined, and utilities did not take hydrogen or CCS into consideration when the units were sited and constructed.

  If owners of existing CT and CCs choose instead to keep their units' capacity factor below 50% to avoid the hydrogen or CCS requirements, our modeling shows that replacement capacity will be needed, increasing costs for customers, and perhaps not resulting in a significant reduction in overall carbon emissions. Duke Energy's projections indicate that existing CCs' capacity factors will naturally decline in the 2040s due to new, non-emitting capacity (such as new nuclear) coming online. Therefore, any such capacity factor limitation should be delayed until the 2040s.

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[30] Contemplates retiring the Edwardsport IGCC plant gasifiers by 2035 or adding carbon capture technology to reduce emissions.

[31] 42 U.S.C. 7411(a)(1).

- **New natural gas units –** EPA should limit the final rule to the proposed Phase I standards (revised, as discussed below) only and evaluate its standards during the next new source performance standards (NSPS) review cycle as technologies are developed and demonstrated and supporting infrastructure is installed.[32,33] At the time of the next revision, the standards for new gas units could be revised if hydrogen and CCS are adequately demonstrated and infrastructure supporting those technologies is available.

  In addition, EPA should revise the Phase 1 limit for new baseload CTs or CCs from 770 lb. CO_2/MWh to a limit that is achievable on an annual average basis and that reflects the necessary variability in operation (such as performance degradation, startup and shutdown and cycling to match generation with electricity demand). The Gas Turbine Association is providing detailed comments on this issue. Importantly, some applications where baseload turbines are needed may not have the size or transmission capability to accommodate the largest, most efficient new combustion turbines. EPA should consider additional subcategorization and set standards for baseload CTs that vary depending upon the class (size) of the machine installed.[34]

- **Coal –** EPA's proposed approach to existing coal units generally aligns with our goal to eliminate the burning of coal by 2035, subject to state public utility commission regulatory approval and the availability of replacement generation. However, we have found in our modeling that to maintain grid reliability, there should be two changes made to the requirements for "near term" coal units. First, the retirement date should be extended to Dec. 31, 2035. As discussed above, this aligns with our filed resource plans and will allow time for replacement generation to be built. Second, our modeling shows that our units that would be in the "near term" category are needed for grid reliability from 2030 to 2035 and may well be called on to operate above a 20% capacity factor limitation. Therefore, the 20% capacity factor limitation for near-term coal units should be increased for the period 2030 to 2035 to ensure grid reliability.

  EPA should make it clear that coal units can switch to 100% natural gas during the 2030s and continue operating. Instead of needing to restrict heat input from coal to less than 10% in 2027-2029 and fully shift to natural gas by the end of 2029, coal units should be able to switch to 100% natural gas anytime during the 2030s and continue operating as long as they retire the coal capability by Dec. 31, 2039, and

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[32] The Clean Air Act provides that EPA must review and, if deemed appropriate, revise new source performance standards at least every eight years. Clean Air Act, 42 U.S.C.7411(b).

[33] As discussed in Section XII below, EPA's justification for proposing this multi-phase BSER standard as a way to avoiding the Clean Air Act's requirement that BSER be "adequately demonstrated" is inadequate.

[34] "The Administrator may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards." 42 U.S.C. 7411(b)(2).

switch to the appropriate natural gas subcategory. EPA should encourage this as it will reduce emissions and reduce reliability risks.[35]

- **Reliability assurance mechanisms –** EPA should establish reliability assurance mechanisms for both the section 111(b) and section 111(d) standards in the event planned generation intended to replace energy provided by a unit scheduled to retire is not available, or technology intended to be used to comply with the section 111 standards (e.g., CCS or hydrogen) is not available, due to factors beyond the affected source owner's control, including but not limited to unavailability of technology (e.g., new nuclear technology, battery storage, hydrogen, CCS, etc.); insufficient deployment of critical supporting infrastructure; interconnection queues; supply chain constraints; permitting delays or denials despite timely submittal of administratively complete permit applications; and litigation. Application of reliability assurance mechanisms to address these real-world challenges would allow units to remain in operation until replacement generation or complying technology becomes available to ensure that energy remains affordable, reliable and available at all times under the final rule.[36] This provision is critically important because dispatchable generation is needed for not only grid reliability but also grid stability.

- **Harmonization with other requirements –** EPA should harmonize the compliance dates in any final section 111 rule with its other regulatory standards for electric generating units, including, for example, the effluent limitations guidelines.

  EPA must also provide for synchronization of the proposed rule with other regulatory compliance requirements since projects take time to get through the regulatory pipeline for both regional transmission organizations (RTOs) and regulated jurisdictions. These requirements include RTO planning years, integrated resource planning cycles and certificate of public convenience and necessity approval timelines.

V. Comments Related to EPA's Definitions of Subcategories

A. Subcategories for New Natural Gas Units by Capacity Factor

In general, EPA has chosen to subcategorize new gas turbines into baseload, intermediate and low load categories based on capacity factors. However, the capacity factor of a unit can change greatly year over year based on electrical demand, weather, fuel prices and outages at that unit or at peer units.

For example, "intermediate load" is a new subcategory that industry manufacturers have not previously defined. As mentioned above, capacity factor is a dynamic number

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[35] Such units should commit to increments of progress for the timeline to switch to natural gas during development of state plans.

[36] See Section XII A regarding EPA's lack of authority to impose a BSER requirement based on technologies that are not adequately demonstrated.

affected by multiple factors. This is especially true for the proposed “intermediate load” units, where a peaking unit (<20% capacity factor) could easily fall into an intermediate load status just based on abnormal weather patterns. For example, Duke Energy’s Wayne County units 12-14 located at the H.F. Lee Plant in North Carolina started an average of 137 times in 2022 based on weather patterns and nearby unit outages, but in 2023 these same units are on track to start an average of just 12 times for the year. Similar trends can also be seen at other simple-cycle units like Asheville Unit 3&4 CTs located at the Asheville Plant in North Carolina, which saw their starts average drop from 131 in 2022 to 14 in 2023. Ordinary changes in demand and market conditions will routinely reverse these trends.

Any definition related to capacity factor should be weighted over a multiyear period to normalize out planned major maintenance outages, weather events or the myriad of other factors that cause variability in capacity factor over time. This variability is expected to increase over time for gas turbines, as well, as more renewables are installed on the system and gas turbines are called on to back up the intermittency of renewable generation.

Given these changes over time, in addition to multiyear averaging, EPA should provide greater flexibility for units to change subcategories as more renewable energy is added and/or operating conditions evolve.

B. Subcategorization of New Natural Gas Units by Size

EPA has proposed to only classify new natural gas combined-cycle and simple-cycle combustion turbines into baseload, intermediate or low utilization subcategories based on capacity factor. In doing so, it has proposed a performance standard for baseload units at 770 lb. CO_2/MWh for all machines greater than 2,000 million British thermal units per hour (mmBTU/hr.) based on the performance of only the very largest combustion turbine models currently available from vendors.[37] It also proposed a higher emission rate standard for smaller baseload units less than 2,000 mmBTU/hr. of heat input, and then no subcategorization by size for the intermediate and low utilization combustion turbines (the subcategorization for intermediate and low-utilization turbines is based on capacity factor).

In proposing a largely “one size fits all” approach for intermediate and low-utilization natural gas turbines, EPA has not fully recognized that medium- and smaller-sized combustion turbines are not capable of the same level of performance as larger machines. Similarly, EPA has not acknowledged that when designing a new facility, it is very critical to match the size of a turbine to the needs of the individual project. Put simply, it is not appropriate or feasible to force fit a larger combustion turbine into a smaller project need just because the larger machine is more efficient and has a lower emission rate. In the final rule, EPA should create additional subcategories by size with

[37] Duke Energy’s concerns with the stringency of this standard are further described in Section VIII A.

less restrictive standards to reflect the lower efficiencies of medium- and smaller-size turbines.

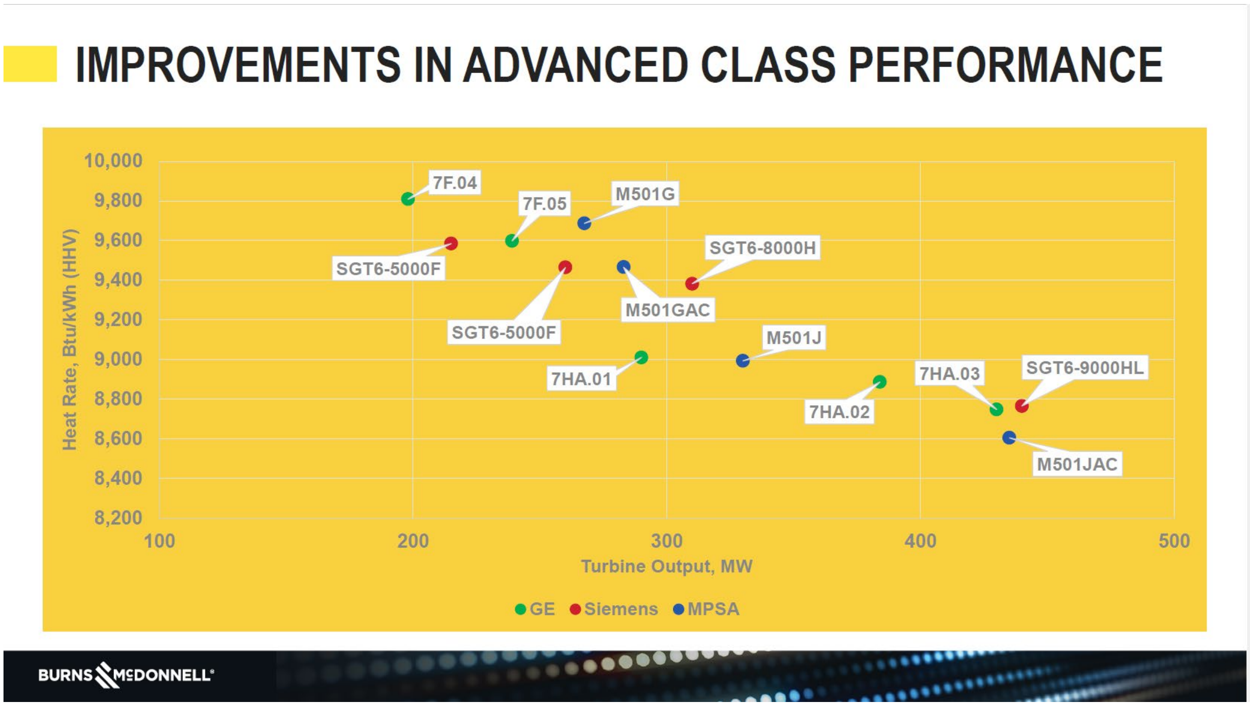
Under CAA section 111, EPA possesses authority to distinguish among classes, types and sizes of sources within existing categories for purposes of regulating GHG emissions.[38] EPA also has significant discretion to determine the appropriate level for the standards. Section 111(a)(1) provides that NSPS are to "reflect the degree of emission limitation that are **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." (emphasis added)

As stated in the above quote, costs are also considered in evaluating the appropriate standard of performance for each category or subcategory. EPA generally compares control options and estimated costs and emission impacts of multiple, specific emission standard options under consideration. As part of this analysis, EPA considers numerous factors relating to the potential cost of the regulation, including industry and market structure; control options available to reduce emissions of the regulated pollutant(s); and costs of these controls.

The following chart[39] focuses on the efficiency of new combustion turbine units currently on the market by displaying the amount of heat energy (Btus) needed to make one unit of electricity (kWh) when operated in a simple-cycle configuration.

[38] See above at footnotes 7 and 34 and 42 U.S.C. 7411(b)(2).

[39] Chart prepared for Duke Energy by Burns & McDonnell using data from Gas Turbine World 2022 Performance Specs, 38th Edition.



This chart shows the "heat rate" of various classes (sizes) of turbines. Heat rate is a measure of efficiency – the more efficient the unit, the lower the heat rate (the number of Btu's it takes to make a kilowatt-hour of electricity). It shows that smaller turbines have higher heat rates, are therefore less efficient, and emit more CO_2 per MWh. The graph clearly demonstrates that the heat rate (as a measure of efficiency) of new combustion turbines in the range of about 200 MW is approximately 10% higher (less efficient) than those greater than 400 MW. Medium-sized combustion turbines of about 300 MW can still be about 5% less efficient than the largest turbines. The chart also applies to combined-cycle units because their overall efficiency is directly related to that of the gas turbine itself. These are significant differences that EPA does not capture by only having one size subcategory. EPA should fully recognize the different capabilities of small- and medium-sized combustion turbines with additional subcategories by size and standards appropriate to the units in those subcategories.

C. Existing Gas Combined Cycle Subcategory

EPA's proposed emission guidelines for existing combined-cycle units apply to units with a capacity greater than 300 MW[40] and a capacity factor of greater than 50%. The agency states that it is soliciting comments on these size and capacity factor cutoffs and whether they should be reduced. While Duke Energy believes that EPA's proposed Best System of Emission Reduction (BSER) for the existing gas combined-cycle subcategory is based on technologies that are not adequately demonstrated (hydrogen and CCS), Duke Energy does support the cutoffs – these cutoffs are appropriate for larger,

[40] Including its pro-rata share of steam turbine capacity.

baseload combined-cycle units – and does not believe they should be reduced, even in a later rulemaking.

D. Existing Coal-Fired EGU Subcategories and Natural Gas-Fired Steam Generating Units

The proposed rule defines a “coal-fired steam generating unit” as a unit that burns coal for more than 10% of the average annual heat input during the three calendar years prior to Jan. 1, 2030, or for more than 15% of the annual heat input during any one of those calendar years, or that retains the capability to fire coal after Dec. 31, 2029. It also defines “natural gas-fired steam generating unit” as one that “no longer retains the capability to fire coal after December 31, 2029.”

As explained elsewhere in these comments, Duke Energy has units that currently cofire coal and natural gas that we plan to convert to 100% gas-firing during the 2030s. As proposed, those units would remain under the “medium term” coal category and be required to retire by the end of 2039. However, these units, once they begin firing 100% gas, will have significantly lower emissions than similar coal units. EPA should encourage, not discourage, such conversions and allow coal units converting to 100% natural gas to switch to the Existing Steam EGU (gas-fired) subcategory during the 2030s. We would like to discuss increments of progress to which such units would be subject to ensure that they do follow through on stated plans.

E. Edwardsport-Specific Issues

Duke Energy currently operates the Edwardsport integrated gasification combined-cycle (IGCC) unit in Edwardsport, Ind. It includes a coal gasifier, a gas turbine and two heat recovery steam generators. This 618-megawatt IGCC facility is one of the cleanest and most efficient coal-fired power plants in the world and is the only IGCC currently operating in the United States. Under the proposed rule, Edwardsport would be considered part of the coal subcategory.[41]

Currently, Duke Energy plans to retire the gasifier at Edwardsport in 2035 and use the combined cycle going forward as a gas-fired unit. EPA states that it considers existing IGCC units capable of precombustion CO_2 capture by removing carbon monoxide (CO) from the syngas prior to combustion. However, precombustion CO_2 capture (by removing the CO) was not designed into Edwardsport, and removing CO, which is a component of the syngas burned in the turbine for its energy value, would be fundamentally redefining/configuring the source and reducing its overall efficiency.

Edwardsport is already capable of running on 100% natural gas and is capable of exceeding the 40% natural gas cofiring requirement. Therefore, if Duke Energy retires the Edwardsport gasifiers in 2035, it would be more appropriate to consider the unit an existing gas turbine subject to those final requirements. However, as discussed

[41] 88 Fed. Reg. 33,240, 33,342.

elsewhere, Duke Energy believes the final rule should not include CCS or hydrogen cofiring until those technologies are adequately demonstrated.

Another compliance option for Edwardsport would be to continue coal operations but add CCS. Under EPA's proposal, this would be required by 2030. However, adding CCS by 2030 is likely not achievable given the complexities of permitting and construction of such an addition, even if the geology on-site proves to be feasible for sequestration.[42] As such, if EPA leaves CCS as a compliance option, Duke Energy recommends a 2032 or later date to require CCS on coal plants. Alternatively, EPA could establish a separate subcategory for IGCC units that requires 100% conversion to natural gas by a certain date, preferably 2035. At that point, BSER for the unit should be similar to those intermediate load gas turbine units.

F. Other Comments Requested by EPA on Subcategories

In the proposed rule, EPA solicits comments as to whether an annual mass emission limitation should be applied to the imminent term subcategory for existing coal to reflect reduced utilization and higher emission rates over time. Duke Energy believes that states should be allowed to set an annual mass emissions limitation for both the imminent **and** near-term subcategories. This mass emission limitation should replace the current proposed requirement for these units to not increase their annual emission rates *and* the proposed requirement for near-term units to not exceed a 20% annual capacity factor. This would allow for changes in efficiency/emissions rates as these units are increasingly used in a cycling manner to back up renewables and to provide energy needed to supplement natural gas units in case the 50% capacity factor limitation remains in place.

Importantly, Duke Energy agrees, as EPA states at 88 Fed. Reg. 33,345, column 3, that subcategorization does not preclude states from considering remaining useful life and other factors (RULOF) in applying a standard of performance to an individual source. In fact, EPA states, "a particular source may still present source-specific considerations – whether related to its remaining useful life or other factors – that the state may consider relevant for the application of that particular source's standard of performance …" For example, as discussed below in Section XIV A, a unit's cost to install BSER technology could be determined by the state to be unreasonable and, based on that fact and the unit's remaining useful life, not be required.

VI. Comments on EPA's Proposed Phase 1 Emissions Standards for New Natural Gas Units

EPA's proposed Phase 1 annual average emission rate limit of 770 lb. CO_2/MWh is based on a very limited number of unit types operating at full load or near full load. Even if these large, new machines could operate at full load or near full load and achieve 770

[42] As noted above, this spring, DOE announced that it had selected Duke Energy Indiana for award negotiations for a front-end engineering design (FEED) study for post-combustion capture at Edwardsport.

lb. CO_2/MWh on an annual average basis, these large machines are not suited for all applications (for example, they require large sites with sufficient fuel supply, high-voltage transmission interconnections, etc.).

However, it is rare, even in the “baseload” category as EPA has proposed to define it, for combined-cycle units to operate at full load or near full load for significant portions of the year. Under EPA’s proposal, units would need to comply while including partial load, startup, and shutdown conditions and during years when performance is declining due to natural degradation prior to maintenance outages (see discussion below). However, during these necessary operating conditions, CO_2 emission rates tend to be higher due to gas turbines not operating at peak efficiency. These circumstances are not reflected in EPA’s modeling analysis. Running at part load is critical for grid support, especially as renewables penetrate the grid, and quick response from rotating assets (combustion turbines and steam turbine generators) is required to stabilize the grid from weather cycling (clouds, etc.).

However, as noted above, part-load operation (including startup and shutdown) and operation as a unit approaches maintenance outages reduce turbine efficiency and increase CO_2 emissions rates. This should be factored into the appropriate standards.

Mandating units to run at peak efficiency for most of the year to meet these new emissions limitations is not realistic and will threaten grid stability and reliability or require curtailment of renewable resources, which is counter to the objective of the proposed rule. While operating at full load, all generating units – and especially natural gas-fired units – constantly need to respond to changing grid conditions such as changing and balancing load, maintaining system voltage level, and other needs. The need for this balancing duty from natural gas turbines is becoming more acute as higher levels of renewable energy are connected to the grid.

As mentioned above, it should also be noted that it is normal and expected that after new CT/CC units go into service, their performance experiences some degradation over time due to normal internal component wear and fouling. (This is similar to an automobile’s gas mileage degrading over time due to engine wear.) This degradation will continue until performance is restored at the next Hot Gas Path (HGP) or Major Inspection (MI) outage. Therefore, even for the most advanced class turbines, the 770 limit will be increasingly challenging to meet the longer the time passes since the previous unit outage.

This degradation, combined with duct-firing, as well as part-load and cycling operation due to more renewables being installed on the system, makes EPA’s 770 lb. CO_2/MWh very difficult to achieve. EPA should therefore consider, as the Gas Turbine Association and its member companies are pointing out, increasing the 770 lb. CO_2/MWh emission limit for new baseload gas turbines to reflect real-world operating conditions.

Additionally, EPA’s 770 lb./MWh limit reflects the very latest, large, advanced-class natural gas turbines. Further analysis must be done for other sizes of combustion turbines, and EPA should create additional subcategories based on unit size with standards that reflect the capabilities of those machines.

VII. Comments on Proposed Emissions Standards for Existing Units

A. Existing Steam EGU (Coal-Fired) Standards Under 111(d)

EPA proposes standards for existing steam EGU (coal-fired) using four categories: "imminent term" (which must not increase their annual average emissions rate above a baseline and must retire by Dec. 31, 2031); "near-term" (which must not increase their annual average emission rate above a baseline value, must limit capacity factor to 20% starting in 2030 and retire by Dec. 31, 2034); "medium-term" (which must meet an emissions rate based on 40% gas cofiring starting in 2030 and retire by Dec. 31, 2039); and "long-term" unit (which must install 90% CCS by Jan. 1, 2030).

As noted above, Duke Energy's goal is to eliminate coal firing by 2035, subject to state public utility commission regulatory approval and the availability of replacement generation. Given this and given the fact that Duke Energy has units that do not have access to natural gas cofiring and for which our modeling projects a need for utilization through 2035, we request that EPA extend the "near-term" retirement date from Dec. 31, 2034, to Dec. 31, 2035. That will allow time for replacement generation, including interstate natural gas pipelines as needed, to be installed.

In addition, EPA should increase the 20% annual capacity factor limit for "near-term" coal units and/or allow states to set annual mass emissions limits for "imminent-term" and "near-term" coal units during their remaining useful lives. EPA should also allow averaging among coal units. This would help ensure system reliability as many other power plant operators in the markets in which Duke Energy operates may also determine that coal units are in the near-term category, limiting their capacity factors to 20% and seeking replacement energy in the market.

EPA's requirements to identify subcategories for coal units at proposed 40 CFR 60.5740b(a)(1)(A)-(D) state that each category of coal unit must commit to "cease operations" by the dates noted above. As discussed previously, Duke Energy (and perhaps other utilities) plans to convert certain coal units to 100% natural gas and seek re-categorization into the Existing Steam EGU (gas-fired) subcategory. Therefore, the phrase "cease operations" in proposed 40 CFR 60.5740(a)(1)(A)-(D) should be changed to "cease coal operations."

As for the long-term coal unit proposed requirement, Duke Energy recommends the CCS requirement be extended to 2035 or later to recognize the infeasibility of installing CCS by 2030 and to otherwise sync up the cease coal operations date for near-term units with the CCS date for long-term units.

Also, in proposed 40 CFR 60.5740b(a)(5), EPA proposes a number of requirements for a "Milestone Report" that states must require in their state plans for imminent-term, near-term and medium-term coal units. Among these requirements is "[a]n analysis of how the process steps, milestones, and associated timelines included in the Milestone Report compare to the timelines of similar units within the state that have permanently ceased operations within the 10 years prior to the date of promulgation of these emission guidelines." This information is not relevant as each coal retirement has its own rationale and individual circumstances, nor is such information on the timelines of other units readily available retroactively. This requirement would therefore be burdensome and unproductive and should be removed.

B. Existing Natural Gas Combined-Cycle Standards Under 111(d)

For existing natural gas units, EPA proposes that combined-cycle units with a capacity of greater than 300 MW and operating at a capacity factor of greater than 50% achieve a performance standard of 1,000 lb. CO_2/MWh (or their current permit standard), followed by (1) operating at less than a 50% capacity factor (presumably, according to EPA's modeling, beginning in 2035), (2) achieving a 12% emissions rate reduction (based on cofiring 30% low-GHG hydrogen) beginning in 2032 and increasing that to an 88.4% emissions reduction (based on cofiring 96% low-GHG hydrogen) beginning in 2038, or (3) achieving an 88% emissions reduction based on 90% CCS by 2035.

The hydrogen cofiring option, even if it were adequately demonstrated (see Section XII for a discussion of why hydrogen cofiring and CCS are not adequately demonstrated), is projected to be extremely challenging and expensive for Duke Energy to achieve, as discussed below in Section VIII. Additionally, CCS has not yet been adequately demonstrated on existing gas units in the U.S. and would only be able to be installed at sites with appropriate geology or if a system of pipelines to transport CO_2 to sequestration sites is developed and permitted.

For existing gas units over 300 MW, keeping capacity factors below 50% would carry its own set of challenges. Critically, to maintain reliable energy, the capacity and energy provided by those existing gas units that would otherwise operate above 50% would need to be replaced. The most cost-effective replacement to provide both dispatchable capacity and energy would most likely be new gas turbines, for which EPA proposes, once again, not adequately demonstrated, extremely costly, and difficult-to-implement hydrogen cofiring or CCS.

Importantly, EPA's proposal is unclear as to when the option for existing gas units to limit capacity factor to 50% takes effect. The agency apparently assumed in its modeling in the Regulatory Impact Analysis for the proposal that this would occur starting in 2035, but this needs to be clarified. Duke Energy does not believe the compliance date for a lower capacity factor should start earlier. As noted above, if existing turbines were limited to a 50% capacity factor, replacement capacity would need to be built, and given the need for new capacity to be built to replace retiring coal in the 2024-2030 time frame, this compliance date does not need to be earlier as it would make an already tight permitting and construction timeline even more difficult. In fact, based on Duke Energy's modeling, existing natural gas units' capacity factors are not projected to fall below 50% until the 2040s due to the timeline for permitting and installing replacement generation, as well as the time required for permitting needed infrastructure to support replacement generation like pipelines and transmission. Therefore, the date for existing natural gas to achieve a capacity factor less than 50% should be moved out until after 2040.

C. Dual Fuel Units

An important unit configuration that EPA did not address in the proposal and its development of BSER is that it is very common for some natural gas combustion turbines to also use fuel oil for grid reliability when gas is not available (typically during winter peaks).[43] Duke Energy currently has 21 existing combined-cycle units that rely on fuel oil as a backup fuel source, including several that are affected by the proposed EPA rule.

Fuel oil has a higher carbon content than natural gas and as a result its CO_2 emission rate is higher. However, given that fuel oil is used only in the case of urgent reliability needs when natural gas is not available (typically winter peaks), its emissions should be exempted from the emissions requirement of the proposed rule, or subjected to an emission limitation appropriate for oil-fired combustion turbines. If EPA intends to regulate CO_2 emissions from such dual-fuel or oil-fired combustion turbines, EPA needs to first take comments on any proposed standards for dual-fuel units and units that only combust fuel oil and then finalize a BSER for these units in a subsequent rulemaking.

EPA should be aware of a major challenge in including such units in requirements to cofire hydrogen; that is, to accommodate hydrogen, manufacturers would have to provide a burner for CTs that can burn three fuels (i.e. hydrogen, fuel oil and natural gas). However, only one of three major gas turbine manufacturers has a proven burner design to accommodate three fuels. For existing units, even if three-fuel burners are available, burner changeouts require a large and lengthy maintenance outage.

VIII. Comments Related to Hydrogen Production and Availability

A. Duke Energy’s View of Hydrogen Production and Availability

According to DOE’s Pathways to Commercial Liftoff report published in April 2023, “clean hydrogen production for domestic demand has the potential to scale from < 1 million metric ton per year (MMTpa) to ~10 MMTpa in 2030. Most near-term demand will come from transitioning existing end-uses away from the current ~10 MMTpa of carbon-intensive hydrogen production capacity. If water electrolysis dominates as the

[43] In addition, in the proposal, EPA did not specifically address units that combust fuel oil as their only fuel. Therefore, because there was not an opportunity to comment on such standards, it is assumed they would not be included in the final rule.

production method, up to 200 GW of new renewable power would be needed by 2030 to support clean hydrogen production."[44]

The current production of clean hydrogen is minuscule – less than 1 MMTpa – and it is very optimistic to believe that sufficient volumes of clean hydrogen with a carbon content of no more than 0.45 kg CO_2e/kg hydrogen would be available by 2032 to support cofiring in the country's natural gas-fired combined-cycle fleet. For example, the Electric Power Research Institute (EPRI) projects that 160 GW of existing natural gas-fired combined-cycle units will be subject to the rule (units greater than 300 MW capacity and with at least a 50% capacity factor in 2021). If these 160 GW were to fire a 30% volumetric-based blend of low-GHG hydrogen and natural gas (assuming a 75% capacity factor), the required low-GHG hydrogen needed to support generation would be approximately 7 million metric tons (7 MMT).[45] This demand would be more than seven times the current production of clean hydrogen, and 70% of the total current (2021) domestic hydrogen production of 10 million metric tons (10 MMT), of which the vast majority (95% plus) is not "clean" hydrogen but high CO_2 intensity hydrogen. To achieve a 96% blend, clean hydrogen production would need to increase again by at least sevenfold (if available) above the 2032 projection to meet increased combined-cycle demand between 2032 and 2038.

Although it is extremely unlikely that the U.S. clean hydrogen supply can match the need for blending hydrogen into the existing natural gas combined-cycle fleet by 2032, over time a real potential competition for clean hydrogen could result from the diversion of significant volumes of clean hydrogen to the power sector due to the proposed rule. For example, DOE's Pathways to Commercial Liftoff report states that first-phase, near-term expansion (2023-2026) of clean hydrogen will begin with industrial and chemicals use cases, including ammonia production and oil refining.[46] The second phase (2027-2034) of industrial scaling will drive clean hydrogen utilization in transportation, especially in heavy-duty trucks, aviation fuels and maritime fuels. Longer term, DOE states that a self-sustaining, commercial market for hydrogen post-production tax credit (PTC) expiration will be driven by falling delivered costs due to the availability of low-cost clean electricity, equipment cost declines, reliable and at-scale hydrogen storage, and high use of distribution infrastructure, including dedicated hydrogen pipelines.

DOE's Liftoff report shows that the IRA's production tax credit pulls forward the projected breakeven point for most of these use cases – refining, ammonia production, steel, heavy-duty trucking – into the 2020s and 2030s. However, the breakeven timing

[44] https://liftoff.energy.gov/clean-hydrogen/.

[45] Electric Power Research Institute Comments on the U.S. Environmental Protection Agency's "New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule" Docket ID: EPA-HQ-OAR-2023-0072, August 2023, pg. 12 ("EPRI comments").

[46] Department of Energy, "Pathways to Commercial Liftoff: Clean Hydrogen," March 2023, p. 2.

for both 20% and 100% combustion for firm power generation remains in the beyond-2040-time frame.[47]

With limited supply in the 2030s, EPA's proposed regulatory requirement could delay the adoption of clean hydrogen by these industrial and transportation markets and other uses that would have better financial and greater decarbonization benefits in the near term. For example, DOE's U.S. National Clean Hydrogen Strategy and Roadmap shows clean hydrogen development coming in waves based on (for each use case) (1) lack of low-carbon alternatives, (2) state and federal policy momentum, and (3) industry momentum, including private sector investment. Heavy-duty trucks, transit buses, refining, and forklifts are shown in the first "wave," while use for power generation and energy storage is shown in the second and third "waves." For example, displacing diesel fuel (used for heavy transport) instead of natural gas for power generation provides a nearly 40% greater greenhouse gas reduction.[48]

While Duke Energy supports the development of clean hydrogen production through DOE's hydrogen hubs program and is in fact a member of the Southeast Hydrogen Hub coalition that has proposed a green hydrogen network in the Southeast, the DOE's $7 billion funding opportunity alongside proposed applicant capital investment levels in hubs does not come close to supporting the amount of new hydrogen production and infrastructure needed to comply with the hydrogen cofire rule prior to the 2040s.[49]

B. Transportation Issues Related to Hydrogen

Existing natural gas pipelines are not capable of handling hydrogen in the amounts necessary for compliance with EPA's proposal. First, from a regulatory perspective, the vast majority of pipelines currently do not have hydrogen as an approved gas quality constituent in their tariffs. Thus no hydrogen volumes of significance could even be transported until any potential tariff changes enabled such blending. Such tariff changes would likely be controversial and potentially litigated. Hydrogen is currently not transported in existing natural gas infrastructure for a multitude of reasons, which include safety and optimizing limited pipeline capacity.

[47] *Id.* p. 39.

[48] According to the U.S. Energy Information Administration, natural gas emits on average 116.65 lb.CO_2/mmBTU, while diesel fuel emits 163.45 lb.CO_2/mmBTU, a difference of 40%.

[49] As discussed on page 30, it is estimated that to supply 30% cofiring to the projected U.S. fleet of natural gas-fired combined-cycle power plants subject to the proposed rule would require 7 million metric tons of "low-GHG" hydrogen. According to DOE, the Regional Clean Hydrogen Hubs program will "establish six to 10 regional hubs across America … The hubs will create networks of hydrogen producers, consumers, and local connective infrastructure to accelerate the use of hydrogen … The H2Hubs will form the foundation of a national clean hydrogen network …" EPRI projects (using DOE data) that the hydrogen hubs will produce (at the upper end) 0.41 million metric tons per year of hydrogen (pg. 49 of EPRI comments). In other words, the hydrogen hubs program is a critical step but is not envisioned to be the "national clean hydrogen network" that would be needed to supply hydrogen to all large existing and new natural gas turbines.

Second, any blending in existing natural gas infrastructure is unproven and would require more capacity due to hydrogen's lower density. Moreover, these pipelines do not only serve electric generating units, but also provide natural gas to local distribution companies (LDCs). LDCs provide this gas to industrial, commercial and residential customers. The gas-burning equipment of these customers, such as residential water heaters, stoves and furnaces, was never intended to combust natural gas mixed with hydrogen and could present clear technology and safety issues.

Third, existing natural gas transmission pipelines did not contemplate hydrogen blends. Thus there are metallurgy unknowns and potential associated material degradation and leakage due to hydrogen's properties. Importantly, in the company's service territories, current natural gas pipeline capacity is generally fully subscribed on existing interstate and intrastate pipelines. Further, a greater volume of hydrogen is required to deliver the same amount of energy as natural gas. Given these factors, new hydrogen pipelines would need to be constructed. There are currently no hydrogen pipelines operating in Duke Energy's electric service territories. Development, permitting and construction of a new hydrogen pipeline system would be a massive, time-consuming undertaking. This is discussed further above.

Additionally, hydrogen would need to be stored in order to meet fluctuations in energy demand; however, the only commercially proven underground storage method is via salt domes. There are no salt formations to support this technology in any of the company's service territories – they exist only on the Gulf Coast.

C. Critical "Low-GHG" Hydrogen Details

The EPA is proposing that hydrogen qualifies as low-GHG hydrogen if it is produced through a process that results in a GHG emission rate of less than 0.45 kilograms of CO_2 equivalent per kilogram of hydrogen on a well-to-gate basis consistent with the system boundary established in the Internal Revenue Code section 45V (Credit for Production of Clean Hydrogen) of the IRA. According to EPA, hydrogen produced by electrolysis (splitting water into hydrogen and oxygen) using non-emitting energy sources such as solar, wind, nuclear and hydroelectric power can produce hydrogen with carbon intensities lower than 0.45 kg CO_2e/kg H_2, which could qualify as low-GHG hydrogen for the purposes of this proposed BSER.

Notably, the Department of the Treasury has yet to finalize guidance for implementation of the 45V production tax credit. Critical details including potential restrictions related to additionality, deliverability and hourly time-matching for grid-connected green hydrogen production from electrolysis have yet to be determined.[50] We believe that the final determination of these details will greatly influence the cost and timing of green hydrogen becoming available.

[50] https://www.nrdc.org/sites/default/files/2023-04/nrdc-catf-memo-ira-45v-legal-necessity-3-pillars-20230410.pdf.

Proponents of additionality would require an electrolyzer operator to draw electricity for hydrogen production from new clean energy sources, potentially with some exceptions for facilities that are repowered, undergo uprates that increase the rate of electricity production, or provide electricity that would otherwise not have been delivered to customers due to excess variable renewable power on the grid at periods of high renewable production and low electricity demand (known as curtailed electricity). A strict additionality requirement would eliminate the potential for clean hydrogen production from existing carbon-free nuclear.

Deliverability would require electrolyzers to source clean electricity from within their same operating region. Hourly time-matching would require electrolyzers' electric consumption to match clean energy production down to the hour. For example, an electrolyzer using solar power would need to ramp down overnight to match the solar array's production curve. Some groups have advocated for a phase-in to this requirement.

To reach net-zero emissions economy-wide by 2050, it will be necessary to transition all hydrogen production to very low- or zero-emission production pathways. However, the clean hydrogen industry is very nascent. Requiring electrolyzer projects to develop new clean energy sources and comply with complex hourly matching requirements, which are not common practice for renewable energy procurement today, has the potential to delay the development and deployment of clean hydrogen projects, which would further limit the supply and increase the cost of green hydrogen that would be needed to achieve EPA's proposed hydrogen cofiring requirements.

However, under the Clean Air Act, production of hydrogen is not part of the source category for which EPA has proposed regulations under sections 111(b) and (d). If EPA wishes to regulate greenhouse gases from hydrogen production, it should undertake a separate rulemaking under section 111 by gathering information, proposing and taking comment before finalizing a rule.

D. Definition of "Low-GHG" Hydrogen

Under the Clean Air Act, EPA cannot define "low-GHG hydrogen" as part of this rulemaking without proposing and promulgating a separate "hydrogen production new source performance standard." Under this standard, EPA should expand its definition beyond what it has proposed here to include clean hydrogen production from diverse low-carbon sources. First, EPA should clarify the potential sources of hydrogen under this rule include nuclear. While EPA has said that hydrogen produced from nuclear power can meet its 0.45 kg/kg standard, its proposal is not clear that hydrogen from existing and new nuclear should be considered "low GHG" for purposes of this rule.

EPA should also allow for other forms of hydrogen such as the methane pyrolysis process where hydrogen is formed from natural gas. The process does not produce CO_2 and instead converts the carbon to a solid form that can be safely stored.

EPA's proposal is also inconsistent with DOE's definition of clean hydrogen under the Infrastructure Investment and Jobs Act. DOE establishes a target for "clean hydrogen" well-to-gate life cycle greenhouse gas emissions of ≤4.0 $kgCO_2e/kgH_2$. According to DOE, this target is also consistent with the IRA's definition of "qualified clean hydrogen" and supports clean hydrogen production from diverse low-carbon technologies.[51]

As EPA acknowledges, the 45V credits "range from \$3/kg H_2 for 0.0 to 0.45 kilograms of CO_2-equivalent emitted per kilogram of low-GHG hydrogen produced (kg CO_2e/kg H_2) down to \$0.6/kg H_2 for 2.5 to 4.0 kg CO_2e/kg H_2 (assuming wage and apprenticeship requirements are met). Projects with GHG emissions greater than 4.0 kg CO_2e/kg H_2 are not eligible." EPA therefore has no reason to finalize a standard for 0.45 kg CO_2/kg H_2. It should use the same standard that DOE uses – 4.0 kgCO2e/kgH_2. As DOE states, "fossil fuel systems that employ high rates of carbon capture or other thermal conversion processes … are all generally expected to be capable of achieving less than or equal to 4.0 $kgCO_2e/kgH_2$" and "a steam methane reformer with ~95% carbon capture and sequestration (CCS) could achieve ~4.0 kgCO2e/kgH2 well-to-gate emissions by using electricity that represents the average U.S. grid mix and ensuring that upstream methane emissions from the natural gas supply chain do not exceed 1%."[52]

EPA should also consider a more achievable standard for hydrogen production in the early years to allow the technology to develop. This could become more restrictive over time as the technology for producing hydrogen in a clean manner is further developed.

IX. Comments Related to CCS

A. Duke Energy's Perspective on Carbon Capture and Sequestration's State of Technology

While carbon capture and sequestration technologies and applications are experiencing increased interest (due to increased federal incentives), there are numerous challenges with widespread installation (including on natural gas-fired combustion turbines), with transportation and with siting and permitting sequestrations. Duke Energy is leaning in to help develop CCS. As mentioned above, earlier in 2023, we were selected by DOE for award negotiations on a FEED study at the company's IGCC facility in Edwardsport, Indiana.

Although CCS has potential, and, as stated above, Duke Energy supports the development and deployment of CCS for power generation, at this point, no commercial power generation units in the U.S. utility industry are currently operating using the technology.[53] While the Petra Nova carbon capture demonstration project did operate

[51] https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-production-standard-guidance.pdf.

[52] U.S. Department of Energy, Clean Hydrogen Production Standard (CHPS) Guidance.

[53] As noted above, the coal-fired Boundary Dam power plant is operating with CCS in Canada.

on a portion of the flue gas from a coal plant in Texas from 2017 to 2020 and may start back up in the near future as a result of tax credits made available under the IRA, CCS has not been demonstrated on a natural gas combined-cycle power plant in the U.S. Flue gas from natural gas units is quite different from that of coal units, so developing that technology fully will take more demonstrations.

B. Challenges with Siting and Permitting CCS Sequestration Sites

Other challenges related to CCS stem from siting and permitting sequestration sites. Section V discusses why CCS is not considered adequately demonstrated and a major constraint is that obtaining a Class VI permit under the Safe Drinking Water Act to inject CO_2 is a complicated and time-consuming undertaking. First, geologic studies are needed to discern if a site can even safely receive CO_2, as sequestration and storage potential is not evenly distributed across the U.S. Then, the permit application calls for complete site characterization, modeling of CO_2 migration, well construction, well testing, monitoring, financial demonstrations, and risk analysis for emergency and remediation situations.

Class VI well applications can take up to six years to develop and for EPA to process and approve.[54] Of the more than 700,000 well permits issued under the underground injection (UIC) program, only six are for Class VI wells. Unfortunately, four of those permits expired before any well construction began. Only two Class VI wells are active as of mid-June 2022. Both are located at the Archer Daniel Midland's ethanol plant in Macon County, Ill. And, for both, the time from application submission to issuance was approximately three years, though, generally, the entire study and permitting process can take up to six years. (Archer Daniels Midland CCS1: application submitted December 2011, permits effective February 2015; Archer Daniels Midland CCS2: application submitted July 2011, permits effective September 2014.)[55]

On July 7, 2023, EPA announced a comment period on its intent to issue two carbon storage injection well permits for an ammonia fertilizer production facility in Indiana. The permits were requested by Wabash Carbon Services, which filed its applications about two years prior. EPA will need additional time to review and address all public comments before making a final decision on whether to grant these permits. Depending upon the complexity of this process, it is not clear when EPA will issue these Class VI permits.

Carbon sequestration sites can face further regulatory obstacles, including but not limited to Clean Air Act and Clean Water Act permits, consultations under the Endangered Species Act (ESA) and reviews under the National Environmental Policy Act (NEPA). The precise mix of environmental permits and reviews needed for a

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[54] Mayer Brown, April 2022, Carbon Capture Sequestration Utilization and Storage Projects and US Federal Environmental Laws | Perspectives & Events | Mayer Brown.

[55] Mayer Brown, June 2022, Carbon Capture, Utilization, and Storage: Class VI Wells and US State Primacy: Perspectives & Events.

particular project will vary based on project-specific details. In addition to the above, the Council on Environmental Quality (CEQ) recently issued new guidance on the responsible deployment of CCS technologies, including direction on incorporation of environmental justice and equity considerations, meaningful public engagement and tribal consultations, and support for union job creating projects.[56]

Sequestering CO_2 in the United States in subsurface geological formations presents a unique property law issue for pore space ownership. A single project may need to lease pore space that numbers in the thousands to tens of thousands of acres. CCS projects may need to work extensively to receive approval from many landowners and commercial entities that have varying ownership regimes of joint ownership and split ownership of mineral and surface estates. This is further complicated by the fact that many owners in an area may be unwilling to lease their pore space rights.[57] There is uncertainty in many states' regulatory frameworks for CCS leasing and eminent domain rights and CCS projects may be dealing with legal recourse that could further affect the viability of projects. Project viability depends on legal and regulatory certainty.

X. Issues Related to Approval for and Permitting of Hydrogen and CO_2 Pipelines

As with natural gas pipelines, obtaining approval of and permitting for hydrogen and CO_2 pipelines are likely to be challenging projects. Federal approvals will likely be required where pipelines cross state lines or are otherwise involved in interstate commerce. Currently for interstate natural gas pipelines, under Section 7(c) of the Natural Gas Act (NGA), companies must obtain a certificate of public convenience and necessity from the Federal Energy Regulatory Commission (FERC) to construct any facilities for natural gas transportation across interstate lines. No statute expressly provides for federal regulation of the construction or siting of interstate hydrogen pipelines, or their rates or services. However, three existing statutes could be construed to confer such jurisdiction. These include the Natural Gas Act, the Interstate Commerce Act, and the Interstate Commerce Commission Termination Act. Hydrogen is most logically classified as "artificial gas" under the Natural Gas Act, over which FERC has jurisdiction only if it is blended with "natural gas" on interstate pipelines. Alternatively, FERC could assert more expansive jurisdiction over hydrogen as "natural gas," but this would be susceptible to judicial challenges. Similarly, siting of new CO_2 pipelines is not regulated by any federal agency; such siting is currently left to the states. The Pipeline and Hazardous Material Safety Administration (PHMSA) has statutory authority over CO_2 pipeline safety.[58]

In addition, natural gas, hydrogen and CO_2 intrastate pipeline projects may require Certificate of Public Convenience and Necessity (CPCN) approval from the state public utility commission(s) depending upon the pipeline's length, pressure, and diameter and/or the plans for cost recovery. The CPCN process varies by state but typically

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56 Id.

57 Global CCS Institute, Brief-Pore-Space-Rights-5.24-12.pdf, May, 2012.

58 See CARBON DIOXIDE PIPELINE REGULATION (eba-net.org).

includes required public notifications and stakeholder meetings and may include public and adjudicatory hearings.

In addition, a Section 404 Nationwide Permit 12 (NWP12) for Utility Line Activities will need to be obtained from the U.S. Army Corps of Engineers (USACE) for any pipeline project impacts to streams and wetlands. As part of the USACE approval, wetland mitigation credits may also be required to be obtained for any permanent impacts to wetlands and for any permanent conversion of forested wetlands to maintained pipeline right of way. In addition, USACE Section 10 permits will be required for any crossings of navigable waterways. State 401 Water Quality Certification (WQC) permitting may also apply to isolated wetlands and streams impacted by the project, with the potential for mitigation requirements. As part of the USACE permitting process, Section 7 ESA and 106 National Historic Preservation Act (NHPA) clearances are required related to Waters of the U.S. (WOTUS) impacts of the project.

Further, any restrictions and conditions resulting from U.S. Fish and Wildlife Service (USFWS) and State Historic Preservation Office (SHPO) consultations, survey activities and associated authorizations will apply to project construction activities. Consultations with agencies responsible for the protection of state threatened, endangered or otherwise protected species are also required and may result in additional project surveys and conditions. Depending on a given project's route, requirements may include permits for crossings of federal lands from the Bureau of Land Management (BLM). Construction-specific state permits can include state Erosion and Sediment Control (E&SC) and hydrostatic pressure test water discharges. Local authorizations required may include but not be limited to floodplain, land disturbance, earth-moving, clearing, building, and access drive permits. Any local noise ordinances must also be considered for construction activities. Projects that include horizontal directional drilling (HDD) create a potential for Inadvertent Returns (IR) of drilling mud, a particular challenge when HDD is used to install pipelines under waterways. Site-specific IR Contingency Plans will be required for each HDD location.

Obtaining permits for new pipelines has become increasingly litigated, especially within appeals courts in the company's service territories. Without meaningful permitting reform, there is a heightened execution risk of permitting, constructing and ultimately placing into service the required new pipeline infrastructure of the proposed rule.

XI. Reliability Concerns

A. Electric Utilities Have a Critical Mission of Maintaining Reliability

Regulated electric utilities are required to provide reliable electric service by state law and state public utility commission regulation, as well as FERC and the North American Electric Reliability Corporation (NERC) requirements to protect the bulk power system. This proposal's provisions constrain companies' ability to operate in a way that maintains reliability, increasing reliability risks. For example, reliability could be threatened if a company is called upon to dispatch a coal unit that has reached its 20%

capacity factor limit or is an existing natural gas unit that has reached its 50% capacity factor limit. Also, as discussed above, there are significant risks with EPA's proposed requirements for use of hydrogen and CCS; if permits and construction for such installations are not completed in the time periods specified in EPA's proposal, needed units could be kept off the grid.

In addition, Duke Energy operates units in MISO and PJM where it has obligations to make generating assets available for use. Under MISO and PJM rules, we must offer prices for energy from each of our units and, based on these prices, MISO and PJM decide whether to dispatch our units. Limitations proposed by EPA in this regulation can threaten to upend the market constructs that determine unit dispatch in RTOs like MISO and PJM.

B. Administrative Compliance Orders Are an Ill-Suited Means of Addressing Reliability Issues

EPA suggests that to aid affected sources in implementing the standards and to address "genuine risks to electric system reliability," the agency intends "to exercise[e] its enforcement authorities to ensure compliance while addressing genuine risks to electric system reliability."[59] Specifically, EPA states that it is appropriate to rely on its enforcement discretion to agree to negotiated resolutions, including administrative compliance orders (ACOs), "to provide accommodations for potential isolated instances in which unanticipated factors beyond an owner or operator's control, and ability to predict and plan for, could have an adverse, localized impact on electric reliability."[60] EPA asserts that the agency's proposed reliance on ACOs is intended "to provide confidence . . . with respect to electric reliability," but, for several reasons, this approach provides no meaningful assurance to sources to protect grid reliability.[61]

First, those generic promises provide no comfort during an energy crisis because they would be offered only after the fact to resolve any alleged violations. Therefore, the possibility of future enforcement discretion and ACOs will not help a power generator decide in the moment whether to keep running and risk a violation or shut down, risking grid reliability and affecting our customers.

Second, ACOs are enforcement actions that carry negative implications and the potential for significant civil penalties. Current maximum penalties under the Clean Air Act are now set at over $100,000 per day per violation, and facilities cannot just accept that risk in the hope EPA will either exercise enforcement discretion or ask for a lower penalty. Moreover, citizen groups are unlikely to exercise the same discretion, even if EPA decides a low (or no) penalty is appropriate.

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[59] 88 Fed. Reg. at 33,401.

[60] *Id.*

[61] *Id.*

Finally, ACOs are typically intended to resolve relatively short-term noncompliance events that can be remedied and that do not reflect a fundamental inability to comply. As such, they are ill-suited for addressing long-term challenges associated with unachievable standards because they do not protect against injunctive relief that would require compliance with a standard that may be impossible to meet. A fundamental inability to comply due to the promulgation of unachievable standards is significantly different from "isolated instances in which unanticipated factors [are] beyond an owner or operator's control."

Accordingly, it is incumbent on EPA to include reliability assurance mechanisms – both short- and long-term to address various circumstances – in the final rule to provide electric utilities with a genuine compliance solution in situations where affected sources must run to maintain the power grid.

This reliability assurance mechanism must go beyond the provision it currently proposes for grid emergencies (that power system operators can apply for an ACO to allow deviation from the requirements of the rule only when a grid emergency has been declared). Grid reliability must be planned years in advance to balance generation and electric demand every second of every day. EPA's proposed mechanism that essentially amounts to an enforcement waiver when a system emergency has been declared does not ensure grid reliability. The needed mechanism would provide short- and long-term waivers to ensure grid reliability well *before* grid emergencies. The instances where waivers are necessary could include delays in technology and infrastructure development and deployment, permitting and regulatory delays, transmission constraints and delays, supply chain delays, and other factors. EPA's final rule should provide a reliability assurance mechanism that provides flexibility in case of the delays mentioned above well before a grid emergency is declared. It is our understanding that a group of ISOs/RTOs is providing comments with suggested modifications that would help mitigate the reliability impacts of EPA's proposal.

XII. Legal Considerations and Arguments

A. A Best System of Emission Reduction Must Be Adequately Demonstrated and the Standard Must Be Achievable

In this proposed action, EPA establishes novel multi-phase standards under section 111(b) of the CAA that would apply to new natural gas combustion turbines. These standards, which EPA refers to as "Phase 2" and "Phase 3," are established based on the significant incorporation of low-GHG hydrogen and CCS. However, EPA's evaluation of the best system of emission reduction (BSER) is flawed, as it is inconsistent with the plain language of the Act. *National Lime Ass'n v. Environmental Protection Agency*, 627 F.2d 416, 430 (D.C. Cir. 1980).

The Act requires EPA to establish federal standards of performance for new sources within stationary source categories. 42 U.S.C. § 7411(b)(1)(B). The Act defines "standard of performance" 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." 42 U.S.C. § 111(a)(1) (emphasis added). EPA bases its proposed standards for new natural gas-fired units on low-GHG hydrogen cofiring and CCS. Specifically, any natural gas-fired units operating at base load that are constructed after the promulgation date of the proposed rule would be required to meet standards based on low-GHG hydrogen cofiring or aggressive CCS starting in 2032 or 2035, respectively.[62]

As discussed below, however, hydrogen cofiring and CCS are not adequately demonstrated as that term has been interpreted by the courts, and the standards based on these technologies are not achievable.[63] Accordingly, EPA may not rely on these technologies to establish its standards. Congress' recent passage of the IRA, which includes provisions to support hydrogen and CCS technology development and deployment through the award of tax credits to companies that use these technologies, only underscores the fact that they are not adequately demonstrated technologies. It was precisely because hydrogen and CCS are neither cost-effective nor have been adequately demonstrated that Congress chose to provide incentives to stimulate development of these technologies. Moreover, the Infrastructure Investment and Jobs Act, which provided grant money specifically for demonstration projects for hydrogen and CCS, does not provide grant funding for commercially available technologies (wind, solar) but rather for more nascent technologies, including $8 billion for hydrogen hub demonstrations and approximately $12 billion for CCS. There is no guarantee that any of these demonstration projects will move to commercial operation or how the technology may evolve as a result of these demonstrations.

As the U.S. Court of Appeals District of Columbia Circuit (D.C. Circuit) – the court of exclusive review for NSPS – has made clear, EPA may not engage in prognostication when setting the best system of emission reduction. Although EPA may make a projection based on existing technology, that projection is "subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry." *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973). EPA cites *Portland Cement* for the proposition that technology need not be in actual routine use somewhere. 88 Fed. Reg. at 33,275. However, EPA fails to address that portion of the D.C. Circuit's holding, which immediately follows, wherein the court expounded that the "essential question [is] . . . whether the technology would be available for installation in new plants," and to be considered "available," "the technology may not be one which constitutes a purely theoretical or experimental means of preventing or controlling air pollution." *Portland Cement*, 486 F.2d at 391. And if actual tests are not relied upon to establish the standard, "but instead a prediction is made, 'its validity . . . rests in the reliability of [the]

[62] With the hydrogen cofiring requirements becoming more stringent in 2038.

[63] EPA's proposed Section 111(d) standards for existing coal-fired units are also based on application of CCS well into the future.

prediction and the nature of [the] assumptions.'" *Id.* at 392 (citing *International Harvester v. Ruckelshaus*, 478 F.2d 615, 642 (D.C. Cir. 1973)).

The record does not support that a system based on low-GHG hydrogen and CCS is adequately demonstrated, nor that the proposed standards are achievable by the electric utility industry as a whole, both of which are fundamental statutory requirements.[64] *National Lime Ass'n*, 627 F.2d at 431. "It is the system which must be adequately demonstrated and the standard which must be achievable." *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973). Accordingly, the answer to this "essential question" of whether the technologies relied upon by EPA – low-GHG hydrogen cofiring and CCS – are adequately demonstrated is, unequivocally, no.

B. Low-GHG Hydrogen Cofiring and CCS Are Not Adequately Demonstrated

None of the projects seeking to test hydrogen blending in natural gas-fired EGUs, which EPA discusses in the preamble to the proposed rule, are in commercial operation. Although there are pilot and demonstration projects, they have been limited in duration and are nowhere near the scale required by this proposed rule. The lack of long-duration operation while combusting hydrogen at scale is a critical flaw.[65]

Moreover, EPA has proposed a very low carbon-content hydrogen – and, it must be noted, without specifically promulgating a performance standard for low-GHG hydrogen – that further calls into question the probability of adequate hydrogen supply to meet the proposed rule. The current global production of clean hydrogen is minuscule, [66] and it is extremely optimistic to believe that a sufficient amount of clean hydrogen with a carbon content of 0.45 kg CO_2e/kg hydrogen, as required by EPA's proposed rule, would be available by 2032 to support cofiring in the portion of the nation's natural gas-fired combined-cycle fleet subject to the proposed rule. Assuming a 75% capacity factor, it is estimated that if the current U.S. fleet of natural gas-fired combined-cycle units projected by EPRI to be subject to the proposed rule (160 GW) were to fire a 30% volumetric-based blend of hydrogen and natural gas, the required hydrogen to support

[64] Moreover, any technology on which a standard is based must be capable of being applied at the power plant. In most cases, H_2 pipelines will need to be constructed to supply fuel to the facility to comply with the hydrogen pathway, and carbon dioxide pipelines will need to be installed to sequester CO_2 at suitable sequestration sites under the CCS pathway. Section 111 does not authorize EPA to mandate emission reductions that cannot be implemented at individual regulated stationary sources. *See* 42 U.S.C. § 7411(a)(1), (a)(3), (d)(1) (limiting BSER to those systems that can be put into operation at a building, structure, facility or installation).

[65] Firing hydrogen requires metal alloys that can withstand higher temperatures than for turbines firing just natural gas. Degradation of the metal alloys used in the high-temperature turbine components can happen over extended time periods and can be aggravated by cycling operation.

[66] Wood Mackenzie, "The Rise of the Hydrogen Economy," *available at* https://www.woodmac.com/market-insights/topics/hydrogen-guide/.

generation would be approximately 7 million metric tons.[67] This demand would represent total current (2021) domestic hydrogen production of 10 million metric tons,[68] of which the vast majority (95% plus) is not "low-GHG" hydrogen as proposed by EPA, but rather high CO_2-intensity hydrogen.[69, 70] Therefore, significant amounts of "low-GHG" hydrogen production would need to be developed.

Although there have been a limited number of successful test burns of hydrogen cofiring in existing natural gas power generation units, they have been at lower volumes and of short duration. Such demonstration projects include:

- At a natural gas combustion turbine at Georgia Power's 2.5-GW plant, McDonough-Atkinson cofired a 20% hydrogen blend at full and partial loads;
- At the Brentwood power plant, the New York Power Authority demonstrated the ability to cofire 44% "carbon-free" hydrogen blended with natural gas in a retrofitted combustion turbine; and
- The Cricket Valley Energy Center in New York is *planning* to demonstrate cofiring a 5% blend of hydrogen at a combined-cycle facility.[71]

The foregoing further shows that cofiring large amounts of hydrogen in natural gas turbines is not adequately demonstrated.

Recognizing this dearth of clean hydrogen production and use, EPA resorts to the contention that utilities have "announced *plans* to move to combusting 100 percent hydrogen in the 2035-2045 timeframe." 88 Fed. Reg. at 33,255 (emphasis added).

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[67] Electric Power Research Institute Comments on the U.S. Environmental Protection Agency's "New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule" Docket ID: EPA-HQ-OAR-2023-0072, August 2023, pg. 49.

[68] U.S. Department of Energy, "U.S. National Clean Hydrogen Strategy and Roadmap," *available at* https://www.hydrogen.energy.gov/pdfs/us-national-clean-hydrogen-strategy-roadmap.pdf.

[69] U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, "Hydrogen Production: Natural Gas Reforming," *available at* https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming.

[70] Although it is unlikely that clean hydrogen supply can match the need for blending of the natural gas combined-cycle fleet by 2032, a real potential negative impact could result from the diversion of significant volumes of clean hydrogen to the power sector due to the proposed rule. With limited supply, this proposed regulatory requirement could delay the adaption of clean hydrogen into markets and use cases that would have better financial and greater decarbonization benefits. For example, displacing diesel fuel (used for heavy transport) instead of natural gas provides a nearly 40% greater GHG reduction.

[71] U.S. Environmental Protection Agency, Hydrogen in Combustion Turbine Electric Generating Units Technical Support Document (May 3, 2023) at 9-10, *available at* https://www.epa.gov/system/files/documents/2023-05/TSD%20-%20Hydrogen%20in%20Combustion%20Turbine%20EGUs.pdf.

However, even characterizing these as “plans” is an overreach[72] and, in any event, aspirational plans to one day build and utilize a technology with no binding or enforceable requirements fall far short of what is required for a technology to be considered “adequately demonstrated.” This statement also fails to distinguish between capability and feasibility. Although some utilities have announced plans to procure turbines that are *capable* of combusting significant amounts of hydrogen, that fails to account for whether utilities have access to sufficient hydrogen supply and an infrastructure to provide that hydrogen, particularly low-GHG hydrogen. The statement EPA cites would only be compelling if EPA’s proposed standards merely required that utilities procure turbines that are capable of cofiring significant quantities of hydrogen.

There are myriad challenges associated with the use of hydrogen for utility-scale electricity generation in the time frame proposed by EPA, including a grossly inadequate hydrogen supply chain and a lack of infrastructure, especially hydrogen pipelines. There are almost 3 million miles of natural gas pipelines in the U.S.; by comparison, there are only approximately 1,600 miles of hydrogen pipeline.[73] Moreover, existing gas pipelines are not capable of handling hydrogen in the amounts necessary; a new hydrogen pipeline system would be needed.[74] EPA’s expectation that the supply and infrastructure to support the new standards will be in place in less than a decade is an illogical interpretation of the term “adequately demonstrated,” as it ignores costs, permitting and interconnection challenges, and siting issues while jeopardizing the reliability and affordability of the nation’s generating fleet.

With respect to CCS, although it has potential, at this point, no commercial power generation units in the U.S. utility industry are operating using the technology. Although the Petra Nova carbon capture demonstration project did operate on a portion of the flue gas from a coal plant in Texas from 2017 to 2020 and may start back up in the near future as a result of tax credits made available under the IRA, CCS has not been demonstrated on a natural gas combined-cycle facility. Flue gas from natural gas units is quite different from that of coal units, so developing that technology fully will take more demonstrations.

In addition to the capture technology, CCS poses a host of other challenges with respect to permitting its sequestration facility, pipeline siting and permitting, and

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[72] For example, EPA claims Duke Energy Corporation “outlined plans for full hydrogen capabilities throughout its future turbine fleet” but in fact cited a quote in the company’s 2022 Climate Report, which was merely listing modeling assumptions for a net-zero scenario analysis, not specific plans.

[73] U.S. Department of Energy, National Renewable Energy Laboratory, “Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology” (October 2022) at 13, *available at* https://www.nrel.gov/docs/fy23osti/81704.pdf.

[74] California Public Utilities Commission, “CPUC Issues Independent Study on Injecting Hydrogen Into Natural Gas Systems” (July 21, 2022), *available at* https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-issues-independent-study-on-injecting-hydrogen-into-natural-gas-systems#:~:text=However%2C%20blending%20more%20hydrogen%20in,avoid%20leaks%20and%20equipment%20malfunction (concluding hydrogen blends above 5% in natural gas pipelines “overall results in a greater chance of pipeline leaks and the embrittlement of steel pipelines.”).

community acceptance. (These issues are discussed in Section IX B.) No U.S. project has adequately demonstrated that it has overcome all these challenges; the Petra Nova demonstration project sent its captured CO_2 for enhanced oil recovery, which is a different type of sequestration site than the saline aquifers that would need to be used in other parts of the country, including the Midwest.

Although a number of entities are evaluating CCS applications, due primarily to increased federal incentives, specific commitments have not yet been made and it is unrealistic to believe that this technology can be applied on a nationwide basis, particularly to the broad gas-fired combined-cycle fleet. Importantly, as noted above, CCS has never been demonstrated on a combined-cycle facility and has not been demonstrated in a situation with the variable generation that the system will typically encounter as more renewable generation is added to the system.[75]

Although EPA lists a few CCS sites where short-term and/or slip-stream[76] operation has taken place, none of them show that CCS has been adequately demonstrated to support its proposed rule, particularly the 90% capture requirement. The agency's reliance on this limited number of experiences to extrapolate to an unachievable national standard is arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law considering the few demonstrations that have occurred and the case-specific suitability of CO_2 sequestration sites. *See National Lime Ass'n*, 627 F.2d at 430 (explaining promulgation of standards based upon inadequate proof of achievability defies the Administrative Procedure Act's mandate against unlawful agency action, 5 U.S.C. § 706(2)(A)). EPA confuses the appropriate standard-setting process inherent to an NSPS, which is set at a level that all new sources anywhere in the nation can reasonably meet, with the more stringent site-specific Best Available Control Technology (BACT) determinations carried out by state and local permitting authorities under the New Source Review program. The NSPS establishes a "floor" of lowest stringency – a standard that any source in the category can achieve – in determining BACT. Here, EPA conflates the two programs by establishing an NSPS for combustion turbines that cannot readily be achieved on a nationwide basis.

An examination of the technical information owners or operators of Class VI sequestration wells must submit to EPA or a state with an EPA-approved underground injection control program to obtain a Class VI permit to construct and operate a Class VI carbon sequestration well makes clear that the suitability of carbon sequestration sites is extremely case- and region-specific. Among other information, owners and operators must provide data on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including the location, orientation and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review; data on the depth, areal extent, thickness, mineralogy,

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[75] https://www.eenews.net/articles/epa-says-carbon-capture-is-within-reach-utilities-arent-biting/.

[76] "Slip-stream," in this case, is meant to describe the extraction of a fraction of the total exhaust flow into a pilot/test carbon capture system.

porosity, permeability and capillary pressure of the injection and confining zone(s); geomechanical information on fractures, stress, ductility, rock strength and in situ fluid pressures within the confining zone(s); information on the seismic history; and geologic and topographic maps and cross sections illustrating regional geology, hydrogeology and the geologic structure of the local area. In addition, owners and operators must submit maps and stratigraphic cross sections indicating the general vertical and lateral limits of all underground sources of drinking water (USDW), water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement and baseline geochemical data on subsurface formations, including all USDWs in the area of review. 40 C.F.R. § 146.82. If all sites/geologies were amenable to CCS, such extensively detailed geologic analysis would not be required.

To conclude, an adequately demonstrated system must be shown to be "reasonably reliable," "reasonably efficient" and reasonably capable of "serv[ing] the interests of pollution control without becoming exorbitantly costly in an economic or environmental way." *Essex Chemical Corp.*, 486 F.2d at 433. None of these requirements are met by the system EPA proposes in the proposed rule for either hydrogen or CCS. Weighing the agency's judgment against these limitations leads to the inexorable conclusion that the proposed standards were not the result of reasoned decision making. *Id.* at 434. Because low-GHG hydrogen cofiring and CCS "may [not] fairly be projected for the regulated future" and are not "within the realm of being adequately demonstrated," are "at a level that is purely theoretical or experimental" and "exorbitantly costly," the standards based on these technologies should not be finalized as proposed. *National Asphalt Pavement Ass'n v. Train*, 539 F.2d 775, 785-86 (D.C. Cir. 1976). Contrary to EPA's assertion, the agency's reliance on grant awards, loan guarantees, industry announcements to develop and plans to explore new technologies, demonstration projects, road maps for "plausible path[s] forward," examinations of pathways, and government initiatives to bring industry sectors together fails to meet the rigorous test of reasonableness established by the D.C. Circuit when determining whether an NSPS meets the statutory requirements of section 111(a)(1) of the Act. *See* 88 Fed. Reg. at 33,291-93, 33,312-13.

C. EPA May Not Rely on Multi-Part BSER to Circumvent the Statutory Requirement that BSER Be Adequately Demonstrated

With full knowledge that neither low-GHG hydrogen nor CCS is adequately demonstrated, EPA nevertheless seeks to establish standards now with the hope they will be adequately demonstrated a decade or more in the future through a "multi-part BSER." In defending its multi-part BSER approach, EPA cites *Portland Cement*, 486 F.2d at 391, for the proposition that EPA may determine the controls that qualify as BSER even if the controls require some amount of "lead time," defined by the court as "the time in which the technology will have to be available." 88 Fed. Reg. at 33,289. EPA goes on to claim that its phased implementation of the standards of performance in the proposed rule "ensures that facilities have sufficient lead time for planning and implementation of the use of CCS or low GHG-hydrogen-based controls[.]" *Id*. As authority for the multi-phased implementation approach contained in the proposed rule, EPA cites seven prior rulemakings – only five of which actually went into effect – that it purports serve as precedent. However, as discussed below, this claim is deeply misleading.

1. Analysis of Cited Rules that Went into Effect

Further examination of each of these five rulemakings that went into effect reveals that EPA's present overreach goes far beyond the "lead time for planning and implementation" that it has provided in any past standards of performance that may have actually gone into effect. First, for each of these rules, the maximum lead time provided was a mere fraction of what EPA provides in the proposal. Second, the purpose of the lead time in each of these rules was to account for practical and logistical impediments to compliance, such as the ability of retailers of affected sources to sell through inventory and the availability of trained personnel to install equipment, not, as EPA attempts in the proposed rule, to allow for longshot, crystal-ball predictions that pilot technologies will develop from a nascent state to utility-scale availability. Finally, and most importantly, the technology EPA relied on to establish BSER in each of these rules was well established and widely available at a commercial scale, in stark contrast to the current state of low-GHG hydrogen and CCS.

Rule	EPA's Determined Maximum Lead Time	BSER	Reason for Lead Time	State of BSER
Municipal Solid Waste (MSW) Landfills 81 Fed. Reg. 59,332 (Aug. 29, 2016)	30 months	Install and start up a gas collection and control system (GCCS) within 30 months after landfill gas emissions reach or exceed a nonmethane organic compound (NMOC) level of 34 Mg/yr. The GCCS could be a non-enclosed flare, an enclosed combustion device or a treatment system that	Time to procure and install controls. The 30 months of lead time could not have had anything to do with allowing technology to develop because the 30 months was triggered by a source's exceedance of the NMOC emission threshold, which could occur years into the future. If the 30 months of lead time had been intended to give time for the technology to develop, it would have been triggered by the effective date of the rule.	Adequately demonstrated; already used for initial 1996 NSPS. *Id.* at 59,341.

		processed the collected gas for sale or beneficial use. *Id.* at 59,334.		
Wood Heaters 80 Fed. Reg. 13,672 (Mar. 16, 2015)	5 years	Manufacturers must provide warranties, prohibit operation of catalytic heaters without a catalyst, and require operation according to owner's manual. *Id.* at 13,678 (room heaters) and 13,682 (central heaters).	Designed "to ease the transition" because "[t]he potential impact on this industry that is comprised of over 90 percent small businesses was a concern to the EPA[.]" *Id.* at 13,673. "Under this approach, Step 1 emission limits for these sources will apply to each source manufactured on or after the effective date of the final rule or sold at retail on or after Dec. 31, 2015. The approximately 8-month additional time for the retail sale requirement will allow retailers to sell their inventories of heaters that do not comply with the Step 1 emission limits." *Id.* at 13,677. "[W]e have included this [stepped compliance] approach in the revised subpart AAA and new subpart QQQQ in order to allow manufacturers lead time to develop, test, field evaluate and certify current technologies across their consumer product lines to meet Step 2 emission limits and in most cases to allow retailers to sell-through inventory." *Id.* at 13,676.	Adequately demonstrated Room heaters: 90% of catalytic and 18% of non-catalytic stoves already met the 5-year compliance limit. *Id.* at 13,686. Central heaters: 9 of 50 (18%) of EPA-qualified hydronic heater models already achieved 5-year compliance limit. *Id.* at 13,687.

Storage Vessels (Crude Oil and Natural Gas Production, Transmission and Distribution) 78 Fed. Reg. 58,416 (Sept. 23, 2013)	2 years	95% control requirement or an uncontrolled actual volatile organic compound emission rate of less than 4 tons per year (tpy). *Id.* at 58,417.	"[C]oncerns regarding the projections of potential combustor supply; the pace at which the combustor manufacturing industry can ramp up production and provide the necessary supply in the short-term; and the availability of trained personnel to install these devices on all affected facilities[.]"*Id*. at 58,420.	Adequately demonstrated; "overall supply of combustors appears to be adequate[.]" *Id*. at 58,420.
Petroleum Refineries 77 Fed. Reg. 56,422 (Sept. 12, 2012)	3 years	Includes requirement that flares be equipped with flow and sulfur monitors. *Id. at* 56,429.	"Given that many flares will become modified affected sources relatively quickly, owners and operators will be competing with one another for the services and products of a finite number of vendors who provide the necessary monitors and other equipment.…" "A phased compliance schedule will also allow owners and operators to minimize process interruption by coordinating the installation of monitoring equipment with process shutdowns or turnarounds." *Id*. at 56,450.	Adequately demonstrated; EPA recognizes in the preamble that vendors existed who were already supplying these monitors to the market, but the concern was just the rush caused by finalization of the rule would outpace the suppliers' ability to meet demand.
RICE 71 Fed. Reg. 39154 (July 11, 2006)	2- to 3-year compliance time frame and up to 6 years for certain emergency fire pump engines	EPA identifies averaging, banking and trading ("ABT") as the best demonstrated technology ("BDT"). *Id*. at 39,159.	EPA explained that the typical lead time "between order and installation of an engine" prevented a shorter deadline for installation for most engines. *Id*. at 39,162. EPA further determined that it was appropriate to exempt emergency fire pump engines from the six-	Unlike most technology-based standards, EPA does not make clear an adequately demonstrated showing. EPA notes "we believe that these ABT

			month deadline “to account for the fact that fire pumps have different timing requirements for the emission standards they have to meet” due to the fact that they are “self-regulated by the date of manufacturer.” *Id.*	provisions are essential elements in our determination that the final standards reflect best BDT. The flexibility provided by the ABT provisions allows the manufacturer to adjust its compliance for engine families for which coming into compliance with the standards will be particularly difficult or costly, without special delays or exceptions having to be written into the final rule.” *Id*. at 39,159.

2. Analysis of Cited Rules that Were Vacated

EPA also lists the Clean Power Plan (CPP) and the Clean Air Mercury Rule (CAMR) as supposedly precedent-setting rulemakings in support of the phased implementation approach in the proposed rule. Although these rules did provide longer lead times closer in duration to what EPA includes in the proposed rule (up to 15 years and 13 years, respectively), both were vacated on other grounds, such that this approach was never actually tested in court and cannot be relied upon as precedent-setting authority by EPA. Assuming arguendo, these two rules had been upheld, however, they are both easily distinguishable from the multi-part BSER approach EPA seeks to take in the proposed rule in an attempt to circumvent the Clean Air Act’s “adequately demonstrated” requirement.

3. Clean Power Plan

In the CPP, EPA required that affected EGUs begin to make reductions by 2022 and meet the final CO_2 emission performance rates or equivalent statewide goals by no later than 2030. 80 Fed. Reg. 64,662, 64,669 (Oct. 23, 2015). EPA determined that BSER was a combination of emission rate improvements and limitations on overall emissions accomplished through three so-called "building blocks":

1. Improving heat rate at affected coal-fired steam EGUs;
2. Substituting increased generation from lower-emitting existing natural gas combined-cycle units for generation from higher-emitting affected steam generating units; and
3. Substituting increased generation from new zero-emitting renewable energy generating capacity for generation from affected fossil fuel-fired generating units.

Id. at 64,667.

The CPP established an eight-year interim period (2022-2029), which was separated into three steps, 2022-2024, 2025-2027, and 2028-2029, each associated with its own interim goal. *Id.*

As with the five cited rules that actually went into effect, this lead time had nothing to do with the development of technology but rather practical considerations. In part, the CPP's phased compliance approach was in response to concerns about avoiding abrupt shifts in generation, which could compromise electric system reliability, impose unnecessary costs on customers, and require investments in more carbon-intensive generation, while diverting investment in cleaner technologies. *Id.* at 64,673. Additionally, unlike low-GHG hydrogen and CCS, the technology EPA relied on in establishing BSER – heat rate improvement projects, natural gas combined-cycle units, and wind and solar generation – had all been proven at utility scale and were commercially available at the time of the rulemaking.

4. Clean Air Mercury Rule

In 2005, EPA established mercury standards for coal-fired EGUs in two phases: a cap of 38 tons per year (tpy) starting in 2010, and a cap of 15 tpy in 2018. 70 Fed. Reg. 28,606 (May 18, 2005). The Phase I cap of 38 tpy reflected the co-benefit level achieved through application of SO_2 and NOx control technologies under the Clean Air Interstate Rule. EPA determined that, in 2005, information was "only adequate for us to conclude that such [mercury control] technologies are adequately demonstrated for use in the 2010 to 2018 time-frame to allow for compliance with the CAMR Phase II Hg cap." 70 Fed. Reg. at 28,618. EPA made this projection of future control availability by relying on the fact that then-current pilot-scale activated carbon injection (ACI) projects at power plants "should yield information that ought to be usable in implementing similar pilot scale projects at other facilities . . . . [and] allow companies to design full scale applications that should provide reasonable assurance that emissions limitations can be reliably achieved over extended compliance periods." *Id.* at 28,619. EPA further noted that other technologies (flue gas desulfurization with fabric filter baghouses) could achieve nearly the same levels of emission control and that permits had been issued that already relied on ACI. *Id.* at 28,614. In addition, EPA relied on a cap-and-trade program to assure itself that the standard would be achievable. *Id.* None of this applies to the proposed rule because there are no comparable, effective emission control technologies that are adequately demonstrated, and EPA has not proposed or evaluated a cap-and-trade program.

Moreover, the statements on which EPA relies fail to accurately describe the state of ACI technology at the time. In fact, ACI technology was substantially evolved by the time CAMR was promulgated, and the status of the technology cannot fairly be compared to the current state of low-GHG hydrogen and CCS technologies. The concept of introducing sorbents into a flue gas stream to control Hg emissions was not complicated, and by 2005, the technology was very close to being commercially deployable. A BSER based on an existing technology requiring little more than fine tuning to determine the optimum sorbent mix is vastly different from a multi-part BSER based on little more than a hope that the required technologies – technologies in which the electric utility industry has no long-term experience – will be available at the scale required upon commencement of each of the phases. Where ACI required only evolutionary improvements, revolutionary advancement is needed with nascent and largely unproven low-GHG hydrogen and CCS technologies.

A review of the Response to Significant Public Comments on the Proposed Clean Air Mercury Rule ("CAMR RTC Document") supports the conclusion that ACI technology was either already commercially available for utility use or well within reach:

- "[B]ased on control technologies currently in commercial use or proposed in permit applications, states such as Connecticut, Massachusetts, New Jersey, and Wisconsin have or will adopt limits that represent control efficiencies of 80 to 90 percent or more. . . . [T]hese levels can be achieved using the controls required for NOx and SO_2 reductions under the IAQR [Interstate Air Quality Rule] if the equipment maximizes mercury control. *Tuning for optimal mercury removal, absorbent improvements, and other enhancements* for multiple emissions control would be effective measures to improve mercury removal." CAMR RTC Document at 5-37 (emphasis added).

- "[A] number of states, including Massachusetts, New Jersey, Wisconsin and Connecticut, have already promulgated Hg reduction requirements. In some of these states, strict Hg reduction requirements are being imposed in the 2006 to 2008 timeframe, and compliance will require use of ACI or of another approach that will achieve similar levels of reduction. In developing these regulations, *the states have conducted evaluations that have lead [sic] them to conclude that activated carbon will be a commercially available option in this timeframe*." CAMR RTC Document at 9-58 (emphasis added).

- "Compliance with some of the state rules begins in 2008, consequently these facilities will have installed, tested and operated ACI systems long before the compliance date. By 2008, 15 boilers in Massachusetts, Connecticut, and New Jersey will be controlling Hg by more than 90 percent. . . . *Given this systematic evolution of the adaptation of activated carbon technology to the power sector, the commenter was confident that this technology will not just be available prior to 2010 but widely commercially available in time to facilitate compliance with a 2008 MACT standard.*" CAMR RTC Document at 9-74 (emphasis added).

- "*According to the Institute of Clean Air Companies, power plants already are bidding on or finalizing contracts for Hg control equipment.* Over 50 plants likely will be affected by the new rules finalized by the states of Connecticut, Massachusetts, Wisconsin, and New Jersey. *The pollution control market is responding to the increasing demand, making it feasible for companies to meet tight Hg limits.*" CAMR RTC Document at 9-76 (emphasis added).

Thus, there was little question that at such time the electric utility industry would need ACI to control Hg emissions under CAMR, the necessary supply would be available. As discussed above, there was an established supply chain in contrast to the state of the supply chain for low-GHG hydrogen, which is virtually nonexistent. Whereas CAMR merely required affected facilities to incorporate post-combustion pollution control equipment, the cofiring of low-GHG hydrogen changes the basic combustion process itself and effectively redefines the source and, for the first time, puts electric utilities in the position of having to produce their own fuel. Unlike ACI, which would have been a primary use case for the utility industry, significant competition across multiple industry sectors can be expected for whatever low-GHG hydrogen is produced.[77]

The current state of CCS is also easily distinguishable from that of ACI circa 2005. As discussed above, myriad challenges exist with CCS, including site- and region-specific geologic suitability, insufficient pipeline infrastructure, lack of a federal pipeline permitting regime, insufficient eminent domain authority, long-term liability, and public acceptance. EPA's final rule should align the time requirements with industry workstreams to bring low-GHG hydrogen and CCS to commercial availability.

D. Forcing Undemonstrated Technology on the Electric Utility Industry Is Unnecessary

Not only is it unlawful for EPA to establish standards now based on technologies that have yet to be adequately demonstrated, but it is also unnecessary. The Act provides

[77] See, for example, U.S. Department of Energy, Pathways to Commercial Liftoff: Clean Hydrogen, March 2023, p. 39.

that EPA “shall, at least every 8 years, review and, if appropriate, revise” the section 111(b) standards. 42 U.S.C. § 7411(b)(1)(B). Although EPA must undertake this review “at least every 8 years,” there is nothing in the statute that prohibits the agency from revising the standards before the passage of eight years if technology has advanced to the point that an earlier review and revision are appropriate. Therefore, rather than trying to predict the future by establishing standards based on carbon emission reduction technologies that do not meet the statutory standards, at such time hydrogen cofiring and CCS are adequately demonstrated technologies, EPA should apply the statutory factors to determine if they are the best system of emission reduction and, if so, modify the standards to reflect this.

XIII. State Plan Development and the Approval of Requirements for Existing Sources

A. Timing of State Plan Development and Submission

EPA has allocated insufficient time for state plan approval given the level of commitments necessary and the need for regulatory approval of compliance projects from state public utility commissions. EPA proposes that state plans be due 24 months after a rule is finalized, which would be April 2026 assuming the rule is finalized in April 2024. However, given Duke Energy’s experience in working with state agencies to begin developing compliance plans under rules such as the Clean Power Plan and the Affordable Clean Energy rule, it may require as much as 36 months for companies to analyze EPA’s final rule, complete complex system analysis, make the appropriate choices, get those approved by the appropriate regulatory commissions, and then be able to commit to individual projects for the state compliance plan. From that point, the state should have an additional 12 months to finalize its state plans and conduct the necessary community outreach before the plans can be fully considered as complete. In addition, some states have more extensive review processes required by state regulation. As was previously mentioned in Footnote 13, the Commonwealth of Kentucky earlier this year passed Senate Bill 4, which prohibits the Public Service Commission from approving a request by a utility to retire a coal unit unless the utility demonstrates that the retirement will not have a negative impact on the reliability or the resilience of the electric grid or the affordability of the customer’s electric rates. EPA’s allotment of one year (until 2027 under the above scenario) is also insufficient given the 2030 compliance deadlines (for example, for coal units) in EPA’s proposal. Companies would be at risk of needing to initiate compliance projects before EPA plan approval.

Duke Energy urges EPA to extend its proposed state plan submittal and EPA approval deadlines, and also extend its 2030 compliance deadlines.

B. Duke Energy Supports a Dual Track/Bifurcated Approval Process in the State Plans to Maintain Flexibility and Adapt to Changing Conditions

The EPA requested comment on a potential bifurcated approach to state plan submissions for affected steam-generating units and affected combustion turbine EGUs. In contrast to the proposed compliance deadline (2030) for steam-generating units, the EPA is proposing later compliance deadlines for combustion turbine EGUs in the CCS subcategory and combustion turbine EGUs in the hydrogen cofired subcategory of Jan. 1, 2035, and Jan. 1, 2032 (with a second phase commencing on Jan. 1, 2038), respectively.

Despite the longer period between the anticipated date of a final rule and the proposed compliance deadlines for affected combustion turbine EGUs, EPA proposed that state plan submissions containing standards of performance and other applicable requirements for these units would still be due 24 months after promulgation. EPA's rationale for this was that it believes that states; owners and operators of affected EGUs; RTOs, ISOs, or other balancing authorities; and the public may benefit from considering the control strategies for all affected EGUs under these emission guidelines on the same timeline. However, the EPA also acknowledged that the compliance time frames for combustion turbine EGUs are likely to be longer than those for steam-generating units under these emission guidelines due to, inter alia, the need to phase installation of CCS across the power sector and the continued ramp-up in production and transmission capacity for low-GHG hydrogen. EPA therefore requested comment on an approach where states would submit two different plans on different timelines: a state plan addressing affected steam-generating units due 24 months after promulgation of a final rule and a second state plan addressing affected combustion turbine EGUs due 36 months after promulgation of a final rule.[78]

Duke Energy agrees that in the final rule, EPA should give states the option to adopt this staggered approach for combustion turbine EGUs in the CCS and the hydrogen cofired subcategories, but EPA should extend the state plan submission deadline for these units to 48 months after promulgation of a final rule. First, the deadline for implementing 30% hydrogen fuel blending is Jan. 1, 2032, which is 24 months later than the Jan. 1, 2030, compliance deadline for affected steam-generating units. In the case of the CCS subcategory, the Jan. 1, 2035, compliance deadline is even later. However, EPA's proposal would give states only an additional 12 months for combustion turbine EGUs.

Based on its experience working with its states on the Affordable Clean Energy rule, Duke Energy believes that EPA should give states a full 24 months of additional time under a bifurcated approach. This approach could be a strong benefit to some states and allow them to plan their workload over that longer period of time. Given the scope of this rule, the time and resources needed for analysis and development of plans, development and approval of any state rules, approvals from other regulatory agencies such as public service commissions, and community interaction will be extensive. Many states are already feeling the strain of limited resources. Moreover, as EPA states in the

[78] 88 Fed. Reg. at 33,403.

preamble, hydrogen cofiring and CCS are longer lead projects that will depend heavily on infrastructure that extends beyond the typical site such as green hydrogen production and transport, and sequestration and storage. An additional 24 months for state plan development will also be very valuable for sources to develop their plans and secure commitments from the various providers before it would need to start making commitments under the state plan that are state and federally enforceable.

XIV. Setting of Individual Existing Unit Standards and Consideration of Remaining Useful Life and Other Factors (RULOF) by the States

A. States Need Broad Discretion for Applying RULOF and Other Factors in Their State Plans to Consider Facility-Specific Situations

CAA section 111(d)(1) expressly requires the EPA to permit states to consider RULOF and other factors when applying a standard of performance to a particular affected existing EGU. However, in its proposal, EPA states that any costs associated with any BSER for affected EGUs that the EPA determines are reasonable under these emission guidelines or are not fundamentally different from reasonable costs cannot be a basis for invoking RULOF. On the other hand, EPA further explains that costs that constitute outliers, e.g., that are greater than the 95th percentile of costs on a fleetwide basis (assuming a normal distribution) or that are the same as costs the EPA has determined are unreasonable elsewhere under the emission guidelines, would likely represent a valid demonstration of a fundamental difference and could be the basis of invoking RULOF.

In principle, Duke Energy agrees with this basic approach but has concerns. While EPA used the 95th percentile as an example, this should not be seen as an absolute. Given the diversity of EGUs and their specific situations, the 95th percentile may not be an appropriate threshold. When reviewing a variety of facilities, it is possible that for individual units, the costs could be three, five or even 10 times the cost threshold that EPA deems “reasonable” and be at 75th to 90th percentile. These situations could be related to whether hydrogen infrastructure/supply and/or CO_2 storage/infrastructure is available and the cost for a specific facility. Situations such as those could very well represent a valid demonstration of a fundamental difference and could be the basis of invoking RULOF. States need the flexibility and broad discretion to determine how to incorporate RULOF into their state plans and consider these facility-specific situations. It is important for EPA to better communicate this discretion in the final rule, which will assist states in the development of their plans.

B. States Need the Flexibility to Account for the Variability in Unit Operation When Setting Performance Standards

In Section XII (D) of the proposal, EPA discusses the process for “Establishing Standards of Performance” in state plans. Specifically, Section XII (D)(1)(b) describes the EPA’s proposed methodology for establishing presumptively approvable standards of performance for existing coal-fired steam-generating units.[79,80] It proposes a presumptively approvable standard of performance reflect a BSER of routine operation and maintenance for the Imminent-term and Near-term subcategories to not exceed the baseline emission performance of the affected EGU. EPA further states that while it believes that the baseline performance level adequately accounts for variability in annual emission rate, the EPA is also soliciting comment on a methodology for a presumptive standard above the baseline emission performance. For the Imminent-term coal-fired subcategory, the EPA is soliciting comment on a presumptive standard that is defined by 0 to 2 standard deviations in annual emission rate (using the previous five-year period of data) above the baseline emission performance, or that is 0% to 10% above the baseline emission rate. Duke Energy supports giving states the flexibility to specify emissions rates based on 2 standard deviations in annual emission rate (using the five-year period of data) above the baseline emission rate, or a bandwidth of up to 10% above the baseline emission rate.

A key concept that must be considered by the states when evaluating BSER and setting emissions standards is that an EGU's CO_2 emission rate is impacted by how the unit is dispatched. As industry has articulated in other rulemakings, including the Clean Power Plan and the Affordable Clean Energy rule, EGUs reach their best efficiency when they are operated at a level close to full load. On the contrary, if a unit is dispatched at a lower rate, its emission rate will increase. These are dynamics governed by the laws of thermodynamics and beyond the control of operators.

When considering a unit's longer-term average emission rate, factoring in more frequent cycling between high and low load as well as more frequent startups and shutdowns (which are inevitable with higher volumes of renewable resources), that unit's average emission rate will increase even for a unit that it is being effectively maintained and operated. While the average emission rate may increase on a given unit, its total tons of CO_2 emitted overall will still decrease when cycling because it is being operated less frequently. As energy markets continue to evolve, many coal-fired EGUs over the past few years have shifted from baseload operation to cycling operation or peaking operation. In proposing the "Near Term" subcategory, EPA is creating an entire class of units that will be forced into more frequent cycling and more frequent startups because of the 20% capacity factor restriction. Because of these factors, some units will see increases in their average emission rate. States are better equipped to address these circumstances in their state plans than EPA and should be given wide latitude to do so.

C. Establishing Baseline Emission Performance for Presumptive Standards Should Recognize Historical Natural Gas Cofiring by Coal-Fired Units

When establishing baseline emission performance standards, EPA and states should account for historical natural gas cofiring for all subcategories of coal-fired steam-generating units. EPA states that its proposed methodology for calculating standards of

[79] Section XII (D)(1)(b)(iii) Imminent-Term Coal-Fired Steam Generating Units, 88 Fed. Reg. at 33,377.

[80] Section XII (D)(1)(b)(iv) Near-Term Coal-Fired Steam Generating Units, 88 Fed. Reg. at 33,378.

performance entails establishing a baseline of CO_2 emissions and corresponding electricity generation for an affected EGU and then applying the degree of emission limitation achievable through the application of the BSER. The methodology for establishing baseline emission performance for an affected EGU is identical in each of the subcategories but will result in a value that is unique to each affected EGU.[81] While EPA states that the process is identical for all of the subcategories, there are inconsistences that need to be corrected. Specifically, EPA proposes the following for states when setting a standard of performance for medium-term coal-fired steam-generating units:

"For medium-term coal-fired steam generating units that have an amount of cofiring that is reflected in the baseline operation, the EPA is proposing that States account for such preexisting cofiring in adjusting the degree of emission limitation. If, for example, an EGU co-fires natural gas at a level of 10 percent of the total annual heat input during the applicable 8-quarter baseline period, the corresponding degree of emission limitation would be adjusted to 12 percent (i.e., an additional 30 percent of natural gas by heat input) to reflect the preexisting level of natural gas cofiring. This results in a standard of performance based on the degree of emission limitation achieving an additional 30 percent cofiring beyond the 10 percent that is accounted for in the baseline. The EPA believes this approach is a more straightforward mathematical adjustment than adjusting the baseline to appropriately reflect a preexisting level of cofiring."[82]

Duke Energy supports accounting for natural gas cofiring in the baseline, but it observes that EPA includes this provision only in the section related to medium-term units. On the contrary, this process is just as applicable to the other subcategories. For example, an existing coal-fired unit that is currently cofiring some degree of natural gas could elect to install CCS technology. In this instance it is necessary to back out the impact of natural gas cofiring when determining the unit's emission baseline. The process may require states to utilize different computational methods; however, they should be given that option and operators can be expected to provide any additional information necessary to perform this analysis. To not do so would be inconsistent and impose a more stringent standard of performance on non-medium-term units that have cofired in the past.

XV. Compliance Flexibilities

As stated previously, EPA's proposal is very ambitious, and its timing is extremely accelerated. It would mandate large amounts of new equipment and related infrastructure be designed, permitted, constructed and placed in service in a very short time frame. An averaging program that provides compliance flexibility for existing units could provide real and significant benefits.

[81] Section XII (D)(1)(a), 88 Fed. Reg. at 33,375.

[82] Section XII (D)(1)(b)(ii), 88 Fed. Reg. at 33,377.

However, it should be noted that, even if fully implemented, compliance flexibilities like emissions averaging will not be sufficient to overcome the proposal's shortcomings, particularly for existing units. Emissions averaging might, for example, be able to smooth out the operation of certain units. However, if the basic infrastructure for reliable hydrogen and/or natural gas supply is simply not available, no amount of compliance flexibility will help.

A. Duke Energy Supports the Use of Averaging and Trading as a General Matter

The preamble states that "EPA is proposing to allow states to incorporate averaging and emissions trading into their State Implementation Plans, provided that these states ensure that use of these compliance flexibilities will result in a level of emission performance by the affected EGUs that is equivalent to each source individually achieving its standard of performance."[83]

Duke Energy supports these types of compliance flexibilities because they have historically reduced the cost of compliance while delivering the required environmental benefits. However, we observe that an emissions averaging program is probably simpler for a state to develop and implement than an emissions allowance trading program, and thus it is our preferred approach. Nonetheless, we would still support a state's decision to implement an emissions trading program. Duke Energy urges EPA to take steps to make these provisions as easy to implement as possible and strive to minimize restrictions. Properly constructed, these programs can easily incorporate different subcategories and fuel types and evolve over time to accommodate changing standards. The benefits of these programs will include the more efficient deployment of capital and other resources while maintaining strong compliance. In principle, if applied over time, they can also allow sources to better stage the deployment of technology.

B. Compliance Flexibility Can Be Executed While Maintaining the Stringency of BSER

While we have concerns with the stringency and timing of the proposed standards of performance, Duke Energy agrees with EPA that averaging and trading programs, when appropriately designed and applied, can maintain BSER. In the proposal, EPA notes that "these flexibilities, trading and averaging, would be used to comply with the standards of performance, rather than establish the standards of performance in the first place."[84] EPA identified multiple instances where it previously authorized these programs as compliance methods in other emissions guidelines.[85] In each case it was able to maintain the integrity of the emissions reductions. For example, in the Clean Air Mercury Rule (CAMR), EPA finalized a two-phase cap and trade program under Section 111(d), which is the same program at the heart of this current proposal. Under CAMR, EPA stated that its trading program was considered BSER for mercury reductions.

[83] Section XII (E), 88 Fed. Reg. at 33,392.

[84] 88 Fed. Reg. at 33,392, footnote 659.

[85] 88 Fed. Reg. at 33,392, footnote 658.

Ultimately the court vacated CAMR on other grounds, so it took no action that questioned the viability of EPA's cap-and-trade program under 111(d). In a second example, EPA cited the Title IV NOx averaging plan, which had a demonstration process to show that units as part of an averaging plan were operated collectively at least as stringently as the units operated separately. It allowed companies to optimize investments by deploying better control technology on some units to over-comply and in turn average down other units' emissions.

C. Duke Energy Recommends that EPA Develop a Model Emissions Averaging Rule for States to Adopt by Reference in Their State Plans

When regulating existing sources under Section 111(d), the states develop and submit a state plan to EPA for their approval. As discussed above, EPA should delegate to the states the option of developing averaging and trading programs in their state plan. This will require each state to expend resources to develop their own averaging plan, which may differ from state to state. EPA would then have to approve each individual plan. EPA could greatly facilitate and simplify this process by establishing a model rule for emissions averaging that the individual states could adopt at their discretion. States would still be free to develop their own program, but a model rule would give states certainty knowing that their plans were approvable, plus a model rule would promote consistency among the states.

EPA should create a model averaging plan rule based on the very successful Title IV NOx averaging program, which was implemented under the 1990 CAAAs.[86] Title IV plans were able to successfully demonstrate that the level of emission performance by the affected EGUs in a plan was equivalent to each source individually achieving its standard of performance. This template could very easily be converted to regulating CO_2.[87] Furthermore, EPA has a proven track record of administering averaging plans under Title IV and could easily administer a similar program for EGU CO_2 emissions. Below are some aspects of such a model rule for state averaging plans.

- Averaging plans under this model rule would use the same calculational formulas as Title IV NOx averaging plans, except that CO_2 is substituted for NOx.
- Emissions limits would be those determined by the states using the process outlined by EPA and appropriately applying RULOF.
- All units in a plan would fall under a common designated representative as identified for the Acid Rain, CSAPR and other programs.
- Averaging plans would be established for a multiyear period but could be revised as frequently as annually depending upon a company's needs.
- Multiple types of existing units (coal, gas-fired EGUs and combined cycle) can easily be included in the same averaging plan.

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[86] 40 CFR Part 76 "Acid Rain Nitrogen Oxides Emission Reduction Program."

[87] Title IV NOx Averaging Plan Forms.

- Ensuring BSER is met is purely a calculation exercise of comparing a plan's actual performance against the required performance using the state-approved emission limits.

D. EPA Should Permit Averaging Plans Under a Model Rule to Be Constructed Across State Borders

A benefit of instituting an EPA-developed model averaging plan rule is that the provisions will be consistent and compatible among the participating states. As a result, the next logical step would be for EPA to permit the development of state averaging plans that extend across state lines for states that adopt the model rule. Such plans would be under the responsibility of a single Designated Representative as they are with the current Title IV plans. The increased flexibility from interstate averaging will allow sources to realize much of the benefits of a cap-and-trade program but with a far simpler burden. Duke Energy strongly urges EPA to take this step because of the increased compliance flexibility it would provide.

E. States Should Have the Option of Including Emission Trading Programs in Their State Plans

Duke Energy supports EPA giving states the latitude to develop and implement their own emission allowance programs as another form of compliance flexibility. The states would need to invest a significant amount of effort to develop the program elements and supporting regulations, plus conduct the necessary stakeholder engagement. Some states may not have the resources and experience to develop such programs. EPA does have extensive experience managing cap-and-trade programs and would be an excellent resource to administer the mechanics of a CO_2 trading program. Similar to Duke Energy's recommendation for emissions averaging, EPA should develop a model trading rule that could be adopted by multiple states. This would simplify the process and facilitate EPA's approval of state plans. A model rule also allows for developing one large trading market with a common structure and allowance currency. Without this sort of common program, the process will fragment into a patchwork of small individual markets and lose the efficiencies of a wider trading market.

Even with an EPA model rule and support for a trading program, each state would still need to make important policy and other decisions. This may prove challenging given the magnitude of the rule's impacts and the limited time EPA has made available for state plan development.

EPA's proposed BSER is based on emission rates while emission trading programs typically set tonnage caps and allocate emission allowances equal to the cap. These are two fundamentally different approaches. A rate-based approach sets an emissions performance standard on the amount of material input[88] or product output,[89] but it does

[88] A common example for EGUs is heat input based on pounds of emission per million Btus of heat input.

[89] A common example of EGUs is energy output based on pounds of emissions per MW-hr generated.

not regulate the total emissions output of an individual source. Cap-and-trade programs, by comparison, collectively regulate the total emissions output of a group of sources. To determine the size of a state's emissions budget, it is necessary to project the level of activity (e.g., heat input and/or energy output) for all of the sources in all of the years covered by the cap. States would need to update their projections periodically and update their cap.

Once a state determines the level of a cap, it must then determine how to allocate the actual emissions specifically over time. States also need to decide how to include new sources in the program for purposes of receiving allowance allocations. States also need to determine how retiring units are to be handled when they stop receiving allocations, etc. Duke Energy requests that EPA refrain from restrictions on the banking of allowances and trading between different states. Finally, an annual true-up process with retirement of consumed allowances will be required.

F. EPA Should Allow Generating Units to Earn Credit when Making Reductions Beyond the Standards and for Taking Early Actions

When considering ways to ameliorate its highly ambitious proposal, EPA should also consider giving sources opportunities to earn credit for reductions made ahead of the compliance date and for making reductions beyond the applicable standards. As previously stated, extending opportunities for compliance flexibilities will not solve the fundamental problem with this proposal's aggressive targets and timing. Under this proposal, as discussed above in Section III, companies would have to install massive amounts of infrastructure, which cannot be accomplished on the schedule proposed. While delaying different provisions of this rule could help smooth the transition overall, some sources may be able to take early actions to reduce their CO_2 emissions. As an example, a source could begin to cofire before its due date and/or cofire at a level higher than the standard of performance. Companies can and should be given the opportunity to take these measures and in exchange have more flexibility to phase in actions at other facilities. This makes sense given that this proposal's concerns with CO_2 are long term and global in nature as opposed to pollutants with short-term health effects such as those regulated under the NAAQS program.

There is precedent where EPA has taken similar measures in other programs. As an example, under the original NO_X SIP Call in 1998,[90] EPA created a pool of Early Reduction Credits that sources could earn by operating new controls prior to the compliance date. At that time, Selective Catalytic Reduction (SCR) was a new technology for NOx control with little domestic experience. Certain Duke Energy units were able to begin operating SCRs before the compliance date, earn ERCs, help stage the construction of equipment and very importantly gain experience in operating the new controls prior to the compliance date.

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[90] Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone (NOX SIP Call), 63 FR 57,356 (Oct. 27, 1998).

Duke Energy believes that EPA has the flexibility to create an expansive Early Reduction Credit program and achieve greater benefits by including new and existing units and as many subcategories as possible. New units could participate and earn ERCs provided they operate at an emissions rate lower than their performance standard. However, because new units are each individually subject to a performance standard, Duke Energy believes that they themselves could not utilize ERCs to demonstrate compliance. Any ERCs they generate could assist existing units in complying with their standard of performance. To address existing sources under the 111(d) program, states would be responsible for including ERC provisions in their rules. They would need to demonstrate through appropriate accounting that the program would be no less stringent than BSER. To aid and facilitate the process, as with emissions averaging, EPA should facilitate this process by developing model rule language, and a program in the Clean Air Markets Division business system to manage such a program. States would have the option of adopting and referencing the program in their state plans.

The computational process for determining ERCs is very straightforward. As an example, if a unit had an emission rate (performance standard) that equated to a 40% natural gas cofiring, that unit could decide to cofire at a 50% level and achieve an even lower emissions rate. The difference in emissions rates equating to the 40% and 50% cofiring would be multiplied by the level of activity (MW-hrs) and would calculate the number of tons of additional reductions below the performance standard. These tons would be converted into ERCs, and then would be used to partially offset an equal number of tons emitted by a different unit according to the following formula.

$$\text{Unit adjusted emission rate (lb. } CO_2\text{/MWh)} = \frac{\text{(tons } CO_2 \text{ emitted by unit – the number of ERCs used)}}{\text{(total equivalent MW-hrs generated)}}$$

Note – in this illustration, the total equivalent MW-hrs generated includes the useful mechanical work produced and/or co-generated steam.

Once generated, ERCs could be used in the current year or banked for use in a future year. They would be a marketable commodity that could be transferred or sold to other entities for their use. Given its experience with the Title IV NOx averaging program and the various cap-and-trade programs such as CSAPR, the CAMD business system has the structure that could be used to administer this type of ERC program including crediting ERCs for compliance demonstrations. It could be implemented even without needing to institute a full-fledged cap-and-trade program.

XVI. Conclusion

Duke Energy appreciates the opportunity to comment on the EPA's proposed rule under Section 111 of the CAA. The company looks forward to continuing to collaborate with the EPA on the clean energy future.