UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Technical Conference on Environmental Regulations and Electric Reliability, Wholesale Electricity Markets, and Energy Infrastructure	)))))))	Docket No. AD15-4-000

INITIAL STATEMENT AND COMMENTS OF JAY MORRISON ON BEHALF OF THE NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

On behalf of the National Rural Electric Cooperative Association ("NRECA"),[1] I am pleased to provide the following initial comments on the implications of compliance approaches to the Clean Power Plan proposed rule, issued by the Environmental Protection Agency ("EPA") on June 2, 2014.[2] NRECA believes that the Clean Power Plan (CPP) is well outside the EPA's legal authority under the Clean Air Act, and that the CPP should be withdrawn in its entirety. NRECA maintains that, at its core, EPA's proposal is illegal and imprudent.[3] We understand, however, that this is not FERC's proposal. Thus, for purposes of NRECA's participation in the Commission's February 19, 2015 Technical Conference and in this proceeding in general, we

[1] I currently serve as NRECA's Vice-President of Regulatory Affairs, where I oversee a staff of professionals representing NRECA and its members on matters relating to federal and state utility regulation, power supply and delivery. Since joining NRECA in 1998, I have worked extensively on issues relating to wholesale market design, reliability, power supply and delivery, industry restructuring, renewable energy, energy efficiency, distributed generation, and the smart grid.

[2] *Carbon Pollution Emission Guidelines for Existing Stationary Sources in the Electric Utility Generating Units category*, 79 Fed. Reg. 34,830 (June 18, 2014) (hereinafter the "Clean Power Plan" or "CPP"). A copy of NRECA's Comments to the CPP, as filed with the EPA on December 1, 2014 ("NRECA EPA Comments"), are included herein as **Attachment A**.

[3] In our EPA Comments (**Attachment A**), we explained that "EPA has significantly overstepped its statutory and regulatory authority by attempting to regulate, under the guise of a Section 111(d) $CO2$ standard, all generation, dispatch, and demand for electricity across the Nation," and argued that the rule will not withstand judicial review. NRECA EPA Comments at p. 1.

will work with FERC to identify specific, essential modifications that must be made to any final EPA guidance, which will mitigate the impacts of the CPP and help ensure that electric power remains reliable and affordable for America's consumers.

This Statement focuses primarily on the questions to be raised in the first panel ("Electric Reliability Considerations") of the February 19 Technical Conference. I will discuss generally how state, regional, and federal plans for compliance will affect grid operations, and will discuss various operational issues – particularly as pertaining to NRECA's members – that could arise under different compliance approaches. I will also discuss infrastructure and resource adequacy concerns that arise under the proposed CPP, which will inevitably need to be addressed in order to ensure system reliability in the long run.

FERC has a crucial role to play in ensuring that environmental regulation does not impair or impede grid reliability. Going forward, a more transparent process between EPA and FERC is needed to examine such reliability implications. NRECA commends FERC for conducting a national and three regional technical conferences concerning the CPP, but there remains a need for EPA to involve FERC's economic, legal and engineering expertise over what changes to the electricity grid are cost-effective and feasible in a reasonable time frame.

Given both the complexity of the electric generating sector and the vital importance of a reliable – and affordable – supply of electricity, NRECA urges the Commission to adopt a Policy Statement through which the Commission will provide guidance and advice to EPA, in advance of promulgation of any final carbon rules for existing power plants. The proposed CPP represents a considerable challenge to electric rates affordability and a conceivably overwhelming impact to reliability for the industry and especially rural electric cooperatives.

As explained in greater detail below, NRECA asks the Commission to advance, at a minimum, the following modifications to any final EPA guidance as a way to mitigate the potential negative impacts to grid operations, reliability, and affordability (Just and Reasonable Rates) as states and regions develop their compliance plans:

(1) EPA must eliminate the interim goal reduction requirements;

(2) EPA must adopt a dynamic (as opposed to static) reliability safety valve – That is, a safety valve that provides the States the *ongoing* flexibility they will need to ensure affordability and reliability; and

(3) EPA must provide flexibility to extend the year 2030 compliance deadline (e.g. to at least year 2035) as required to preserve reliability, and to prevent the stranding of assets or unreasonable rate increases.

One of the reasons NRECA believes EPA has exceeded the statutory authority of the Clean Air Act is due to its decision to rely on so-called "outside the fence" options to reduce greenhouse gas emissions, and that decision leads to a scheme that results in the reliability concerns that are the focus of FERC's technical conferences in this docket. EPA could resolve many of the issues by staying inside the fence line of coal-based power plants and focusing on heat-rate improvements at the plants.

Though not the focus of these comments, NRECA also believes it is important for FERC to help EPA to review and modify the models and assumptions that EPA has used to establish C02 reduction targets for each state. FERC's expertise in electric system operations should help EPA understand the great degree to which it has overestimated the ability of utilities to achieve 6% reductions in coal-plant heat rates, to achieve 70% utilization rates of all NGCC plants, to adopt environmental dispatch, and more. That expertise will also facilitate EPA's understanding for the need to reduce state targets to more reasonably and affordably achievable levels and thus help minimize impacts on reliability or the ability of the grid to deliver power at just and reasonable rates.

I. INTRODUCTION – THE 'RURAL' CHALLENGE: AFFORDABILITY AND RELIABILITY

NRECA is the national service organization for more than 900 not-for-profit rural electric utilities[4] and our members labor to provide affordable and reliable electric power to their often-disadvantaged customers. They do so in an environment of ever-increasing regulatory mandates, geographical constraints, and demographic challenges. While in many instances, the CPP may force a utility to choose between providing reliable service and potentially having to shed load, there is a third potential outcome. That third outcome is providing reliable service, but at a significantly higher – and possibly unjust and unreasonable – cost. It may be possible to "keep the lights on" from a physics and technical standpoint, but the economics and the ultimate cost to

[4] NRECA's members provide electric service to approximately 42 million consumers in 47 states or 12% of electric customers. All or portions of 2,500 of the nation's 3,141 counties are served by rural electric cooperatives. Collectively, cooperative service areas cover 75 percent of the United States landmass, and represent a very significant and unique segment of the energy industry. Cooperatives are incorporated as private entities in states in which they reside and have legal obligations to provide reliable electric service, at the lowest reasonable cost, to their customer members.

Sixty-five rural electric generating and transmission cooperatives ("G&Ts") generate and transmit power to 668 of the 838 distribution cooperatives in the United States. Rural electric G&Ts produce half of the generation these 668 distribution cooperatives need. At least 75% of this generation, or 28,475 megawatts (MW), comes from coal-fired units. These units are in aggregate newer and equipped with more pollution controls than the energy sector as a whole. Half of the coal-fired units serving rural electric G&Ts were constructed in compliance with Clean Air Act new source review, and nearly 80% are equipped with flue gas desulphurization units, or "scrubbers," to control sulfur dioxide emissions. More than 60% of the units have been retrofitted with state-of-the-art nitrogen oxides (NOx) controls, while practically all of the units use advanced, low-NOx burner technologies.

the consumer in many cases will be prohibitive. The choice for many may be between paying an electric bill or paying the mortgage.

As proposed, the CPP exacerbates urban-rural inequalities and will disproportionately affect NRECA's member utilities, the majority of which serve the "persistent poverty" counties in the United States. Electric cooperatives utilities are particularly impacted by the proposed CPP because of their unique circumstances:

- In 2012, 70% of the co-op generated kilowatt hours came from coal.
- Nearly 70% of the co-op-owned coal generation was built from 1975 to 1987 during the Oil Embargo and Fuel Use Act years when Congress essentially banned the use of natural gas for electricity.
- These coal units still have significant remaining useful life. While the best available control technology for pollution reduction was installed when these units were built, co-ops also have spent billions of dollars on pollution control upgrades over the course of the last several years to meet current EPA regulations. In some cases, the cost of these upgrades exceeded the original cost of the power plant. As a result, co-ops have outstanding loans on many of these facilities and must dispatch these units to generate adequate revenue in order to repay the loans.
- Most cooperative utilities are small and do not have a diversified generation portfolio. Co-ops owning one unit, only part of a unit, or only coal generation do not have the ability to dispatch other lower-emitting units in order to meet a standard.
- Cooperative utilities are not-for-profit entities and do not have financial flexibility – That is, all costs are passed on to co-op consumer-owners, through their retail electricity bills.
- If cooperative-owned coal units are forced to shut down, the co-op's consumer-owners will still have to bear the costs of repaying the outstanding debt, while incurring additional cost for replacement power from the market (if available), or the cost of new generation.

Electricity is not a luxury good reserved only for wealthy individuals and prosperous counties, but an essential precondition for fulfilling basic human needs. It is vital for business and a critical element of modern residential life. In fact, for isolated rural residents, reliable electricity service can be a matter of life and death.

II. PRESERVATION OF RELIABILITY

FERC's jurisdiction over the electrical bulk power system means that it has a crucial role to play in ensuring that environmental regulation does not negatively impact grid reliability. The industry as a whole, and EPA in particular, needs to better understand the risks and issues facing the power grid in the future. The sufficiency of resource adequacy continues to be clouded by uncertainties arising from changing environmental regulation. The margin of surplus generation is narrower and more constrained than ever before.

The need for careful analysis and coordination among FERC and EPA is disturbingly apparent. Without a doubt, the CPP will trigger higher electricity prices and reliability issues for many consumers. Despite FERC's unique and well-established role in maintaining grid affordability and reliability, EPA has not taken advantage of FERC's expertise up to this point. As recognized by EPA, the CPP's proposed "environmental dispatch" must be implemented in manner that preserves reliability.[5] Yet EPA has failed to address how exactly it will require or enforce such "environmental dispatch" in light of the fact that FERC has primary (and exclusive) jurisdiction over wholesale rates, market rules, and enforcement of reliability standards. FERC has never implemented an environmental dispatch under the FPA or its regulations. FERC has ensured that variable renewable generation – largely wind – can participate effectively in the

[5] Environmental Protection Agency, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Proposed Rule, 79 Fed. Reg. 34,829, 34,899 (June 18, 2014) ("Many stakeholders raised concerns that this regulation could affect the reliability of the electric power system. The EPA agrees that reliability must be maintained and in designing this proposed rulemaking has paid careful attention to this issue.").

wholesale markets without undue discrimination.[6] But it has not ever required a generation dispatch preference for resources based on their emissions characteristics, or given a preference to certain types of generation resources for purposes of setting wholesale power sales rates or regulating transmission service.

A. FERC Should Recommend Elimination of EPA's Interim Compliance Goals

Individual States as well as regional transmission authorities have raised significant concerns over EPA's interim compliance goals for CO2 reductions that states must reach by year 2020, and final goals that states must reach by year 2030.[7] The interim goals undermine state authority to establish their own compliance plans, are unrealistic, would create undue costs for consumers, and would undermine the reliability of electric service. FERC should urge EPA to eliminate its proposed interim goals in the final guidance.

NRECA believes that the interim goals are inconsistent with the cooperative federalism Congress intended in Section 111(d) of the Clean Air Act ("CAA"). Congress gave EPA the authority only to determine the "Best System of Emissions Reductions (BSER)." It provided states the authority to determine the level of emissions reductions they can achieve using the BSER in light of a host of local circumstances, including the remaining useful life of the power plants in the state and the means by which they will pursue those emissions reductions. The

---

[6] *See e.g.*, Integration of Variable Energy Resources, 77 Fed. Reg. 41,482 (FERC 2012).

[7] The Clean Power Plan requires states, on average, to reduce their power-plant CO2 emissions 30% below 2005 levels by 2030. Each state (except Vermont) has an EPA-imposed emission performance standard, calibrated in lbs. CO2/MWh. The standards translate into statewide CO2 reduction targets. States must meet interim targets in 2020-2029 and final targets in 2030. For each state, compliance costs, electricity price impacts, and economic losses depend chiefly on how much the state relies on coal for electric generation and how much idle natural gas, nuclear, and renewable capacity is available to meet demand as coal generation is reduced or eliminated.

stringent emissions reductions EPA proposes and the tight schedules imposed to achieve those reductions deprive states of the statutory flexibility and authority Congress intended. For FERC, this will translate into implications for grid reliability. Many states cannot realistically achieve the levels of short-term emissions reductions EPA proposes. In many instances, as much as 80% of the state's total emission reduction has to be achieved by the year 2020 interim goals.

NRECA also maintains that EPA drastically underestimates the time it will take states to develop effective State Implementation Plans ("SIPs"). EPA gives states only one year to develop a SIP, two years if they are working to develop a regional SIP, and case by case, one additional year if the state can demonstrate it needs the time and it is making progress. In most cases, states will require legislation to authorize a SIP that addresses the broad range of industry activities covered by the CPP, including coal plant efficiencies, dispatch of natural gas generation, expansion of renewable generation, and expansion of state energy efficiency programs. Because many state legislatures meet for limited time periods during the year, and some legislatures do not meet every year, it may be impossible for many states to meet even the three year deadline for adopting a SIP. Most stakeholders agree that the CPP can be implemented at much lower cost on a regional basis. The fact is, however, it will take far more than three years for states to negotiate and obtain needed approvals for complicated multi-state emissions programs.

Even if states can meet the deadlines for filing a SIP, it is unlikely to be approved and implemented with much, if any, time before the interim compliance deadline. In the best case, SIPs will not be filed until mid-2016 at the soonest and mid-2018 on the outside if states require the full three years. EPA then has one year to approve the SIP. Experience with other EPA regulatory programs indicates that state SIPs are unlikely to be approved within that timeframe.

Thus, states will not have an EPA-approved SIP until mid-2017 at the soonest and mid-2019 on the outside. Once the SIP has been approved, state regulatory agencies will need significant time to engage in the rulemakings required to implement the SIP. Like the EPA, most state agencies must propose regulations, permit comment, develop final rules taking the comments into account and provide regulated entities time to implement new regulatory requirements. Should implementation of the SIP require coordination of regulations among several state agencies within one state or in multiple states under a multi-state plan, that will require even more time before the regulations can be implemented and progress can begin on meeting the interim goals.

Assuming states adopt EPA's building block approach, infrastructure and program investments required to meet the interim goals cannot be completed in the time permitted by EPA. The CPP's first building block requires significant upgrades to coal plants to improve their heat rates. Those upgrades must be individually engineered to each plant, the equipment must be acquired from manufacturers at a time of high demand driven by the CPP, and if reliability is to be maintained, the plants must wait in queue for permission to go down for the necessary changes. The CPP's second and third building blocks require significant additional output from gas and renewable generators. Before that generation can reliably replace the generation from existing coal plants, it will require investments in new renewable and gas generation projects, upgrades to many existing gas plants and changes to their air permits to allow them to generate at the levels EPA anticipates.

The gas and renewable generation that exists today levels took decades to develop. FERC undoubtedly agrees that those levels cannot be dramatically increased within a year or two. Building new renewable generation within the interim compliance timeframe, for example, would be unlikely. It takes two to three years to secure financing and the necessary permits, and to contract for, design, and install the actual equipment. It takes 12 months of wind data collection before financing can be obtained for a mid-size wind project. Significant increases in gas and renewable generation will require large investments in transmission to deliver that generation to load and pipeline and storage infrastructure to deliver the additional gas. Indeed, Chairman LaFleur recently remarked on January 28, 2015 before attendees at a National Press Club Luncheon that FERC's review of natural gas infrastructure, transmission and evolving markets will underpin implementation of the CPP, despite drawing unparalleled pushback. She went on to note that "[p]ipelines are facing unprecedented opposition, from local and national groups, including environmental activists" and that "[w]e've got a situation here." While FERC approval for new gas pipelines can usually be attained within a year (but rarely sooner), gas pipeline construction generally takes 3-5 years. And that assumes no significant delays in the acquisition of rights-of-way, which is unusual today. On average, transmission lines require five to eight years from conception and design to construction and operation.

Likewise, energy efficiency programs required for building block 4 will not be able to achieve and sustain the proposed annual energy efficiency requirement within EPA's compliance deadline. As Chairman LaFleur also pointed out during her January 28 speech, implementing energy efficiency programs will require evaluation, planning, and regulatory authorizations and these programs typically take years to fully implement. The energy efficiency programs of the twelve best performing states have been in place for several decades, and with three exceptions, none have achieved close to the 1.5% annual energy efficiency requirement proposed by EPA, and only two states have been able to sustain that requirement.[8]

[8] *See* NRECA EPA Comments at p. 147.

The CPP's year 2030 deadline for compliance is less unrealistic than the year 2020 interim deadline, but it still may not allow States with higher reduction goals to achieve them without significant and premature coal-fired power plant shutdowns. Even then, with all of the statutory, regulatory, and practical changes needed to implement a set of requirements as sweeping as the proposal, all involved – States, public utility companies, and other entities subject to proposal requirements – face substantial challenges in meeting the ambitious goals of the CPP. Certainly, the reliability (not to mention the cost) implications are unmistakable, particularly for rural cooperative utilities: Requiring states to meet the interim goals by shutting down existing coal resources before alternative resources can be built would impose undue cost on consumers and undermine reliability.[9]

---

[9] ERCOT and SPP have both conducted reliability analyses of the CPP and concluded that the interim goals established in the CPP cannot be accomplished in the time frame the EPA has proposed. They both concluded that shutting down existing coal before alternative resources can be built would create instability on the transmission system and could lead to outages.

ERCOT estimates that the Proposed Rule will result in the retirement of 3,300 – 8,700 MW of coal generation capacity, and the addition of 5,500 – 7,100 MW of renewable capacity compared to the baseline by 2029. However, the modeled retirements and capacity additions result in a reserve margin 2 – 3% below the reserve margin in the baseline scenario towards the beginning of the interim compliance timeframe, between 2020 and 2022.

SPP's assessment showed that by 2020, SPP's reserve margin would fall to 4.7%, which is 8.9% below SPP's minimum reserve margin requirement. This would mean that 9 out of 14 of SPP's load-serving members would be deficient. Furthermore, SPP found that its anticipated reserve margin would fall to -4.0% in 2024, increasing the number of deficient load serving entities to 10. These anticipated reserve margins represent a generation capacity deficiency of approximately 4,600 MW in 2020 and 10,100 MW in 2024.

MISO's economic analysis of the CPP concluded that the interim goals would significantly increase costs to consumers. MISO estimates that application of the building blocks as described in EPA's proposal across MISO's region would cost $90 billion in net present value over the 20 year study period (2014 – 2033), or $60 per ton of CO2 emissions avoided from existing units. Application of alternative compliance strategies outside of the building blocks would cost $55 billion, or $38 per ton of CO2 emissions avoided from existing units.

For all of the above reasons, NRECA strongly urges FERC to advance in a policy statement that EPA *must* eliminate the interim goal reduction requirements, provide at least five years for individual states to develop implementation plans under Section 111(d), and provide states in multi-state plans with at least seven years to develop such plans. If the CPP is not withdrawn in its entirety – a position NRECA continues to advance – the above noted modifications will help mitigate the impacts of the CPP, but by no means fully alleviate our concerns.

B. <u>FERC Should Recommend EPA Adopt a Dynamic Reliability Safety Valve that Provides the States the Flexibility Needed to Ensure Reliability</u>

The inclusion of a reliability safety valve which can be used as a potential relief mechanism to adjust or postpone emission targets in certain situations is a necessary revision to the CPP. In the Mercury and Air Toxics Rule, EPA recognized that overly aggressive schedules for implementation could undermine the reliability of the electric utility sector. EPA wisely provided in that rule for a reliability safety valve under which utilities could seek an additional year in which to implement the rule without running the risk of an enforcement action. NRECA urges FERC to now advance a similar concept to EPA: It is critical that a safety valve provision be a component of any final emission guideline. More specifically, NRECA submits that any final rule should include a *dynamic* – as opposed to a simply *static* – reliability safety valve that provides states the flexibility they need to "keep the lights on" and to keep power affordable even as conditions change on the grid. And while including a dynamic reliability safety valve concept in any final emission guideline would theoretically function as a safety net, the concept will not fully mitigate the impacts of the CPP.

The CPP has an unprecedented scope and degree of complexity requiring sweeping changes to the nation's electric generating resources. For the first time in any clean air rule, EPA has gone "beyond the fence." The rule does not merely require upgrades to individual power plants or improvements in plant operations. As explained above, EPA has established its "Best System of Emissions Reduction" on which each state's emissions targets are set based on the EPA's assumptions as to the best resource mix for each state, including coal, natural gas, nuclear, and renewable energy and EPA's determination as to how much electric energy consumers should be permitted to use. To reach its targets, EPA looked in part at the generation resources it believed were available to each state in 2012, the level of additional renewable resources it believed each state could add based on the renewable energy targets established by at least some of the states in each region, and the level of energy efficiency that the most aggressive states intended to pursue.

Because of the breadth of the proposed guidance, states and electric generating units' ability to comply with the Proposed Rule depends on a broad range of conditions that are completely beyond their control. States' ability to reach the targets set by EPA, are dependent on the accuracy of EPA's evaluation of the availability of different resources in each state in 2012, and the continuing validity of those assumptions going forward. EPA's assumptions did not and could not take into account a number of common industry risks:

- A state implementation plan ("SIP") that relies heavily on efficiency improvements at existing coal plants could find compliance stymied by changes that undermine those efficiencies, such as new environmental requirements that impose parasitic loads on the plant, or changes in plant dispatch as a result of market rules that reduce the efficiency of the plant.

- A SIP that relies heavily on the completion of a new nuclear unit could find compliance stymied by changes in NRC regulations, changes in the availability of financing, changes in the market value of the new nuclear unit, or an accident that significantly delays completion of the nuclear plant.

- A gas, nuclear generator, or other low-emitting resource on which a SIP relies could suffer a severe breakdown that requires months or years to fix, forcing the state to rely more heavily on higher-emission resources in the meantime. This is what happened when the San Onofre Nuclear Generating Station suffered a major breakdown, and subsequently never reopened.

- A gas generator on which a SIP relies could lose access to gas needed to operate due to a major breakdown in the pipeline that serves it that could take months to fix, forcing the state to rely more heavily on higher-emission resources.

- Transmission congestion caused by damage to an element of the transmission system, changes in the locations of major generation and load on the transmission grid, or changing transmission loading patterns resulting from significant changes in dispatch of generation resources could force a non-state regulated owner of a gas generator, nuclear generator, or other low-emitting resource to reduce its input. States would be forced to rely more heavily on higher emitting resources until the congestion is relieved, which could take months or years.

- Increases in fuel prices, increases in fuel transportation costs, loss of a major customer, decreases in competing higher emitting fuel prices, or a range of other changes in wholesale market design and market outcomes could cause non-state regulated owners of gas, nuclear, or other low-emitting generators to shut down the generator. The state would be forced to rely more heavily on higher-emission resources until a new lower-emitting resource could be built. However, if the market fundamentals are not there to support the lower-emitting generator that shut down, they may not be there for a new resource.

- Market prices for power could drop to such a degree, or the uncertainty of cost recovery could rise to such a degree, that the financial community might be unwilling to provide financing for new low-emitting resources on which a SIP relies.

- A state with a mass-based SIP could experience significant economic growth and thus significant load growth. That state would be forced to dispatch more power from emitting resources to meet the new demand reliably.

- New plug loads that increase per capita energy demand, such as electric vehicles or new high-demand consumer electronics, could force states to dispatch more power from emitting resources in order to meet the new demand.

- The effect of energy efficiency and renewable energy on other resources is likely to change over time due to the physics of the system or the operation of the wholesale market. A SIP that relies heavily on displacing higher emitting resources with energy efficiency or renewable investments could find its compliance hindered if those higher emitting resources are not displaced as expected.

Compliance with the proposed rule cannot be achieved with one-time installations of discrete technological fixes to specific power plants. Certainly, a safety valve that provides more time for state plans to be drafted, approved, and implemented is necessary, but will not be adequate to preserve reliability. EPA needs to allow states to amend their implementation plans and their compliance goals dynamically as the system changes. Any final EPA rule that fails to include such a mechanism would result in *de facto* failed policy, requiring states to choose between compliance, unacceptably high power costs, and reliability.

C. Electric Cooperatives Have Real and Significant Concerns

The year 2020 interim deadline is a serious concern to a number of NRECA's members. Similarly, the current inflexibility built into the proposed CPP to extend the year 2030 compliance deadline is also unacceptable. A number of the resources of electric cooperative will be forced to shut down before adequate affordable alternatives can be found. NRECA is in the process of collecting specific data and examples from our member cooperatives on how the proposed CPP will cause reliability and affordability problems. We expect to submit our analysis and anecdotes as a supplement to this filing with the Commission within the next fourteen days. We believe the Commission will find the information tremendously useful in any guidance it provides to EPA.

III. MARKET AND INFRASTRUCTURE CONCERNS

NRECA also urges the Commission to use this opportunity to further examine whether the centralized markets appropriately value fuel diversity, fuel security, and long-term assets in a manner that will properly incent new investment and continued operation of existing plants. As part of its analysis of the CPP, the Commission should ensure that the market rules and design do not adversely impact investments in diverse resources through self-supply (owned resources and bilateral contracts) by load-serving entities. Replacing baseload capacity, forced into an early retirement as a result of the CPP, while managing an increasingly variable energy mix will be the primary challenge to electric reliability in the coming decades.[10] Self-supply provides the types of long-term investments that should be relied upon to create and continue fuel diversity and fuel security.[11]

NRECA continues to urge the Commission to address the drivers of potential coal and nuclear plant retirements in light of those fuels' superior performance (particularly during events such as the 2014 winter polar vortex), and assess the impact that the loss of some of these assets will face in light of the CPP. Like other market participants, many electric cooperatives are being compelled to evaluate, plan and contemplate the retirement of coal-fired generation. But early retirement (particularly unnecessarily early) is a costly and permanent action. Based on what is now known about the performance of coal units, it seems certain that even if the units currently slated (or considered) for retirement are replaced with natural gas generation capacity, removing these historically dependable units from the grid will compromise and threaten reliability, and increase the probability that gas delivery problem and price volatility will only get worse in the near term during peak load or other extreme weather events.

For electric rural cooperatives, low-cost, reliable electricity results, in part, from the ability to utilize a variety of readily available energy resources – coal, nuclear energy, natural gas, hydropower, and emerging renewable energy resources, such as wind, biomass and solar. Fuel diversity is the key to affordable and reliable electricity, and stable prices. That important

[10] Satisfying new demand from population and economic growth can also challenge reliability but EIA predicts that electricity demand will increase by less than 1 percent per year by 2040. EIA, Annual Energy Outlook 2014 (Early Release) at p. 14 (2014).

[11] *See* NRECA Post-Technical Conference Comments filed in Docket No. AD13-7-000 on January 8, 2014 at 8 (discussing the critical role of self-supplied generation in ensuring long-term resource adequacy).

fact is recognized in the Energy Policy Act of 2005,[12] which includes many provisions that promote long-term fuel diversity. A diverse fuel mix helps protect consumers, our economy and our national security from contingencies such as fuel shortages or disruptions, price fluctuations and changes in regulatory practices. A diverse fuel mix takes advantage of regional differences in fuel availability that have evolved over many decades.

The CPP effectively phases out the use of coal as a future generation resource in the United States. This is a dramatic shift and has significant implications for the diversity of the U.S. electricity generation portfolio, for electricity suppliers, and for their customers.

IV. CONCLUSION: CARRY OUR MESSAGE TO EPA

NRECA commends the Commission for taking the initiative to convene the technical conferences on EPA's proposed CPP, and to establish this docket to examine reliability issues, infrastructure concerns, and the various market implications. NRECA is asking the Commission to carry our message to EPA. EPA's decision to rely on so-called "outside the fence" options to reduce greenhouse gas emissions is objectionable, and one that has led to potential implications for electric reliability. NRECA believes the CPP is outside EPA's legal authority under the Clean Air Act, but we recognize that it is not FERC's proposal. Thus, we will continue to work with FERC to identify modifications which will mitigate the CPP's impacts. NRECA is concerned that EPA's implementation schedule is much too rapid. The proposed year 2020 interim deadline will be impossible for most, if not all states, to meet. Thus, elimination of the interim compliance deadline is essential. NRECA is also concerned that the CPP assumes fairly static conditions on the electric grid between the year 2012 baseline date and year 2030. That is not a realistic assumption. A dynamic reliability safety valve which allows each state's goal to

[12] Pub. L. No. 109-58, § 1284(e), 119 Stat. 594, 980 (2005).

change as system conditions change is another necessary and critical modification. The Commission and Commission staff understand the complexity of the electric grid and the challenges of rapid change. NRECA remains hopeful EPA will seek out and pay attention to FERC guidance as EPA finalizes its rule.

With multiple pressure points on electric rates in addition to Section 111(d), the cost to the consumer is going to increase. The question remains: What is just and reasonable, and ultimately affordable for the consumer? A dynamic reliability safety could be used to maintain reliable electric service, but at a just and reasonable cost to the consumer. NRECA urges this Commission to make sure EPA understands the cumulative impact of its regulations on the entire resource portfolio. EPA must make decisions to optimize the environmental value of their efforts in an achievable, realistic manner.

The implications of the CPP underscore need to protect a diverse fuel mix and to maintain the existing coal plant capacity as a baseload fuel, particularly in the near term. NRECA and its member-cooperatives recognize that the ability to maintain system reliability faces new challenges associated with not only with environmental regulation, but with a changing generation fuel mix in general. Reliability rests on a mix of baseload, intermediate and peaking generation using a variety of fuels and technologies; and as it stands, the CPP threatens that reliability.

Modifying the CPP -- apart from a general need for FERC to reform rules relative to both day-to-day operational issues and broader market issues -- is critical to well-functioning wholesale markets' ability to provide the portfolio of resources necessary to maintain reliable and affordable electricity. Addressing these issues is immeasurably important to rural electric cooperatives: Electricity costs and reliability issues have a disproportionate impact on rural communities, and an "all-of-the-above" electric energy fuel strategy – which includes providing for much more time than EPA allocates by imposing year 2020 as the interim compliance goal – is essential for NRECA member systems.

For the reasons discussed above, NRECA respectfully requests that the Commission consider my statement and comments set forth above, and provide the necessary input and recommendations to EPA.

Respectfully submitted,

/s/ Jay Morrison

Jay Morrison
Vice President, Regulatory Affairs
National Rural Electric Cooperative Association
4301 Wilson Boulevard
Arlington, VA 22203-1860
Jay.Morrison@nreca.coop

Dated: February 18, 2015

ATTACHMENT A

TO INITIAL STATEMENT AND COMMENTS OF

JAY MORRISON ON BEHALF OF NRECA

[Copy of NRECA's Comments to the CPP, as filed with the EPA on December 1]

The National Rural Electric
Cooperative Association

Comments on

Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units and Notice of Data Availability

Submitted Electronically to:

The Environmental Protection Agency

Air Docket

Attention Docket ID NO. EPA-HQ-OAR-2013-0602

December 1, 2014

Rae E. Cronmiller
Environmental Counsel
4301 Wilson Boulevard, EU 11-249
Arlington, VA. 22203-1860
(703) 907-5791 / rae.cronmiller@nreca.coop

National Rural Electric Cooperative Association
Comments on Proposed Carbon Pollution Emission Guidelines for Existing Sources

EXECUTIVE SUMMARY

Background

As part of its effort to reduce CO_2 emissions to address climate change concerns, EPA has proposed to adopt three rules under the authority of Section 111 of the Clean Air Act (CAA). Two of these rules address new sources, or sources that are considered new under the authority of Section 111(b). On January 8, 2014, EPA proposed new source performance standards for coal-fired and natural gas-fired plants, and on June 18, 2014, EPA proposed performance standards governing modified and reconstructed sources in the same category. NRECA submitted comments opposing most portions of each of these proposals.

On June 18, 2014, EPA also proposed "emission guidelines" for CO_2 emissions from existing sources under the supposed authority of Section 111(d), though they are "guidelines" in name only. In fact, because the proposed guidelines are binding regulations, they leave the States no leeway to exercise their assigned duties under the Act and no room to consider the source-specific factors the statute identifies for existing sources. However, the whole of this Proposed Rule is illegal, imprudent, and impossible to implement. EPA's aggressive approach to interpreting the statute, its complete inconsistency with its own longstanding regulations, and its misinformed statements and Pollyannaish judgments about the electricity sector and the emission reductions sources in that sector can actually achieve, place the rule beyond salvage. These comments explore these infirmities in detail and explain why EPA must withdraw this ill-advised proposal and start over.

What NRECA Seeks

Because the Proposed Rule is unlawful and unworkable as drafted, EPA should decline to finalize it in its present form. If, despite the plain prohibition that the CAA places on the regulation of coal-fired electric generating units (EGUs) under Section 111(d) following EPA's issuance of the Mercury and Air Toxics Standards, EPA insists on renewing its efforts to limit CO_2 emissions from existing fossil fuel-fired units, it must limit itself to issuing true *guidance* for the States, and that guidance must respect the limits of

EPA's lawful authority and the legal and practical demands and constraints existing units face. First, EPA's definition of BSER must be limited to those emissions improvements that can be achieved within the fence line of *each designated source*. Second, EPA's guidance to the States must be limited to recommending how the States may establish their own standards of performance and apply those standards *based on what can be achieved at each designated source,* taking into account the factors enumerated in both Section 111(d) and EPA's longstanding regulations implementing that section. Any final emission guideline must allow the States to adjust their overall emission reduction targets based on what is actually achievable at each existing source within the State. EPA's overly optimistic, blanket assumptions cannot serve as the foundation for a binding, statewide target. Third, EPA must adhere to the statute's command that the States be given maximum flexibility in determining how to achieve compliance with the emissions standards they develop.

Given both the complexity of the electric generating sector and the vital importance of a reliable supply of electricity for the Nation's security and the economic wellbeing and physical safety of its citizens, any final emission guideline *must* allow the States to respond dynamically to the wide range of sometimes unpredictable conditions that affect the Nation's generating resources. If a nuclear plant must close for safety reasons, if natural gas generation cannot be dispatched at predicted levels, if necessary infrastructure is unavailable or delayed, if renewable generation proves unable to be delivered because of transmission limitations, if economic growth exceeds expectations, or if reliability and safety requires additional dispatch of higher-emitting resources, States should not be forced to choose between compliance and leaving their citizens and businesses without heat or power. Nowhere does the Clean Air Act expect or authorize such heavy-handed treatment of state authorities.

Next, in any final emission guideline, EPA must take action to remedy the logistical impossibilities it has created. First, the timeframes EPA proposes are absurdly short, particularly given the complexity of the tasks EPA has assigned the States. Recognizing this complexity, EPA should give the States at least five years to develop a state implementation plan ("SIP") for a single State and seven years to develop a multi-state SIP, rather than the maximum of two and three years, respectively, that EPA has proposed. The

Agency should also provide an extra three years for developing any SIP upon a demonstration of reasonable progress toward development of a SIP. Second, EPA should allow the States to adopt compliance deadlines that are based on the remaining useful lives of each of the designated existing facilities. Third, given the extensive legal, regulatory, and physical changes that must occur first, EPA should give the States flexibility to extend the statewide compliance date to at least 2035 as necessary to achieve compliance with any emission reduction targets, and to adjust the compliance date for any individual unit even further based on its remaining useful life as determined by the State. Fourth, EPA must abandon the interim targets it has proposed, as it will be impossible for States to meet those.

Summary of NRECA's Specific Comments

1. **The Proposed Rule violates the CAA because the affected EGUs are already regulated under Sec. 112.**

The statutory language of Section 111(d) is a product of differing House and Senate versions that were never reconciled in conference. Instead, both were signed into law. Under the Senate version, unless a particular air pollutant emitted by existing sources was regulated by one of several other listed Clean Air Act provisions, existing sources emitting that pollutant could be regulated under Section 111(d). The House version, on the other hand, prohibits existing sources from being regulated under Section 111(d) if the existing sources are already regulated under Section 112.

For reasons explained in these comments, the House provision controls. Because coal-fired power plants came under Section 112 regulation in 2012 when EPA issued the Mercury and Air Toxics Standards, EPA cannot regulate them under Section 111(d).

2. **The Proposed Rule violates the CAA because there is no valid new performance standard in place under Sec. 111(b).**

Also, Section 111(d) requires EPA to issue a valid *new source performance standard* under Section 111(b) before issuing an existing source standard under Section 111(d). Based on flaws in the proposed NSPS and modified/reconstructed source standard, neither can be lawfully finalized. Therefore, EPA has not satisfied this prerequisite to issuance of the Section 111(d) rule.

3. The Proposed Rule violates the CAA because it defines BSER based on activities beyond the fence and outside the control of the affected EGUs.

Even if EPA had legal authority to issue a Section 111(d) standard for existing coal-fired power plants, its proposal violates the structure and text of the Clean Air Act. First, EPA has no statutory authority to define the “best system of emission reduction” in a way that goes beyond technological or operational improvements that can be made at an individual source. EPA has acknowledged this limitation in its longstanding regulations and has abided by it in its prior new and existing source rulemakings. By requiring utilities to employ “outside-the-fence-line” measures, such as re-dispatch to other types of generation, and by requiring consumers to reduce their demand for electricity, EPA has impermissibly attempted to regulate the whole of energy generation and demand. It has reached far beyond the specified source category and light years beyond its limited statutory authority.

4. **The Proposed Rule violates the CAA because its fixed state targets trample on states’ statutory right to set performance standards themselves.**

Regardless of the definition of BSER, EPA’s authority under Section 111(d) is limited to determining what systems of emission reduction have been adequately demonstrated. EPA has no authority to set standards of performance for existing sources except where a State has failed to do so. Rather, under the plain language of the statute and EPA’s longstanding regulations, the States establish their own standards of performance based on EPA’s determination of BSER. The States then apply their standards on a unit-by-unit basis after considering source-specific factors such as the remaining useful life of each source, the reasonableness of the associated costs, physical impossibility, and other factors suggesting that a more relaxed standard or a longer compliance period is appropriate for the source. In the Proposed Rule, EPA unlawfully sets fixed, binding emission limits for each of the States. In so doing, EPA violates Section 111(d).

5. **The Proposed Rule violates the CAA because it interferes with states' statutory and regulatory obligation to take into account each EGU's individual circumstances in establishing performance standards.**

By usurping the States' proper role of establishing standards of performance and determining individual source emission limits, EPA has created insurmountable problems for the electric sector, especially for the rural electric cooperatives that operate in that sector. The limited generation portfolios of many rural electric cooperatives, the heavy reliance of many cooperatives on coal-fired generation, and other practical realities limit cooperatives' ability to implement BSER as radically envisioned by EPA. These issues make EPA's lb./ MWH reduction goals for all four "building blocks" impractical for most utilities and especially for cooperatives.

Any final rule must recognize these problems. Accordingly, if EPA insists on setting binding statewide emission reduction goals, those lb./ MWH reduction goals must be adjusted upward to reflect the cooperatives' and others' limited ability to comply with BSER.

6. **The Proposed Rule violates the CAA and the APA because the emission reduction targets EPA has set are unattainable.**

Numerous policy and technical impediments make the Proposed Rule impossible to implement. First, the proposal impermissibly requires States to attempt to regulate dispatch decisions that lie outside their legal authority. The proposal ignores that dispatch decisions are controlled by utilities, regional transmission organizations and independent system operators whose boundaries are not contiguous with state borders, whose dispatch decisions may lie beyond state reach, and/or whose dispatch decisions may be subject to exclusive FERC jurisdiction

Moreover, each of the Building Blocks is based on faulty, inexpert assumptions that have no record basis. The EPA's proposed state emission limits are based on significant miscalculations concerning such critical issues as limitations on utility efficiency improvements, natural gas availability and deliverability, existing natural gas generation capacity, transmission infrastructure required for additional renewable generation, the role of nuclear power as compared to other low- or zero-carbon generation resources, and achievable reductions in electricity consumption. Separately and together, these flaws demonstrate the EPA's fundamental mistake in calculating firm state emission targets based on its evaluation of the Building Blocks rather than permitting states to develop their own performance standards based on their individual evaluation of each EGU's ability to implement a BSER at that individual plant.

7. The timeframe EPA proposes for development and implementation of SIPs as well as the interim and final compliance deadlines are unworkable.

Even if the rule were restructured as we urge in these comments, the rule would be unworkable on the timeframes that EPA has set for compliance. EPA proposes to require States to submit their implementation plans within one year of any final emission guideline. Though EPA has proposed to allow extensions of one year for States proposing to submit plans alone and two years for States proposing to submit plans as part of a regional group, even these timeframes are inadequate given the complexity of the rule and the tasks States must undertake to implement it. We therefore propose that EPA abandon the Proposed Rule's interim emission reduction targets, give States five years to submit a plan if acting alone and seven years if submitting as part of a multi-State group, and allow up to an additional three years for development of a plan upon a demonstration of reasonable progress toward developing a plan.

In addition, EPA should abandon its requirement of a definite, one-size-fits-all final compliance date. The final compliance date should instead be based on the end of the useful life of a facility as demonstrated in loan document filings on record with various loan institutions as of January 1, 2014. This unit-specific final compliance date would itself comply with the Clean Air Act's express requirement that remaining useful life of each facility be factored into state plans. It would also mitigate the overwhelming financial burden many cooperatives face in complying with the Proposed Rule. Finally, a staggered compliance date would allow for staggered retirement of facilities, which would ensure that the resources and services necessary to restructure the American energy industry—i.e., engineering, design and permitting, transmission and generation asset manufacturing, and construction and labor—will be available when needed at a reasonable cost. If EPA insists on its arbitrary final compliance date in violation of the

Act’s instruction that state plans be based on the remaining useful lives of existing facilities, then EPA must establish 2035 as the earliest date on which any standards of performance must be complied with.

TABLE OF CONTENTS

Page

INTRODUCTION

The National Rural Electric Cooperative Association (NRECA) has grave concerns with Environmental Protection Agency's (EPA's) proposal for Carbon Pollution Emission Guidelines for Existing Stationary Sources in the Electric Utility Generating Units category, 79 Fed. Reg. 34,830 (June 18, 2014) (hereinafter the "Proposed Rule").

In the Proposed Rule, EPA has significantly overstepped its statutory and regulatory authority by attempting to regulate, under the guise of a Section 111(d) CO_2 standard, all generation, dispatch, and demand for electricity across the Nation. The Proposed Rule is an unparalleled exercise in regulatory hubris and cannot possibly withstand judicial review. It is also likely to cause irreparable damage to the Nation's economy and its residents. Its flaws are myriad. We attempt to address as many of them as possible here, in hopes that EPA will reconsider this foolhardy endeavor and withdraw the Proposed Rule.

NRECA is well positioned to offer a practical, critical assessment of EPA's Proposed Rule and its likely impact on the nation's energy sector. NRECA is a national service organization representing the interests of cooperative electric utilities and the consumers they serve. Rural electric cooperatives labor to provide affordable electric power to their often-disadvantaged customers. They do so in an environment of ever-increasing environmental mandates, geographical constraints, and demographic challenges. NRECA members comprise more than 900 not-for-profit rural electric utilities that provide electric service to approximately 42 million consumers, or roughly 12% of the U.S. population, in 47 States. Of the nation's 3,128 counties, 2,500 are exclusively or partly served by rural electric cooperatives. The service areas of NRECA members cover 75% of the U.S. landmass.

Sixty-five rural electric generating and transmission cooperatives (G&Ts) generate and transmit power to 668 of the 838 distribution cooperatives in the United States. Rural electric G&Ts produce half of the generation these 668 distribution cooperatives need. At least 75% of this generation, or 28,475 megawatts (MW), comes from coal-fired units. These units are in aggregate newer and equipped with more pollution controls than the energy sector as a whole. Half of the coal-fired units serving rural electric G&Ts were constructed in compliance with Clean Air Act (CAA) new source review, and nearly 80% are equipped with flue gas desulphurization (FGD) units, or “scrubbers,” to control sulfur dioxide (SO_2) emissions. More than 60% of the units have been retrofitted with state-of-the-art nitrogen oxides (NO_x) controls such as Selective or Nonselective Catalytic Reduction (SCR or SNCR), while practically all of the units use advanced, low-NO_x burner technologies.

Rural electric cooperatives serve large, primarily residential, low-density geographic regions; costs of providing service are high, and revenues low. Data from the U.S. Energy Information Administration (EIA) show that rural electric cooperatives serve an average of 7.4 consumers per mile of line and collect annual revenue of approximately $15,000 per mile of line annually. In contrast, investor-owned utilities (IOUs) serve an average of 34 customers per mile of line and have annual revenues of approximately $75,500 per mile of line. Electric cooperatives have a significantly higher proportion of residential consumers than municipal and investor-owned electric utilities.[1] Due to this geographically-determined disparity in distribution costs and revenues, the residential electric rates of 63% of rural electric cooperative members are higher than those charged to the customers of nearby IOUs. These higher rates impede the economic recovery of rural communities and challenge their viability.

Low population density affects not only the cost of providing electricity, but also electricity demand, making rural Americans more vulnerable to rising electricity costs. Because population is more dispersed in America’s rural expanses, people tend not to live in tightly packed apartments, but in detached single unit homes that endure significant exposure to the elements. For these reasons, the average monthly electricity usage for households served by electric cooperatives is 1,128 kW a month, significantly higher than the IOU average of 829 kWh or even the municipal average of 971 kWh.[2] Moreover, because many rural residents do not have access to natural gas and depend on electricity and expensive propane and heating oil for warmth during cold months, electric cooperative members lack practical, affordable alternatives they can turn to when their electric rates rise. The economic reality of higher heating costs falls particularly hard on low-income families living in rural America’s manufactured and mobile housing. The

[1] Information taken from U.S. Department of Energy, Energy Information Administration EIA Form 861.
[2] 2012 weighted average data from EIA Form 861; of course there is wide variation geographically due to different weather patterns and availability of heating alternatives.

percentage of mobile homes as a share of housing stock in electric cooperative territories is more than double the U.S. average.[3] Electricity is not a luxury. It is vital for business and an essential element of modern residential life. For isolated rural residents, reliable electricity service can be a matter of life and death.

The Proposed Rule exacerbates urban-rural inequalities, placing a heavy burden on the rural electric consumers cooperatives serve. For example, the Rule requires that roughly half of the total reductions in greenhouse gases be achieved through implementing energy efficiency measures. Yet, the Rule fails to consider EPA's own analysis that energy efficiency measures undertaken in the residential sector are considerably less effective on a dollar-per- kWh -reduction basis than those undertaken in the industrial and commercial sectors.[4] The Proposed Rule's re-dispatch objectives neglect to acknowledge that many rural cooperatives have limited generation portfolios and little ability to draw from lower-emitting sources. NRECA has conducted a rigorous, in-depth analysis of how the EPA's proposed Clean Power Plan will impact cooperative members, using the Promod IV electricity market simulation model to determine the costs to comply with EPA state Option 1 emission targets. The results show that a number of cooperative members could see delivered electricity rate increases of over 40%. On average, cooperative members could see delivered electricity rates, inclusive of all demand-side efficiency costs, increase by 17% over the 2020 -2030 period. NRECA's analysis reflects the higher first year costs incurred by rural electric cooperatives and features both a 7% discount rate and a 15-year equipment life to reflect the relatively higher costs to rural electric cooperative members in achieving the EPA Option 1 energy efficiency targets.

[3] The percentage of mobile homes as a proportion of housing stock is 14.7% in cooperative territories. The national average is 6.5%. For electric cooperatives serving exclusively rural territories, the mobile home share is 17.1%. U.S. Census data with calculations provided by EASY Analytic Software, Inc.

[4] Billingsley, M.A., I. M. Hoffman, E. Stuart, S. R. Schiller, C.A. Goldman, K. LaCommare, *The Program Administrator Cost of Saved Energy for Utility Customer-Funded Energy Efficiency Programs*, Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division, March 2014, Figure ES-1, p. xii.

The Proposal wholly ignores the countervailing factors, including non-air quality health impacts, that EPA *must* consider when determining best systems of emission reduction, or BSER.[5] In proposing unrealistic, binding, state-wide targets, the Proposed Rule threatens to strand assets, sabotage reliability, and explode the cost of electricity for some in rural America. For reasons identified and discussed throughout these comments, this Proposed Rule would have an especially significant and detrimental impact on small entities as defined under the Small Business Regulatory Enforcement Fairness Act (SBREFA) and implementing regulations. Since 98% of rural electric cooperatives fall below the Small Business Administration threshold for small entities under SBREFA, the NRECA membership as a whole would face extraordinary challenges should this proposal be finalized as proposed. For this reason we urge EPA to form a Small Business Advocacy Review (SBAR) Panel as required in EPA's own SBREFA guidelines to identify and discuss options for lessening the proposal's impact on affected small entities.

At its core, EPA's proposal is illegal, imprudent, and unworkable. NRECA urges EPA to abandon its ill-conceived effort and withdraw this unlawful Proposed Rule.

ARGUMENT

I. EPA lacks statutory authority to promulgate the Proposed Rule.

EPA claims that Section 111(d) of the Clean Air Act authorizes it to promulgate the Proposed Rule. Indeed, Section 111(d) is the *only* statutory authority EPA invokes on behalf of the Proposed Rule. But under any reasonable construction, Section 111(d) expressly prohibits what EPA proposes.

A. The Proposed Rule is unlawful because source categories already regulated under Section 112 cannot be regulated under Section 111(d).

1. Section 111(d) expressly prohibits double-regulating source categories already regulated under Section 112.

EPA's attempt to reduce CO_2 emissions from existing coal-fired EGUs under Section 111(d) violates the plain language of that section. As recorded in the official United States Code, Section 111(d) prohibits EPA from regulating "any pollutant . . . from a source category which is regulated under Section

[5] See *Portland Cement Ass'n v. EPA,* 665 F.3d 177, 191 (D.C. Cir. 1973).

112."[6] The Supreme Court has expressly recognized this prohibition, stating definitively in *American Electric Power Co. v. Connecticut* that "EPA may not employ § [111](d) if existing stationary sources of the pollutant in question are regulated under the national ambient air quality standard program, §§ [108-110], or the "hazardous air pollutants" program, § [112]. See § [112](d)(1).[7]

This definitive statement from the Supreme Court effectively resolves the matter. In 2012, EPA promulgated the Mercury and Air Toxics Standard,[8] which regulated emissions of mercury and other hazardous pollutants from new and existing coal- and oil-fired EGUs under Section 112 of the Clean Air Act. According to the plain language of the statute, then, once EPA promulgated the Mercury and Air Toxics Standard, the Agency relinquished its authority to subject existing coal- and oil-fired EGUs to regulation under Section 111(d). The Proposed Rule is thus facially invalid because it seeks to regulate sources – existing coal-fired EGUs – that are already subject to regulation under Section 112. To the extent EPA argues that the Supreme Court's definitive statement regarding Section 111(d) is dictum because that issue was not directly before the Court in *American Electric Power*, we note that under the law of the D.C. Circuit, even "dicta of the United States Supreme Court should be [considered] very persuasive."[9].

EPA would be bound by the plain language of the Clean Air Act's prohibition even if the Supreme Court had not yet so clearly recognized it. EPA itself correctly acknowledges that the Proposed Rule is invalid under a "literal reading" of Section 111(d).[10] Nevertheless, EPA apparently believes the Section's explicit prohibition is made ambiguous by a clerical mistake in the 1990 Amendments to the Clean Air Act. Before the 1990 Amendments, Section 111(d) barred EPA from regulating, under that Section, "any air pollutant . . . included on a list published under . . . [Section] 112(b)(1)(A)."[11] Two provisions in the 1990

---

[6] 42 U.S.C. § 7411(d) (2006); *see also* 1 U.S.C. §204(a) (2006) (providing that the Code of Laws of the United States current at any time "shall . . . establish prima facie the laws of the United States . . . .").
[7] 131 S.Ct. 2527, 2537 n.7 (2011).
[8] 77 Fed. Reg. 9304 (February 16, 2012).
[9] *Gabbs Exploration Co. v. Udall*, 315 F.2d 37, 39 (D.C. Cir. 1963); *see also Bangor Hydro-Elec. Co. v. FERC*, 78 F.3d 659, 662 (D.C. Cir. 1996) (stating that "Supreme Court dicta ten[d] to have somewhat greater force" that dicta from other courts).
[10] *Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units* ("Legal Memo") 26 (June 18, 2014), *available at* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602-legal-memorandum.pdf.
[11] 42 U.S.C. §7411(d) (1987).

Amendments purported to alter that language. The first provision, drafted in the House, replaced the cross-reference to "112(b)(1)(A)" with the language that now appears in the U.S. Code and that is cited by the Supreme Court in *American Electric Power*, forbidding EPA from regulating emissions of "any pollutant . . . from a source category which is regulated under Section 112."[12] The second provision, drafted in the Senate, struck "[112](b)(1)(A)" and inserted "in lieu thereof '[112](b).'"[13] Rushing to file its conference report after an all-night meeting, the House-Senate Conference Committee included both amendments in the version of the 1990 Amendments that was ultimately passed by both houses of Congress and signed into law by the President.

2. The substantive House amendment of Section 111(d) nullifies the Senate conforming amendment.

The House provision of Section 111(d) prohibiting double regulation of sources is the law under longstanding rules for resolving drafting inconsistencies and clerical errors in federal legislation. A longstanding rule of legislative draftsmanship dictates that conforming amendments be applied *after* substantive amendments. Congress placed the Senate amendment with other amendments expressly designated as "Conforming Amendments." Congress's decision to label the Senate amendment as a "conforming amendment," and to lump the amendment with a host of other conforming amendments, conclusively demonstrates that the Senate amendment was a clerical revision, not intended to affect the substance of Section 111(d). The House amendment, on the other hand, is clearly substantive.

A close analysis of the text of the amendment reinforces the conclusion that the Senate amendment is clerical. Conforming amendments are, by definition, non-substantive. They are:

> amendment[s] of a provision of law that [are] necessitated by the substantive amendments or provisions of the bill. The designation includes amendments, such as amendments to the table of contents, that formerly may have been designated as clerical amendments.[14]

---

[12] Pub. L. No. 101-549, § 108, 104 Stat. 2399 (1990).
[13] *Id.* at § 302(a).
[14] Senate Legislative Drafting Manual § 126(b)(2)(A); *see, e.g.*, *I.N.S. v. Stevic*, 467 U.S. 407, 428 (1984) ("The amendment . . . was explicitly recognized to be a mere conforming amendment, added 'for the sake of clarity,' and was plainly not intended to change the standard."); *Dir. of Revenue of Mo. v. CoBank ACB*, 531 U.S. 316, 323 (2001) (conforming amendment was "merely . . . technical," rather than substantive).

The function of the Senate amendment was to update Section 111(d)'s existing language to reflect changes made by other provisions of the 1990 Amendments. A few of those provisions replaced Section 112(b)(1)(A)—the subsection cross-referenced in Section 111(d)—with Sections 112(b)(1), 112(b)(2), and 112(b)(3). The Senate amendment sought to accommodate those changes by "striking" Section 111(d)'s cross-reference to Section 112(b)(1)(A) "and inserting in lieu thereof '[112](b).'"[15] It is thus plainly clerical or conforming.

In contrast, the House amendment significantly and deliberately alters the scope of Section 111(d). Whereas the pre-amendment version of Section 111(d) allowed EPA to regulate certain emissions from source categories regulated under Section 112,[16] the House amendment expressly precludes EPA from using Section 111(d) to regulate any emissions from source categories regulated under Section 112.[17] The substantive character of the House amendment is confirmed by its placement amidst a series of other obviously substantive amendments in the Statutes at Large.[18]

Significantly, the House's substantive amendment *eliminates* the statutory cross-reference that the Senate's conforming amendment was intended to update, because it replaces the cross-reference with an entirely new substantive limitation on EPA's authority. Without a cross-reference to update, the Senate amendment is superfluous, enacting nothing. The U.S. Code version of Section 111(d) accordingly notes that the Senate's clerical change "could not be executed."[19] Inclusion of the Senate amendment in the final version of the 1990 Amendments was thus a mistake. EPA itself has described the Senate amendment as "a drafting error" that "should not be considered."[20]

Longstanding judicial and legislative practice support this plain text reading of the U.S. Code. In *Chickasaw Nation v. United States*, for example, the Supreme Court concluded that "a failure to delete an inappropriate cross-reference" in a statute was "simply a drafting mistake" that "d[id] not warrant rewriting

---

[15] Pub. L. No. 101-549, § 302(a).
[16] *See* 42 U.S.C. § 7411(d) (1987).
[17] Pub. L. No. 101-549, § 108, 104 Stat. 2399 (1990).
[18] *See Beecham v. United States*, 511 U.S. 368, 371 (1994) ("That several items in a list share an attribute counsels in favor of interpreting the other items as possessing that attribute as well.").
[19] Revisor's Note, 42 U.S.C. § 7411.
[20] 70 Fed. Reg. 15,993, 16,031 (Mar. 29, 2005).

the remainder of the statute's language."[21] Circuit courts across the country have similarly held that, where a mistake in correcting a cross-reference conflicts with the statute's substantive provisions, the mistake should be treated as "the result of a scrivener's erro[r]" and not construed as "creating an ambiguity."[22] On the dozens of occasions where simultaneously-enacted substantive and conforming amendments have applied to the same statutory language, the Office of the Revisor of Statutes has refused to give effect to the conforming amendment, without exception.[23] Indeed, even though such errors are relatively common in complicated pieces of legislation, Congress and the courts appear not to have ever given effect to one.

Nevertheless, EPA insists the Senate amendment must be given effect on the ground that federal agencies are obligated to give substantive effect to all language in the Statutes at Large.[24] EPA does not attempt to square its reading with the judicial and legislative precedents that preclude giving effect to drafting errors.[25] Nor does EPA suggest a principled means of distinguishing between the Senate amendment and the hundreds of other drafting errors interspersed throughout the U.S. Code.[26] Although no court or agency has ever given effect to such errors, EPA would require courts and agencies to do so for each of the hundreds of erroneous clerical amendments heretofore denied effect.

3. Even when read together, the House and Senate amendments to Section 111(d) prohibit double regulation of source categories under Sections 111(d) and 112.

In light of the foregoing, EPA's attempt to give meaning to both amendments is misguided. Only the House's has any effect. Even accepting there is something to reconcile, EPA's attempt goes badly

[21] 534 U.S. 84, 90-91 (2001); *see also U.S. Nat'l Bank of Or. v. Indep. Ins. Agents of Am., Inc.*, 508 U.S. 439, 462 (1993) (unanimous court disregarded placement of quotation marks in statute when, after reviewing in detail the statute's "structure, language, and subject matter," it concluded that the statute's "true meaning" was "clear beyond question," and that "the placement of the quotation marks in the [statute] was a simple scrivener's error, a mistake made by someone unfamiliar with the law's object and design").

[22] *Am. Petroleum Inst. v. SEC*, 714 F.3d 1329, 1336-37 (D.C. Cir. 2013); *see also United States v. Coatoam*, 245 F.3d 553, 557 (6th Cir. 2001) (declining to give effect to erroneous statutory cross-reference); *In re Chateaugay Corp.*, 89 F.3d 942, 954 (2d Cir. 1996) (same); *King v. Hous. Auth.*, 670 F.2d 952, 954 n.4 (11th Cir. 1982) (same).

[23] *See, e.g.*, Revisor's Note, 7 U.S.C. § 2018; Revisor's Note, 10 U.S.C. § 18237; Revisor's Note, 16 U.S.C. § 5953; Revisor's Note, 21 U.S.C. § 860; Revisor's Note, 21 U.S.C. §886a; Revisor's Note, 22 U.S.C. § 2577; Revisor's Note, 26 U.S.C. § 219; Revisor's Note, 29 U.S.C. § 1053; Revisor's Note, 31 U.S.C. § 5131; Revisor's Note, 38 U.S.C. § 3015; Revisor's Note, 40 U.S.C. § 11501; Revisor's Note, 42 U.S.C. § 2991b-1; Revisor's Note, 42 U.S.C. § 297e; Revisor's Note, 49 U.S.C. § 47115.

[24] Legal Memo 26.

[25] *See supra* notes 12-15 and accompanying text.

[26] *See supra* note 14 and accompanying text.

astray, because under any proper harmonization of the two versions, the existence of the House amendment explicitly forecloses adoption of the Proposed Rule.[27] It is undisputed that the plain text of the House amendment curtails EPA's authority to regulate pollutants emitted by sources regulated under Section 112. Put another way, Section 111(d) cannot provide a statutory basis for the Proposed Rule unless EPA demonstrates both that the Senate amendment *must* be given effect (which, as we have shown, cannot be done), *and* that giving effect to the Senate amendment makes it *impossible* to give full effect at the same time to the House amendment's plain language. EPA has not made this showing, and it cannot make this showing, because the two amendments can be harmonized in way that gives full effect to both.

EPA's attempt at such a showing[28] is unavailing. The limitations in the House and Senate amendments are entirely compatible with one another.[29] The House amendment forbids EPA from regulating, under Section 111(d), any pollutants emitted from sources in a source category already regulated under Section 112[30]; the Senate amendment forbids EPA from regulating, under Section 111(d), any hazardous air pollutants, whether or not they are emitted from a source in a category regulated under Section 112.[31] Nothing in either restriction on EPA's authority forecloses full enforcement of the other. Rather, EPA may give maximum effect to both limitations by reading the two amendments as *jointly* prohibiting EPA from regulating under Section 111(d) any hazardous air pollutants already regulated under Section 112, *as well as* any emissions of any pollutants from a source in "a source category which is regulated under Section 112."[32]

Not only is such a harmonized construction reasonable, it is mandatory. A venerable maxim of statutory construction requires courts and agencies to give effect, whenever possible, to *all* of the language

[27] Pub. L. No. 101-549, § 108.
[28] Legal Memo 25-26 (citing arguments made in preamble to *Revision of December 2000 Regulatory Finding of the Emissions of Hazardous Air Pollutants from Electric Utility Steam Generating Units and the Removal of Coal- and Oil-Fired Electric Utility Steam Generating Units from the Section 112(c) List*, 70 Fed. Reg. 15,994, 16,029-32 (Mar. 29, 2005)).
[29] *See, e.g.*, William J. Haun, *The Clean Air Act as an Obstacle to the Environmental Protection Agency's Anticipated Attempt to Regulate Greenhouse Gas Emissions from Existing Power Plants*, THE FEDERALIST SOC'Y (Mar. 2013); Brian H. Potts, *The President's Climate Plan for Power Plants Won't Significantly Lower Emissions*, 31 YALE J. REG. ONLINE 1, 9 (Aug. 22, 2013).
[30] Pub. L. No. 101-549, § 108.
[31] *Id.* at § 302(a).
[32] 42 U.S.C. § 7411(d).

in a statute.[33] EPA's reading gives meaning only to the Senate amendment (and then only to portions thereof, as we explain next), entirely ignoring the House's. Because it is possible to give concurrent effect to all of the language in the House and Senate amendments, as we have shown above, EPA *must* do so. Of course, giving effect to the House amendment's express terms renders the Proposed Rule invalid, because the Proposed Rule purports to regulate, under Section 111(d), emissions of pollutants from sources (coal-fired EGUs) in a source category (the category of coal- and oil-fired EGUs) already regulated under Section 112 by virtue of the Mercury and Air Toxics Standards.

Rather than adopt this straightforward reading of the two amendments, EPA has propounded its own, novel interpretation of Section 111(d). Under EPA's interpretation, Section 111(d) would prohibit regulation of "any [hazardous air pollutants] listed under Section 112(b) that may be emitted from a particular source category . . . regulated under Section 112."[34] Somewhat remarkably, EPA's interpretation ignores the explicit limitations set out in *both* of the amendments it purports to construe. Contrary to the House's substantive amendment - which explicitly bars any regulation under Section 111(d) of any existing *sources* already regulated under Section 112 - EPA's interpretation would allow such regulation so long as the *pollutant* is not regulated under Section 112. Contrary to the Senate's conforming amendment - which appears to forbid regulation of *any* hazardous air pollutant under Section 111(d) - EPA's reading would permit such regulation of the hazardous air pollutant so long as the emitting source is not regulated by Section 112. All that remains after EPA's exercise in statutory transmogrification is a version of Section 111(d) that is substantially less restrictive than what is prescribed by either the House or Senate amendments, a version on which no house of Congress has ever voted.

Without any support, EPA suggests the express limitations in the House and Senate amendments *negate* one another. But, as the Supreme Court very recently made clear, "an agency may not rewrite clear statutory terms to suit its own sense of how the statute should operate."[35] Because it is possible to read

[33] *Reiter v. Sonotone Corp*., 442 U.S. 330, 339 (1979); *United States v. Menasche*, 348 U.S. 528, 538 (1955); *Ward v. Race Horse*, 163 U.S. 504, 508 (1896).
[34] Legal Memo 26.
[35] *Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427, 2446 (2014).

Section 111(d) in a way that gives maximum effect to both the House and Senate amendments, EPA *must* do so. The unambiguous effect of such a reading is to prohibit EPA from regulating, under Section 111(d), emissions of any air pollutant from sources in a category that is already regulated under Section 112. The Proposed Rule violates this prohibition, and thus Section 111(d) cannot supply the statutory basis for enacting it. As there is no other source of authority, EPA must abandon the Proposed Rule to the extent that it purports to regulate sources already regulated under Section 112 - here, coal-fired EGUs.

4. Even if Section 111(d) were ambiguous, EPA's proposed interpretation is not entitled to deference.

To determine whether an agency's interpretation of a statute is valid, courts employ the familiar framework from *Chevron, U.S.A. v. Natural Resources Defense Council, Inc.*[36] and its progeny. The first step in that framework asks "whether Congress has spoken to the precise question at issue."[37] If so, the agency must give effect to Congress's expressed intent.[38] If the statute is ambiguous or silent on the question at issue, however, courts ask whether the ambiguity or silence is the product of an implicit delegation of interpretive authority to the agency by Congress.[39] If not, courts will afford the agency's interpretation of the statute only the modest deference outlined in *Skidmore v. Swift & Co.*[40] If the ambiguity or silence is the product of an implicit delegation of authority to the agency, then and only then, under the second *Chevron* step, will courts defer to the agency's interpretation if that interpretation is reasonable.[41] EPA's interpretation of Section 111(d) fails at each step in the *Chevron* analysis.

a. Any conflict between the House and Senate amendments does not create the sort of ambiguity that would warrant *Chevron* deference for EPA's proposed interpretation of Section 111(d).

Even if the House and Senate amendments render Section 111(d) ambiguous, the Proposed Rule is still invalid. To justify the Proposed Rule, EPA has adopted an interpretation of Section 111(d) that departs

---

[36] 467 U.S. 837, 842-43 (1984).
[37] *Id.* at 842.
[38] *Id.*
[39] *United States v. Mead Corp*., 553 U.S. 218, 226-27 (2001).
[40] *Id.* at 234-35 (citing *Skidmore*, 323 U.S. 134, 139-40).
[41] *Chevron*, 467 U.S. at 843.

substantially from Section 111(d)'s text. For that reason, the validity of EPA's interpretation of Section 111(d) hinges on its receiving the substantial deference afforded under *Chevron*. Such deference, however, is unwarranted here and almost certainly will not be accorded by the reviewing courts.

Not every statutory question gives rise to *Chevron* deference. As Chief Justice Roberts stated just this past Term, "Direct conflict [between statutory provisions] is not ambiguity, and the resolution of such a conflict is not a statutory construction but legislative choice. *Chevron* is not a license for an agency to repair a statute that does not make sense."[42] Rather, *Chevron* deference is appropriate only when it is clear Congress meant for the alleged ambiguity in the statute to "be resolved, first and foremost, by the agency, and desired the agency (rather than the courts) to possess whatever degree of discretion the ambiguity allows."[43] In other words, *Chevron* deference only applies where there is intent to delegate to the agency the authority to interpret.

In Section 111(d), there is no evidence that Congress drafted and passed the House and Senate amendments with the intention of creating an ambiguity that it meant for EPA to interpret. Rather, as EPA has acknowledged, inclusion of the Senate amendment was an inadvertent "drafting error."[44] A drafting error cannot supply a basis for affording *Chevron* deference, since, by definition, a mistake conveys no congressional intent at all —delegatory or otherwise.[45] Without *Chevron* deference, EPA's interpretation of Section 111(d), which either concededly conflicts with the statute's plain language or simply ignores one house's amendment in favor of another's, cannot survive.

Cases like *National Association of Home Builders v. Defenders of Wildlife*[46] and *Citizens to Save Spencer County v. EPA*[47] are not to the contrary. *National Association of Homebuilders* involved separate statutes addressing separate problems through "seemingly categorical—and, at first glance,

[42] *Scialabba v. Cuellar de Osorio*, 134 S. Ct. 2191, 2214 (2014) (Roberts, C.J., concurring).
[43] *Smiley v. Citibank (S.D.), N.A.*, 517 U.S. 735, 740-41 (1996); *see also Am. Bar Ass'n v. F.T.C.*, 430 F.3d 457, 469 (D.C. Cir. 2005) ("The deference mandated by *Chevron* comes into play . . . only if the reviewing court finds an implicit delegation of authority to the agency.").
[44] 70 Fed. Reg. 15,993, 16,031 (Mar. 29, 2005).
[45] *See Appalachian Power Co. v. EPA*, 249 F.3d 1032, 1043-44 (D.C. Cir. 2001) ("Lest it obtain a license to rewrite the statute, however, we do not give an agency alleging a scrivener's error the benefit of *Chevron* step two deference, by which the court credits any reasonable construction of an ambiguous statute.").
[46] 551 U.S. 644 (2007).
[47] 600 F.2d 844 (D.C. Cir. 1979).

irreconcilable—legislative commands."[48] The Court ultimately deferred to an agency interpretation reconciling the two statutes, largely because of the interpretive canon disfavoring repeal by implication.[49] That canon is not applicable in these circumstances, so neither is the deference afforded under *National Association of Homebuilders*.

Similarly, *Spencer County* involved two distinct Sections of the Clean Air Act that appeared to set out different effective dates affecting construction of major pollution-emitting facilities.[50] Not only has the D.C. Circuit subsequently cabined that decision,[51] but *Spencer County*, like *National Association of Homebuilders*, addressed circumstances fundamentally dissimilar to those surrounding Section 111(d). With Section 111(d), two separate versions of a single section of a public law purport to address, in vastly different ways, the very same language in a single subsection of a statute. Those facts bear little resemblance to the facts in *National Association of Homebuilders* and *Spencer County*, both of which involved ambiguities created by *different* sections of the U.S. Code.

There is, in short, no basis for affording EPA's interpretation of Section 111(d) *Chevron* deference. Without such deference, EPA's interpretation of Section 111(d) cannot be sustained, as it is manifestly contrary to the statute's express terms.

b. EPA's reading of Section 111(d) is not entitled to *Chevron* deference because it is unreasonable.

Deference under step two of *Chevron* would be inappropriate here even had Congress delegated to EPA authority to interpret any alleged ambiguity in Section 111(d), because EPA's interpretation is profoundly unreasonable. "Under the second step of *Chevron*, [courts] will only defer to [an agency's] interpretations if they are reasonable and consistent with statutory purpose."[52] Yet EPA's construction of Section 111 contravenes even EPA's own understanding of congressional intent. As EPA admits, a central

---

[48] 551 U.S. at 661.
[49] *Id.* at 662-69.
[50] 600 F.2d at 852-53.
[51] *See Georgetown Univ. Hosp. v. Bowen*, 821 F.2d 750, 757 n.11 (D.C. Cir. 1987) ("The decision in *Spencer County* is not only extremely limited, but the narrow exception that it purports to recognize has never been accepted by any other panel of this court.").
[52] *GTE Serv. Corp. v. F.C.C.*, 205 F.3d 416, 422 (D.C. Cir. 2000); *see also FDIC v. Philadelphia Gear Corp*., 476 U.S. 426, 439 (1986) (agency interpretation "may certainly stand" where it "is consistent with congressional purpose").

purpose of the 1990 Amendments was "to change the focus of Section 111(d) by seeking to preclude [Section 111(d)] regulation of those pollutants that are emitted from a particular source category that is actually regulated under Section 112," so as to preclude "duplicative or overlapping regulation."[53] Despite this understanding, EPA now proffers a reading of Section 111(d) that contravenes that congressional intent.

Section 111(d)'s prohibition against double-regulation of existing sources is part of a carefully considered regulatory scheme concerning emissions from stationary sources. The existing scheme avoids subjecting existing sources to both new national standards for emissions under Section 112 and new state-by-state standards under Section 111. Unlike newly-constructed sources, which may be designed and constructed in compliance with both Section 111 and Section 112, the imposition of additional regulatory burdens on *existing* sources sacrifices fairness and all but ensures creation of a huge stranded asset problem.

The problems presented by double regulation of existing sources are starkly illustrated by this Proposed Rule. As we discuss in Section I.D.3 below, many coal-fired EGUs have invested hundreds of millions of dollars in pollution controls to comply with the Mercury and Air Toxics Standard, which was promulgated just two years ago pursuant to Section 112. It has been estimated that implementation of that rule will cost those plants more than $9 billion annually.[54] Under the double regulation threatened by this Proposed Rule, however, many of these facilities will be forced to shut down entirely, or curtail their generation so significantly that their continued operation is no longer economically viable. There will be no opportunity to recover the substantial investments made in state-of-the-art pollution controls. This defies all reason and fairness, and is plainly contrary to congressional intent.

Additionally, existing sources that were built under a different regulatory regime may lack the technological or financial flexibility to comply with two separate sets of rules – one under Section 111(d) and another under Section 112. For this reason, Section 111(d) and Section 112 require EPA to weigh the

[53] 70 Fed. Reg. 15,993, 16,031 (Mar. 29, 2005).
[54] EPA, *Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards* 3-13 (Dec. 2011), *available at* http://www.epa.gov/ttn/ecas/regdata/RIAs/matsriafinal.pdf.

cost of compliance against maximum achievable reductions.[55] By requiring that regulation of existing sources occur *either* under Section 112 *or* under Section 111(d), Congress deliberately avoided imposing two independent regulatory regimes on existing sources, recognizing that such duplicative efforts could transform these assets into liabilities. EPA's proposal to impose double regulatory burdens on existing sources is contrary to existing law and public policy.

B. The Proposed Rule is unlawful because EPA may not regulate CO_2 emissions from existing units in a source category pursuant to Section 111(d) without first adopting a valid rule governing CO_2 emissions from new units in the same source category.

Section 111(d)(1)(A) directs that EPA require States to establish standards of performance for "any existing source for any pollutant . . . *to which a standard of performance would apply if such source were a new source.*"[56] EPA therefore may not issue regulations under Section 111(d) to regulate emissions from existing sources until it has adopted standards of performance under Section 111(b) for pollutants from *new* sources within the same source category. Because no valid predicate Section 111(b) rule exists for CO_2 emissions from coal- or gas-fired power plants, the Proposed Rule exceeds EPA's authority under Section 111(d).

EPA claims that two new proposed rules will independently satisfy Section 111(d)'s predicate rule requirement if they are finalized.[57] The first of the proposed rules (the Proposed New Source Rule) would establish standards of performance for greenhouse gas emissions from new electric utility generating units.[58] The second proposed rule (the Proposed Modified and Reconstructed Source Rule) would set standards of performance for emissions of greenhouse gases from certain modified and reconstructed electric utility generating units.[59] These two proposed rules for new and modified and reconstructed sources, however, are themselves invalid.

[55] 42 U.S.C. §§ 7411(a)(1), 7411(d), 7412(d).
[56] 42 U.S.C. §7411(d)(1)(A) (emphasis added).
[57] Legal Memo 12-13.
[58] *Standards of Performance for Greenhouse Gas Emissions from new Stationary Sources: Electric Utility Generating Units*, 79 Fed. Reg. 1,430 (Jan. 8, 2014).
[59] *Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units*, 79 Fed. Reg. 34,960 (June 18, 2014).

1. The Proposed New Source Rule cannot serve as the Section 111(b) predicate rule because the Proposed New Source Rule is invalid.

EPA first claims that its Proposed New Source Rule is a sufficient Section 111(b) predicate rule because the Proposed New Source Rule sets standards of performance governing CO_2 emissions from new coal- and gas-fired power plants. But EPA's analysis on this point is fatally flawed, because the Proposed New Source Rule does not establish a valid "standard of performance" for coal-fired EGUs. Instead, it proposes to require the implementation of a technology – carbon capture and storage (CCS) – that has not been adequately demonstrated as required by statute.

Section 111(a)(1) of the Clean Air 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*.[60]

A system of emission reductions is "adequately demonstrated" when it "has been shown to be reasonably reliable, reasonably efficient, and . . . reasonably expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way."[61] An emissions standard based on technology not fitting within that definition cannot be a "standard of performance," and, thus, cannot serve as a valid Section 111(b) predicate rule.

EPA's Proposed New Source Rule relies on partial implementation of CCS, a system that has not been "adequately demonstrated," at coal-fired EGUs. CCS is at most a nascent, untested emissions reduction system. At a minimum, it requires: (1) the use of largely-undeveloped technology to capture CO_2 emissions; and (2) access to relatively rare geological formations that are capable of storing CO_2. For reasons set out at length in comments EPA received in response to the Proposed New Source Rule, neither the capture nor the storage component of CCS has been "adequately demonstrated" to date. That means the Proposed New Source Rule does not set out a valid standard of performance, and thus the whole Proposed New Source Rule is invalid. Because an invalid rule cannot serve as the necessary Section 111(b) predicate

---

[60] 42 U.S.C. § 7411(a)(1) (emphasis added).
[61] *Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973).

for the Proposed Rule, the Proposed Rule cannot be sustained. EPA must develop a new NSPS before it may proceed with any existing source emission guideline.

2. The Proposed Modified and Reconstructed Source Rule cannot serve as the requisite Section 111(b) predicate rule because it treats modified and reconstructed sources as existing sources.

Clearly aware of the profound flaws in its proposed NSPS, EPA suggests that the Proposed Modified and Reconstructed Source Rule can serve as the requisite Section 111(b) predicate rule for the Proposed Rule. EPA's reading here neglects important points about the Proposed Modified and Reconstructed Source Rule and Section 111. In the Proposed Modified and Reconstructed Source Rule, EPA classifies modified and reconstructed sources as *both* new *and* existing sources for purposes of Section 111. Under Section 111(a), however, a source cannot be both *new* and *existing*. The two categories are mutually exclusive, and a source must be classified as one or the other. Specifically, Section 111(a)(2) defines "new source" as "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under [Section 111] which will be applicable to such source."[62] An "existing source," by contrast is "any stationary source *other than a new source*."[63] Thus, by the statute's plain terms, a source that is considered a new source cannot remain an existing source.

Because a source cannot be both *new* and *existing* under Section 111, the question is whether EPA views modified and reconstructed sources as new or existing. According to Section 111(a)(2), once an existing source is modified, it automatically becomes a "new source."[64] The plain text of Section 111 thus indicates that EPA's Proposed Modified and Reconstructed Source Rule applies to "new sources," meaning it *could* qualify as a predicate new-source rule for purposes of Section 111(d) under normal circumstances.

These are not normal circumstances, however. In its proposed rules, EPA has created a topsy turvy regulatory regime in which the proposed emission reduction goals for existing sources will be *far more stringent* than the proposed goals for modified/reconstructed sources and even, in many States, new

[62] 42 U.S.C. § 7411(a)(2).
[63] *Id.* at § 7411(a)(6)(emphasis added).
[64] *Id.* at § 7411(a)(2).

sources. Ordinarily, one would expect the NSPS to be the most stringent regulations issued under Section 111, as new sources presumably can install the most current, state-of-the-art technology to reduce their emissions of a pollutant and can make the siting, design, and other decisions necessary to facilitate the installation and operation of such technologies. Standards applicable to modified and reconstructed sources should ordinarily be subject to the next most stringent standards, as sources undergoing such modifications or reconstructions are in a position to make *some* technological or operational changes to lower their emissions. Existing source emission guidelines issued under Section 111(d) *should be* the least stringent. As the Act suggests, such sources generally have limited remaining useful lives and are subject to other factors significantly limiting their ability to reduce emissions absent a modification or reconstruction. This appears to have been Congress' intent in subjecting new and modified sources to strict, EPA-guided regulation under Section 111(b), while subjecting existing sources to more relaxed, State-guided regulation under Section 111(d).

EPA departs wildly from this commonsense regime, and in the process creates perverse incentives for sources to modify or reconstruct for the express purpose of avoiding regulation under the highly stringent proposed new source standard and finding refuge under the relatively more lenient standard proposed for modified and reconstructed sources.[65]

EPA attempts to deal with this significant problem by regulatory sleight-of-hand: it states that sources that modify or reconstruct will be subject to the modified/reconstructed source standard, but also states that they will remain subject to any Section 111(d) standard then in effect. In other words, EPA proposes to treat modified and reconstructed sources as being both *new* sources and *existing* sources *at the same time*. However, this is impermissible under the plain terms of the statute. As noted previously, under Section 111(a), the categories of new sources and existing sources are mutually exclusive. A source may

[65] EPA expressly recognizes the perverse incentives its suite of proposed rules creates. 79 Fed. Reg. at 34,904 (explaining that one reason for EPA's otherwise inexplicable attempt to subject modified and reconstructed sources to the Section 111(d) standard "is to avoid creating incentives for sources to seek to avoid their obligations under a CAA section 111(d) plan by undertaking modifications. The EPA is concerned that owners or operators of units might have incentives to modify purely because of potential discrepancies in the stringency of the two programs, which would undermine the emission reduction goals of CAA section 111(d).").

not belong to both categories at once. Thus, to the extent that EPA wishes to treat modified and reconstructed sources as *existing* sources subject to the proposed Section 111(d) standard, it may not at the same time contend that they are *new* sources subject to a Section 111(b) standard. Because this is exactly what EPA does, the modified/reconstructed source rule cannot serve as a predicate for issuance of the very same Section 111(d) standard to which those sources would be subject.

It is far more consistent with the statute to treat modified and reconstructed sources as *new* sources subject to regulation under Section 111(b). In that case, however, EPA may not continue to subject those sources to regulation under the Section 111(d) standard, as such a standard may only be applied to *existing* sources. That the regulations EPA has proposed create perverse incentives to modify or reconstruct is no fault of the sources in the category. Rather, it is a consequence of EPA's vast overreach in proposing an existing source standard that is far more stringent than either the modified/reconstructed source proposal or, in many cases, the proposed NSPS.

The crux of the matter is this: EPA may only categorize modified sources as either new or as existing. It may not treat such sources as both. More specifically, the Agency may not cherry pick and treat modified sources as "new" for establishing a predicate rule, yet "existing" for purposes of subjecting them to continued regulation under the existing source rule. If EPA opts to treat modified and reconstructed sources as existing sources, then, contrary to EPA's assertions, the Proposed Modified and Reconstructed Source Rule *cannot* serve as the requisite Section 111(b), new-source predicate rule for the Proposed Rule. In either case, EPA cannot regulate modified and reconstructed sources under the Proposed Rule.

II. Even if Section 111 grants EPA authority to promulgate an existing source rule, EPA's sole authority under that Section is limited to defining BSER for the affected facilities

With its proposed regulation of CO_2 emissions from existing fossil fuel-fired EGUs, EPA has grossly overstepped its lawful authority under CAA Section 111(d). Fundamentally, EPA has erred in three ways: first, by attempting to define BSER to include things other than technological or operational measures that can be applied to each affected facility in the designated category; second, by going well beyond its statutorily-specified, limited role of defining BSER; and third, by usurping the States' role of establishing and applying the standards of performance and thereby eviscerating the cooperative federalism principles enshrined in CAA Section 111(d).

A. The Proposed Rule is inconsistent with the Clean Air Act because it purports to define BSER as including more than technological and operational measures that reduce emissions during the operation of an affected facility.

In the Proposed Rule, EPA stretches the statutory term "system of emission reduction" far beyond the limits of text and tradition. Whereas "system of emission reduction" has long been understood to mean technological and operational improvements that can be made *at a specific unit*,[66] EPA's Proposed Rule stretches the term to encompass any and all activities that tangentially pertain to demands on the electric grid as a whole. Stepping well beyond the limits of BSER, EPA posits that, under the guise of Section 111(d), it can direct a host of unprecedented activities: the re-dispatch of power from coal-fired EGUs to lower-emitting natural gas-fired EGUs; re-dispatch from fossil fuel-fired EGUs to non-emitting renewable energy sources and nuclear power plants; and, demand drastic reduction of electricity demand by end users for the sole purpose of reducing GHG emissions from EGUs. In short, EPA proposes to define BSER so the Agency may: (1) require reductions that are obtained from sources other than the "affected facility"; (2) require reductions that are obtained through facilities and measures that are or apply beyond the regulated source category; and (3) effectively define reduction or elimination of demand for a good as a means of controlling emissions associated with the production of that good.

In drafting this proposal, the EPA asserts that its judgment about what it believes makes sense for reducing CO_2 should trump the judgment that every utility board, every state governor, every state legislature, every state PUC, every Independent System Operator, every Regional Transmission Organization, and the Federal Energy Regulatory Commission have ever made about how best to balance a myriad of critical values and practical considerations affecting the electric utility industry, including safety; reliability; the affordability of power; economic and industrial development; development of new demand-side, generation, and delivery infrastructure; development of new technologies; the management of resources in the short- and long-term; the management of a broad range of market, fuel, delivery, and

[66] *See infra* Part II.B.1.

operational risks; compliance with a long list of environmental regulations for air, water, solid waste, and endangered species; land use management; and much, much more. It has arrogated to itself effectively the power to re-regulate the entire energy economy for the purpose of controlling just one pollutant.

Such virtually limitless power cannot be squared with the carefully circumscribed authority Congress gave EPA in Section 111(d). As the Supreme Court said in *Utility Air Regulatory Group v. EPA*, "When an agency claims to discover in a long-extant statute an unheralded power to regulate 'a significant portion of the American economy,' … we typically greet its announcement with a measure of skepticism."[67] Rather, the Court "expect[s] Congress to speak clearly if it wishes to assign an agency decisions of vast economic and political significance."[68] EPA's proposed takeover of the energy sector is precisely the type of previously unheralded power about which the Court was speaking.

Instead of outlining a finite system of BSER applicable to a designated existing source, EPA has prescribed a vague laundry list of items that, in its view, might conceivably lead to emissions reductions, and styled their ad hoc assembly the "best system of emission reduction." EPA's proposed BSER is no system at all. Rather, it is simply a takeover of the electric generating and consumption market by an Agency that has no authority to regulate in that area, in contravention of the Supreme Court's warning in *UARG*. Moreover, EPA's decision to brand unrelated items as "Building Blocks" does nothing to transform disparate items—many of which do not even relate to the source category EPA purports to be regulating—into an acceptably determinate *system* of means for obtaining emission reductions.

Only one of EPA's "blocks," Building Block 1 heat-rate improvements, makes any attempt to curtail emissions from designated facilities themselves. Although the proposed Building Block 1 measures and targets are unlawful for other reasons, as discussed in other portions of these comments, Building Block 1 is the *only* block of the four EPA proposes that aims to accomplish what *all* BSER is required to do: derive improvements from an existing source and consider the remaining useful life of the facility in determining whether and, if so, to what extent, to require such reductions.

---

[67] 135 S. Ct. 2427, 2444 (June 13, 2014) (internal citations omitted).
[68] *Id.*

EPA suggests that, in determining BSER under Section 111(d), it may take directly into account emission reductions that come from the *substitution* of generation from EPA-favored generation sources (like gas-fired units and renewable sources) in the place of generation from EPA-disfavored existing sources (like coal-fired EGUs). Inclusion of such "outside-the-fence-line" and "beyond-the-source-category" measures in BSER is contrary to both law and past practice. Section 111(d) requires EPA to establish procedures and emissions guidelines, and each State to then develop "a plan which establishes standards of performance for *any existing source* for any air pollutant." EPA clearly misunderstands both the term "performance" and the term "existing source."

B. The Proposed Rule illegally redefines "Standards of Performance" to include factors that have nothing to do with the environmental performance of EGUs.

EPA can only arrive at a beyond-the-fence definition of "standards of performance" for existing sources by first redefining "performance." Performance should logically be read to mean the amount of emissions attributable to a given generation output from a particular source. EPA implicitly redefines the term, to instead mean the total amount of emissions from the source category, even where that requires a particular unit to be used less or shut down altogether. Such a reading of the term "performance" would allow EPA to use the Clean Air Act to simply require Americans to use less of those technologies that EPA believes could be replaced by better substitutes. For example, instead of regulating the level of emissions produced by gas lawnmowers over a specified number of hours of use (a true standard of performance), EPA could require Americans to use scythes or old fashioned reel mowers to mow their lawns. Instead of regulating the level of emissions produced by cars over a specified number of miles (again, a true standard of performance), EPA could require States to force consumers to use motorcycles, bicycles, or public transit if their commutes exceed an EPA-approved distance. Instead of regulating the level of emissions produced by trucks over a specified number of miles, EPA could require States to force businesses to ship their products by rail – even if there were not sufficient rail capacity at the time the rule issued to carry all the required freight. EPA could assume, as it does here, that the states will somehow ensure that the necessary infrastructure is constructed, even though they lack authority over interstate rail shippers. Instead of regulating the level of emissions from paper mills, EPA could require States to force businesses to convert to "paperless" workplaces and outlaw printing emails and other documents. As these examples suggest, EPA's approach is both lawless and boundless.

1. EPA's Proposed Rule Illegally redefines "Source" and "Source Category" to include activities by entities other than owners or operators of regulated sources.

The Act and its regulations define "stationary source," as "any building, structure, facility, or installation which emits or may emit any air pollutant."[69] Emissions controls under Section 111(d) must apply directly to "a single building, structure, facility, or installation—the unit prescribed in the statute," rather than to a *combination* or agglomeration of such units.[70] EPA's implementing regulations make it clear that these standards and reductions apply to individual units. For example, when EPA's regulations speak of "increments of progress" toward compliance with a standard of performance, they refer expressly to the steps "which must be taken by *an* owner or operator of *a designated facility*" in order to achieve that compliance.[71] The regulations call for each state plan to "adopt emission standards and compliance schedules *applicable to designated facilities*," to obtain information about compliance at "designated facilities," and to require testing and recordkeeping at "designated facilities."[72]

EPA's "portfolio approach," in the Proposed Rule, which is predominately composed of "outside-the-fence" measures for reducing emissions, plainly exceeds this statutory and regulatory limitation. In particular, three of EPA's four proposed Building Blocks can *only* be achieved when multiple facilities operate in coordination with one another—through emission averaging, allowance trading, demand-side reductions, and re-dispatching generation from one facility to another. Such an expansive approach to BSER effectively defines the entire category of existing electric generating units **and** the consumers of the electricity as a single source under the CAA and bases the "standards of performance" on emissions reductions that are only available through changes in the industry and economy *as a whole*, rather

[69] 40 C.F.R. § 60.2.
[70] *Asarco Inc. v. EPA*, 578 F.2d 319, 322 (D.C. Cir. 1978).
[71] 40 C.F.R. § 60.21.
[72] 40 C.F.R. § 60.26.

than those that may be achieved at any individual "building, structure, facility, or installation." Section 111(d)'s emphasis on "individual building[s], structure[s], facility[ies], [and] installation[s]" does not permit so broad an approach.

Even if EPA could base BSER on factors other than what is demonstrated and achievable for particular sources, it would be manifestly unreasonable for it to do so. Past EPA guidance documents have acknowledged this limitation. Addressing new source performance standards under Section 111, EPA explained, "For listed *source categories*, EPA must establish 'standards of performance' that apply to *sources* that are constructed, modified or reconstructed after EPA proposes the NSPS for the relevant source category."[73]

Even under a permissive reading of Section 111's BSER requirement, EPA is limited to regulating within a distinct source category. Yet EPA's Proposed Rule goes well beyond the limits of the specified source category to define BSER based on its highly inexpert assumptions as to how States could or should regulate renewable energy sources, nuclear power plants, and end-user energy efficiency improvements. It is difficult to discern how a regulation intended to limit CO_2 emissions *from fossil-fuel-fired power plants* arrives at such far-reaching regulation of EGUs, non-emitting power generators, energy markets, electric transmission and gas infrastructure, and even energy consumers, that are not within the identified source category. Indeed, the effect of EPA's definition is to lump nearly every conceivable producer and user of electric energy together as a single "source category" for BSER purposes. That definition is ultimately unworkable, since it renders the term "source category" a nullity and results in EPA regulating the generation, dispatch, and consumption of energy, rather than just "systems of emission reduction" designed to reduce specific sources' emissions.

Never before has EPA adopted emissions guidelines based on such "outside-the-fence" considerations. This is not surprising, since EPA's longstanding regulations focus on technological and

[73] EPA, *Background on Establishing New Source Performance Standards (NSPS) Under the Clean Air Act* 1 (Sept. 2013), *available at* http://www2.epa.gov/sites/production/files/2013-09/documents/111background.pdf.

operational measures that can be implemented at a specific unit.[74] Since Section 111(d)'s enactment, EPA has promulgated regulations for specific source categories in 13 instances.[75] In each instance, those standards have been technological or operational standards that can be applied specifically to each designated facility. Such an approach harmonizes with Section 111's handling of "stationary sources" of air pollutants.

For instance, in its final rule promulgating new source performance standards and existing source emission guidelines for municipal solid waste landfills, EPA determined that BSER for MSW landfills comprised "a well-designed and well-operated gas collection system and [] a control device capable of reducing [the pollutant of concern] in the collected gas by 98 weight-percent."[76] Operational standards for each existing landfill were also promulgated to ensure that each landfill was operated according to best practices to minimize emissions.[77] No suggestion was made that BSER included shuttering some landfills in favor of others employing more modern or lower-emitting technologies, or that BSER could or should include efforts to minimize consumers' generation of municipal waste (even though that might have been one of the more effective measures in reducing emissions from MSW landfills).

---

[74] *See, e.g.*, 40 C.F.R. § 60.21(h) (referring to "emission control equipment" and "process changes," both of which are unit-specific measures).

[75] *See Regulation of CO2 Emissions from Existing Power Plants Under § 111(d) of the Clean Air Act: Program Design and Statutory Authority*, R. Nordhaus and I. Gutherz, 44 ELR 10366, 10372 n. 57 (2014). According to the authors, the 13 are: Phosphate Fertilizer Plants; Final Guideline Document Availability, 42 Fed. Reg. 12,022 (Mar. 1, 1977); Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist, 42 Fed. Reg. 55,796 (Oct. 18, 1977); Kraft Pulp Mills, Notice of Availability of Final Guideline Document, 44 Fed. Reg. 29,828 (May 22, 1979); Primary Aluminum Plants, Notice of Availability of Final Guideline Document, 45 Fed. Reg. 26,294 (Apr. 17, 1980); Emission Guidelines; Municipal Waste Combustors, Final Emission Guidelines, 56 Fed. Reg. 5,514 (Feb. 11, 1991), withdrawn & superseded by 60 Fed. Reg. 65387 (Dec. 19, 1995) (same source category); Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule, 61 Fed. Reg. 9,905 (Mar. 12, 1996); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Hospital/Medical/Infectious Waste Incinerators, Final Rule, 62 Fed. Reg. 48,348 (Sept. 15, 1997); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units, Final Standards and Guidelines, 65 Fed. Reg. 75,338 (Dec. 1, 2000); Emission Guidelines for Existing Small Municipal Waste Combustion Units, Final Rule, 65 Fed. Reg. 76,378 (Dec. 6, 2000); Clean Air Mercury Rule, 70 Fed. Reg. 28,606; Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Other Solid Waste Incineration Units, Final Rule, 70 Fed. Reg. 74,870 (Dec. 16, 2005); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units, Final Rule, 76 Fed. Reg. 15,372 (Mar. 21, 2011).

[76] 49 Fed. Reg. at 9907.

[77] *Id.* at 9907-08.

Almost all of the remaining existing source emission guidelines EPA has promulgated have been for categories of solid waste combustors regulated under Section 129 of the Clean Air Act[78] as well as under Section 111.[79] For existing sources in such categories, Section 129 requires that EPA issue guidelines that are based on maximum achievable control technology (MACT), the same standard applicable to emissions of hazardous air pollutants under Section 112.[80] Though MACT is more stringent than the standard for sources that are governed only by Section 111(d), none of the guidelines EPA has promulgated for solid waste combustors requires shuttering one combustor in favor of another with lower emissions or requires their owners or operators to endeavor to reduce the volumes of wastes generated as a means of reducing emissions.[81] With its Proposed Rule, however, EPA has proposed BSER that sweeps in a host of actors (e.g. end-users) and entities that are neither "stationary sources" nor members of the designated source category.

NRECA finds it telling, as well, that for both the NSPS and the modified/reconstructed source standard that are companions to this Proposed Rule, EPA has proposed BSER that are confined to source-specific, inside-the-fence measures: partial CCS for new coal-fired EGUs, NGCC for new gas-fired units, and source-specific emission rates for both modified and reconstructed coal- and gas-fired sources in the category. If beyond-the-fence and beyond-the-category measures like those in Building Blocks 2

[78] 42 U.S.C. § 7429.

[79] Emission Guidelines; Municipal Waste Combustors, Final Emission Guidelines, 56 Fed. Reg. 5514 (Feb. 11, 1991), withdrawn & superseded by 60 Fed. Reg. 65387 (Dec. 19, 1995) (same source category); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Hospital/Medical/Infectious Waste Incinerators, Final Rule, 62 Fed. Reg. 48348 (Sept. 15, 1997); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units, Final Standards and Guidelines, 65 Fed. Reg. 75338 (Dec. 1, 2000); Emission Guidelines for Existing Small Municipal Waste Combustion Units, Final Rule, 65 Fed. Reg. 76378 (Dec. 6, 2000); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Other Solid Waste Incineration Units, Final Rule, 70 Fed. Reg. 74870 (Dec. 16, 2005); and Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units, Final Rule, 76 Fed. Reg. 15372 (Mar. 21, 2011).

[80] *See, e.g.*, Municipal Waste Combustors NSPS and EG, 60 Fed. Reg. at 65,390 ("Under Section 129 of the Clean Air Act, the standards and guidelines adopted for MWC's must be based on MACT.")

[81] In EPA's Clean Air Mercury Rule, EPA promulgated a final NSPS and EG that would have required a cap-and-trade program as part of the BSER. That rule provides no support for EPA's approach here, both because it was vacated by the D.C. Circuit, *see State of New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008), and because the cap-and-trade program was actually a compliance mechanism rather than a means of calculating the required reductions. EPA expressly determined in that rule that the cap-and-trade was part of BSER only because it was "based on control technology available in the relevant timeframe" for reducing mercury emissions from each plant. 70 Fed. Reg. at 28,617, 28,620. That plants could choose either to install the controls or instead to purchase allowances from other sources that did install controls does not undercut the fundamental point: that even the Clean Air Mercury Rule was based on a "system of emission reduction" – mercury controls – that could be applied at each designated facility in the source category.

through 4 were properly encompassed within the statute and EPA's regulations, then it would be hard to fathom how they could be appropriate components of BSER for existing sources, but not for new, modified, or reconstructed sources.

EPA's proposed BSER cannot be reconciled with the plain language of Section 111, with EPA's own regulations, or with Agency or judicial interpretations of Section 111. It is overbroad and well beyond what is permissible under the Clean Air Act.

2. Building Blocks 2 through 4 are impermissibly based on substituting generation from resources outside the source category for generation from coal-fired units, rather than achieving greater operational environmental efficiency at those units.

As noted, only Building Block 1 (heat-rate improvements at individual affected facilities) arguably falls within EPA's authority under Section 111(d). EPA's three remaining Building Blocks lie far afield of any lawful authority EPA may exercise under Section 111(d). Rather than prescribe systems of emission reduction that can produce lower emissions from specific designated facilities, EPA has proposed an assembly of "blocks" that succeeds only in curtailing productive generation from designated facilities rather than curtailing their emissions per unit of goods produced.

In particular, Building Block 2 (which defines BSER based on EPA's inexpert assumption that States can and should shift dispatch from coal- to natural gas-fired units) is impermissible, because rather than improve the operations of coal-fired units, it simply demands that such units operate less; it shifts the burden of generating to units lacking common ownership and compatible contractual obligations and belonging to separate regional transmission organizations. EPA is not reducing an existing sources' emission rate, or improving the source's environmental performance (as instructed by the Clean Air Act); it is simply curtailing or eliminating the underlying activity without lawful authority. If such a destructive approach is lawful BSER, then for any source of any pollutant EPA could simply order the source to curtail its operations or shut down. Reduced utilization is not BSER. If reduced utilization impairs viability of the source, it cannot be part of the best system of emission reduction. Tellingly, in the over 68 previous NSPS rulemakings, EPA has never promulgated a NSPS regulation requiring reduced unit utilization.

Building Block 3 (which defines BSER based on EPA's inexpert assumption that States can redispatch certain amounts of generation from fossil fuel-fired to non-GHG-emitting sources such as renewable energy or nuclear generation) is impermissible for similar reasons. It effectively commands fossil fuel-fired units to run less or not at all. In addition, because it purports to require emission reductions through the production of electricity from renewable energy sources and nuclear power plants, it unlawfully regulates sources that are outside the identified source category.

Moreover, nowhere does Section 111 authorize EPA to extend its jurisdiction beyond stationary sources by attempting to regulate *demand* for a good, service, or product. Building Block 4, which requires increases in end-user energy efficiency and other efforts to reduce demand for electricity, sits far outside EPA's lawful authority. In particular, Building Block 4 looks to derive "emission reductions" from something over which utilities have no control: efficiencies that might be gained through consumer efforts. With Building Block 4, EPA seeks to expand its oversight beyond all limits. To search for efficiencies outside the source, the source category, and the activity of generation is to conceive of regulating nearly all U.S. electricity usage. Nearly everything requires energy, and the majority of energy comes from existing units. Those elements of the Proposed Rule contemplating obtaining emission reductions through reduced demand for electricity expand EPA authority beyond anything Congress ever intended to grant the Agency in the Clean Air Act. As the Supreme Court warned in *UARG*, such expansion cannot proceed without *clear congressional authorization*.[82] Section 111 authorizes EPA to regulate emissions of pollutants from existing units within an identified source category, not societal behavior in general.

In addition to being unlawful, EPA's outside-the-fence and outside-the-source-category Building Blocks are counter-productive. Forcing units to operate at sub-optimal levels and shut down for a season at a time in order to meet the goals hurts performance and significantly and adversely affects a unit's heat rate, as discussed in III.B. below. The result is that the hobbled unit emits more pollutants per unit of energy produced than it would if it were running at optimal levels. Thus, if EPA finalizes the guidelines for existing

[82] *Supra* note 67 ("EPA's interpretation is also unreasonable because it would bring about an enormous and transformative expansion of EPA's regulatory authority without clear congressional authorization").

sources as proposed, the result will be a national fleet of fossil fuel-fired power plants emitting *more* greenhouse gases into the air for every kWh of electricity produced than they did before the Guidelines came into effect. Such a result reveals the arbitrary and capricious nature of the Proposed Rule.

Rather than pushing for incremental improvements in emission performance through unit-specific, applied technology as required under the Clean Air Act, EPA has proposed significant curtailment or complete cessation of operations at many of the Nation's existing power plants. Not only is this poor policy, but it is unsupported by any lawful authority under Section 111. Nowhere does the Clean Air Act instruct or permit EPA to shutter the Nation's existing energy infrastructure. Nor is such a drastic expansion of authority the type of change that Congress authorizes through vague implication. Building Blocks 2 through 4 must be dropped from EPA's definition of BSER.

3. If any one of EPA's "Building Blocks" is invalid, the entire BSER as defined by EPA must be stricken.

EPA states in the preamble that the individual Building Blocks are severable, such that the invalidity of one or more of them would not invalidate the other Building Blocks.[83] However, an agency's declaration that a regulatory provision is severable is not determinative; it only gives rise to a *presumption* of severability.[84] The ultimate decision concerning severability must be made by a court, not the EPA.[85]

The standard for severability as established in *Alaska Airlines, Inc. v. Brock* is clear: Courts must first determine whether Congress intended the provisions to operate separately, and then whether the provisions can function separately if it did.[86] The same standard of severability applies to regulations.[87] The Section 111(d) rule cannot satisfy the *Alaska Airlines* two-prong test.

Despite EPA's assertion that the Building Blocks are severable, those Blocks cannot function independently. As noted elsewhere in these comments, for instance, operating a coal-fired EGU at sub-optimal levels (a result of applying any or all of Building Blocks 2 through 4) will adversely affect its

[83] 79 Fed. Reg. at 34,892.
[84] *I.N.S. v. Chadha*, 462 U.S. 919, 931-32 (1983).
[85] *Id.*
[86] *Alaska Airlines, Inc. v. Brock*, 480 U.S. 678, 684-85 (1987).
[87] *Free Enterprise Fund v. Public Co. Accounting Oversight Board*, 130 S. Ct. 3138, 3161 (2010).

heat rate, thus hindering it from achieving the emission reductions required under Building Block 1. EPA has not explored these interrelationships in the preamble, because it simply assumes all four Building Blocks will be finalized. Accordingly, if one or more of the Blocks is invalid, the entire system must be stricken until EPA has properly assessed whether the remaining Block or Blocks still constitute BSER.[88]

Further, despite EPA's claims regarding severability, it is not clear from the proposal whether EPA would in fact have relied on remaining Blocks as "BSER" once invalid Blocks were stricken. Elsewhere in its proposal, for example, EPA asserts that if reductions under one Building Block do not materialize, the necessary emission reductions must come from the other Building Blocks. Indeed, the individualized state emission reduction targets are set assuming that all of the required reductions can be obtained from the other building blocks should one be stricken. That means the Building Blocks are not independent, but rather are closely and inextricably related. This weighs against severability. If any of the Building Blocks is invalid, EPA must revisit the entire structure of its proposal. At a minimum, EPA must recalculate state emission reduction targets, since the targets assume the validity and implementation of all four Building Blocks.

C. The Proposed Rule violates the Clean Air Act because it arrogates to EPA authority that is expressly reserved to the States to establish standards of performance and to apply them to individual existing sources.

1. The Proposed Rule exceeds EPA authority under the Clean Air Act by setting binding standards of performance for the States in the Proposed Rule instead of establishing only BSER.

Under Section 111(d), neither state nor EPA officials possess sufficient authority on their own to determine both the appropriate methods for obtaining and the degree of emission reductions that can be obtained from existing units. Instead, Section 111(d) embodies the principle of cooperative federalism, making distinct and exclusive delegations of authority to federal and state officials that complement one another in establishing standards for existing sources. With its proposed rule, EPA blatantly violates this principle and the statute's plain language, effectively usurping from the States all power to determine what emission reductions can be obtained from existing units.

[88] *See, id.*

Under Section 111(d)(1), the "Administrator shall prescribe regulations which shall establish a procedure similar to that provided by Section 7410 of this title [SIP provisions] under which *each State* shall submit to the Administrator a plan which establishes standards of performance for any existing source for any air pollutant." 42 C.F.R. § 7411(d)(1)(emphasis added). In other words, wholly unlike Section111(b), under which EPA itself sets the standards of performance for new sources, Section111(d) specifically reserves *to the States* the authority to set performance standards for existing sources. EPA has important authority under Section 111(d), but that authority is limited to: (1) developing regulations that establish the *procedures* by which the States arrive at and submit their plans and standards, and (2) identifying a finite, adequately-demonstrated system of emission reductions – the BSER – upon which the States are to rely in setting and applying the applicable standards of performance. *Id*.

Despite the statute's clear command that EPA is to set only the "procedure" and identify BSER, and that the States are to "establish standards of performance" for existing sources and apply those state-developed standards "to any particular source…tak[ing] into consideration, among other factors, the remaining useful life of the existing source," the Proposed Rule relegates States to the ministerial role of implementing and enforcing the substantive standards of performance and specific, state-wide emission reduction goals that EPA has predetermined in the rule. This bold interpretation cannot be squared with the plain text of the statute or the cooperative federalism principles the Clean Air Act embodies.

That this interpretation cannot stand finds support in an often-overlooked provision of Section 111 – Section 111(c). Section 111(c) provides that:

> Each State may develop and submit to the Administrator a procedure for *implementing and enforcing* standards of performance for new sources located in such State. If the Administrator finds the State procedure is adequate, he shall delegate to such State any authority he has under this chapter to implement and enforce such standards. [89]

Section 111(c) contemplates *precisely* the process EPA has proposed for its Section 111(d) rule: EPA issues standards of performance, and the States implement and enforce those standards. However, by its express terms, Section 111(c) applies only to "standard of performance for new sources" promulgated under

[89] 42 U.S.C. § 7411(c)(1) (emphasis added).

Section 111(b). It very conspicuously *does not apply to standards issued under Section 111(d)*. That Congress made Section 111(c) applicable to new source performance standards issued under Section 111(b) and not to existing source standards developed under Section 111(d) is telling. It clearly indicates that, under Section 111(d), the States are not limited to mere implementation and enforcement as EPA has proposed, and that Congress knew how to limit the States' roles where it intended to do so.

Had Congress intended what EPA proposes here – to limit the States to implementation and enforcement of EPA-promulgated standards of performance for existing sources as well as new sources – it would not have stated in Section 111(b) that EPA shall "establish Federal standards of performance for new sources" and in Section 111(c) that "[e]each State may develop and submit to the Administrator a procedure for implementing and enforcing standards of performance for new sources located in such State," and then created a very distinct regime for existing sources under Section 111(d) that assigns to States the duty to "submit to the Administrator a plan which [] *establishes standards of performance for any existing source* for any air pollutant …[and] *provides for the implementation and enforcement* of such standards of performance."[90] EPA's arguments that Section 111(d) is somehow ambiguous on this point are meritless. Section 111(c) shows that Congress knew how to create such a division of responsibility between EPA and the States. That it did not do so in Section 111(d) resolves the matter.

Though it casually discards it here, EPA has long recognized its own limited role in developing state-specific existing source emission guidelines. For instance, in the preamble to EPA's 1975 rules establishing the framework for the development of existing source emission guidelines, EPA explained that it used the term "emissions guidelines" rather than "limitations" to make it clear that any guidelines EPA issued for existing sources were not binding requirements but rather merely "criteria for judging the adequacy of State plans."[91] In its Proposed Rule, however, EPA grossly oversteps this limit to set EPA-developed, state-specific emission reduction targets that the States have no ability to alter. In so doing,

[90] 42 U.S.C. § 7411(d)(1)(A) and (B) (emphasis added).
[91] State Plans for the Control of Certain Pollutants from Existing Facilities, 40 Fed. Reg. 53,340, 53,343 (Nov. 17, 1975). See Attachment A.

the Agency has set precisely the type of binding "limits" that both the statute and EPA's regulations prohibit.

2. The Proposed Rule unlawfully displaces State authority to develop a standard of performance and apply that standard on a unit-by-unit basis.

a. The Proposed Rule violates the statutory and regulatory mandate that the States establish Standards of Performance.

Section 111(d) instructs EPA to issue regulations under paragraph 111(d) that "*shall permit* the State in applying a standard of performance to any particular source under a plan submitted under this paragraph *to take into consideration, among other factors, the remaining useful life of the existing source* to which such standard applies."[92] Congress thus imposed on EPA a duty to permit States to consider each particular source in its jurisdiction and to establish standards of performance based on those sources' individual remaining useful lives. Section 111(d) further instructs EPA to allow States to consider other, unspecified factors when applying standards of performance to individual existing sources. The regulation EPA adopted in response to Congress's instruction identifies some of these. The regulation states that:

> States may provide for the application of *less stringent emissions standards or longer compliance schedules* than those otherwise required [under the paragraph setting emissions standards for designated pollutants the Administrator determines may cause or contribute to endangerment of public health], provided that the State demonstrates with respect to such facility (or class of facilities): (1) *Unreasonable cost of control* resulting from plant age, location, or basic process design; (2) *Physical impossibility* of installing necessary control equipment, or (3) *Other factors* specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.[93]

This regulation thus authorizes States to adopt lower emissions standards and longer compliance schedules for individual sources and for source categories and subcategories so long as the State can justify the lower standards on grounds of unreasonable cost, physical impossibility, and other relevant factors. Such justification can only be reached following careful, facility-by-facility consideration of site-specific factors such as age, location, design, and technological compatibility, and other factors such as the inability of a rural electric consumer to bear the high cost of electricity that might accompany excessive emission

[92] 42 U.S.C. § 7411(d)(1) (emphasis added).
[93] 40 C.F.R. 60.24(f) (emphasis added).

reduction requirements. Recognizing that EPA lacks the information and local knowledge necessary even to identify all of the relevant factors affecting implementation of BSER, the CAA and the EPA's general NSPS regulation contemplate that the States will determine what these factors are and how they apply to any particular existing source within its borders.

Other longstanding EPA regulations also bear out this limitation on EPA's authority, expressly prohibiting EPA's issuance of binding emission limits in a Section 111(d) rule. Section 60.22 of those regulations specifically limits EPA to issuing only a nonbinding "guideline document" "containing information pertinent to control of the designated pollutant from designated facilities."[94] EPA also specifies the purely informational purpose of these guidance documents:

> Guideline documents published under this Section *will provide information for the development of State plans*, such as:
>
> > (1) *Information* concerning known or suspected endangerment of public health or welfare caused, or contributed to, by the designated pollutant.
> >
> > (2) A *description* of systems of emission reduction which, in the judgment of the Administrator, have been adequately demonstrated.
> >
> > (3) *Information on the degree of emission reduction which is achievable* with each system, together with information on the costs and environmental effects of applying each system to designated facilities.
> >
> > (4) *Incremental periods of time normally expected* to be necessary for the design, installation, and startup of identified control systems.
> >
> > (5) *An emission guideline* that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities, and the time within which compliance with emission standards of equivalent stringency can be achieved. The Administrator will specify different emission guidelines or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate.
> >
> > (6) *Such other available information as the Administrator determines may contribute to the formulation* of State plans.[95]

EPA's conspicuous use of the words "guidance" and "information" throughout this regulation demonstrates that "information" is all that EPA is authorized to provide the States. The regulation does not authorize EPA

[94] 40 C.F.R. § 60.22.
[95] 40 C.F.R. § 60.22(b) (emphasis added).

to issue emission "guidelines," like the present proposal, that contain binding state-wide emission reduction goals and that are thus "guidelines" in name only.

While EPA may change these longstanding regulations through the ordinary rulemaking procedures (i.e. notice-and-comment rulemaking), it has not done so here, and it may not propose a rule that conflicts with its existing rules and regulations.[96] Such a rule is inherently arbitrary, capricious, and contrary to law.[97] If EPA wishes to depart from its past rules and regulations by finalizing a rule that contains binding statewide emission reduction targets (assuming, for sake of argument, the statute allows that), it must first revise the underlying rules and regulations through a proper rulemaking, explaining the change.[98] It has neither done so nor proposed to do so in this case.

EPA cannot finalize the Proposed Rule because it arrogates to the Agency a function that statute and existing regulations make the exclusive province of the States: the setting of the state-specific standards of performance.

b. The Rule violates the Act's mandate that the individual States determine the extent to which to apply their standards of performance to individual sources.

Subsections of Section 111 also express clear congressional intent to require the promulgation of standards applicable *to individual sources*. When managing emissions from existing units, Section 111 anticipates the States will be "applying a standard of performance *to any particular source*."[99] In so prescribing, the statute outlines two expectations: (1) States will look with particularity at specific units applying standards of performance, and (2) EPA's guidelines must allow States to make prudential assessments about the remaining useful life of particular existing units and other source-specific factors in

[96] *National Environmental Development Ass'n's Clean Air Project v. EPA*, __ F.3d __, No. 13-1035 (D.C. Cir. May 30, 2014) (EPA could not adopt guidance document providing for region-specific applications of aggregation policy where existing regulation required nationwide applicability of a single policy); *Wisconsin Electric Power Co. v. Reilly*, 893 F.2d 901, 919 (7th Cir. 1990) ("We cannot grant deference, however, where the EPA has attempted to implement the [Clean Air] Act's lofty goals in contravention of its own statutory regime.").
[97] *See, e.g.*, *National Cable & Telecommunications Association v. Brand X Internet Services*, 545 U.S. 967, 981 (2005) ("Unexplained inconsistency is, at most, a reason for holding an interpretation to be an arbitrary and capricious change from agency practice under the Administrative Procedures Act.").
[98] *Id.*
[99] 42 U.S.C. 7411(d)(1)(B) (emphasis added).

determining the extent to which to apply those standards to each unit. The principle focus of the standard-setting process must thus be whether the unit itself can meet the prescribed standards.

Section 111(b), which requires the promulgation of new source performance standards for identified categories of sources, states that the standards of performance it requires shall be applicable to "new sources within such category."[100] "New source" is defined in Section 111(a)(2) to "mea[n] any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this Section which will be applicable to *such source*."[101] That definition clearly prescribes a standard of performance that is applicable to a single, identifiable source.

Similarly, Section 111(d) requires EPA to issue standards of performance "for any existing source … to which a standard of performance would apply if *such source* were a new source…."[102] The definition of "existing source" is tied directly to the definition of "new source": it "means any stationary source other than a new source."[103] Once again, the reference is to "any stationary source" – that is, a single source, rather than a group of sources or a category or subcategory of sources. On top of that, the section provides that EPA's regulations "shall permit the State in applying a standard of performance *to any particular source* under a plan submitted under this paragraph to take into consideration, among other factors, the *remaining useful life of the existing source* to which such standard applies."[104] The fact that Congress expressly referred to each "particular source" and authorized the States to take into consideration "the remaining useful life of *the* existing source" in applying the state-developed standard of performance again indicates that Congress intended the application of such standards to be source-specific, so that they could be implemented at each particular source without forcing a premature shutdown of that source.[105] The fact

[100] 42 U.S.C. 7411(b)(1)(B).
[101] 42 U.S.C. 7411(a)(2) (emphasis added).
[102] 42 U.S.C. 7411(d)(1)(A), (A)(ii).
[103] 42 U.S.C. 7411(a)(6).
[104] 42 U.S.C. 7411(d)(1)(B) (emphasis added).
[105] *See, e.g., Keene Corp. v. United States*, 508 U.S. 200, 208 (1993) ("where Congress includes particular language in one section of a statute but omits it in another…, it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion").

that Congress differentiated between source categories and individual sources within those categories shows that, had Congress intended to delegate to EPA the broad authority to regulate the structure and operations of whole source categories, it would have done so simply by directing that EPA issue standards of performance for the source category, rather than for the individual sources within each source category.

Congress plainly anticipated some units would not be able to meet the most aggressive goals for emission reductions, and it prescribed a procedure to address that problem short of requiring the unit to curtail operations or shut down. Where an EGU *cannot* meet a proposed reduction, the statute indicates that the appropriate solution is for the State to adjust the prescribed standard for that unit.[106] In combination with this instruction in Section 111(d) that the States should be allowed to consider "the remaining useful life of the existing source," Section 111(h) demonstrates that the Clean Air Act did not intend to shutter existing facilities with remaining useful lives. Instead, the Act anticipates that, where improvements can be made to reduce emissions from a specific facility, such improvements shall be made; but where improvements are infeasible, relaxation of the standard is appropriate.[107] To demand otherwise impermissibly treats existing sources like new sources, violating congressional intent to create two distinct classes of units, with a separate, more lenient standard governing existing sources.

In proposing binding, state-specific emission reduction targets based on reductions from *all* units, EPA has impermissibly stripped the States of their statutory authority to develop standards of performance that take into account the remaining useful lives of specific existing facilities. Any stated flexibility to determine how and from which sources emission reductions will be obtained is illusory. A target premised on maximum emission reductions from all units requires precisely that. Simply transferring a facility's emission reduction burden to some other facility or requiring a facility to obtain reductions through external measures is impermissible.

[106] 42 U.S.C. § 7411(d)(1)(B) (State shall be permitted, "in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.").
[107] 42 U.S.C. § 7411(h)(1).

If not substantially revised, the inevitable consequence of the Proposed Rule will be the stranding of assets in contravention of congressional intent. In many, if not most, instances the standards EPA has set are so stringent that they *cannot* be met except by closing or drastically curtailing operations from existing coal-fired EGUs. Table 1, below, summarizes cooperative owned unit closures based on EPA modeling. Including units the modeling projects so little use as to be not economically viable, 21% of cooperative coal generation capacity would be scrapped under this proposal.[108]

Table 1 - EPA Modelled Cooperative Coal Generation Retirements in 2025 State option

Cooperative	Plant Name	MW Owned	
Arizona Electric Power Cooperative	Apache Station 2	175	
Arizona Electric Power Cooperative	Apache Station 3	175	
Western Farmers Electric Cooperative	Hugo 1	440	
Arkansas Electric Cooperative	Independence 1	292.6	
Arkansas Electric Cooperative	Independence 2	294.60	
East Texas Electric Cooperative	Independence 2	60	
Dairyland Power Cooperative	John P. Madgett 1	372	
Northeast Texas Electric Cooperative	Pirkey 1	79	
Oglethorpe Power Corporation	Scherer 1	502.2	
Oglethorpe Power Corporation	Scherer 2	505.8	
Seminole Electric Cooperative	Seminole 1	647	
Seminole Electric Cooperative	Seminole 2	663	
Arkansas Electric Cooperative	White Bluff 1	285.3	
Arkansas Electric Cooperative	White Bluff 2	295.4	
Subtotal			4792MW

EPA Modeled unit yearly operation too low to be economically viable

Cooperative	Plant Name	MW Owned	
Tri-State G&T Association	Springerville	417	
Old Dominion Electric Cooperative	Clover 1	215	
Old Dominion Electric Cooperative	Clover 2	215	
East Texas Electric Cooperative	Plum Point	50	
Subtotal			897MW

[108] EPA modeling has phased out a number of cooperative-owned units, and thus they do not appear in the 2025 base case. These units are not included in the table. These units are not included in the table, but are as follows: Charles Lowman 1, Cooper 1&2, Earl F. Wilson 1, Frank E. Ratts 1SG1 & 2SG1, RD Morrow 1&2, R S Nelson 6, Robert A Reid R1, San Miguel SM-1, and Walter Scott Energy Center 3, totaling 2779 MW and 1723 cooperatively owned MW.

Total MW shutdown			**5689 MW**
			21% of all Coop Coal Generation Capacity

These closures would occur even where the EGU at issue has significant remaining useful life or has made substantial investments in pollution control technology to comply with other EPA regulations. Thus, while EPA's proposal gives lip service to the concept of remaining useful life, in practice any meaningful consideration of remaining useful life would cause a State to miss its EPA-mandated emission reduction target.

This result is contrary to the Section 111(d) implementing regulations, which authorize "States [to] . . . provide for the application of less stringent emissions standards or longer compliance schedules than those otherwise required …, provided that the State demonstrates (1) Unreasonable cost of control resulting from plant age, location, or basic process design; [] (2) Physical impossibility of installing necessary control equipment; or [] (3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable."[109]

Because EPA has proposed aggressive, binding state-wide emission reduction targets, many coal-fired EGUs will be forced to shutter or drastically curtail their operations. Moreover, they will have to do so even if: (1) they cannot reasonably implement the additional heat-rate improvement projects that EPA blithely assumes are available to all units (for instance, if a unit has already undertaken such measures and has no further measures available to it); (2) there are no additional controls the unit could install or operational measures the unit could undertake to reduce its emissions; and (3) the unit would otherwise, under EPA's regulations, be eligible for "application of a less stringent standard or final compliance time," such as if the unit has recently installed costly pollution control equipment to comply with MATS.

The principle of cooperative federalism embedded in the Act and longstanding EPA regulations implementing Section 111(d) is thus rooted in reality and humility: the reality that no Washington agency can ever efficiently attain the local knowledge necessary to make prudent judgments concerning the

[109] 40 C.F.R. § 60.24(f).

effective implementation of BSER across the entire national electricity generation sector, and the humility to recognize this reality. In proposing binding, inflexible State emission reductions targets without respect to the kind of site-by-site analysis provided for in the Act and its own regulations, EPA violates Congress' intent to allow States to adjust standards and emissions controls to fit the fleet of existing sources. In so doing, EPA abandons the principle of cooperative federalism and casts aside humility, placing States in a vise between hard reality and EPA's own regulatory hubris. Its action is thus as unwise as it is unlawful.

3. The Proposed Rule violates the Clean Air Act by not allowing States to consider the "remaining useful life" of existing generation assets when applying standards of performance to particular sources.

The preamble to the proposed rule states that "the proposed BSER, expressed as a numeric goal for each state, provides states with the flexibility to determine how to achieve the reductions (i.e., greater reductions from one building block and less from another) and to adjust the timing in which reductions are achieved, in order to address key issues such as cost to consumers, electricity system reliability and the *remaining useful life* of existing generation assets."[110] The rule as proposed, however, does not in general permit States to consider in any meaningful way the remaining useful life of EGUs within their jurisdiction, or, in particular, to make reasonable adjustments based on "remaining useful life" in a State such as South Dakota, which has only one affected EGU as of January 8, 2014, or, in States such as North Dakota and Wyoming, where best available retrofit technology (BART) was required by EPA and determined to be cost effective on various EGUs based on an assumption (made by EPA) that those EGUs would continue to operate at least 20 years after those technologies were installed.

EPA makes the following request for comment on "remaining useful life" in the proposed rule:

> "…the EPA is proposing that, in this case, the flexibility provided in the state plan development process adequately allows for consideration of the remaining useful life of the affected facilities and other source-specific factors and, therefore, that separate application of the remaining useful life provision by states in the course of developing and implementing their CAA section 111(d) plans is unnecessary. The agency is requesting comment on its analysis below of the implications of the EPA's existing regulations interpreting "useful life" and "other factors" for purposes of this rulemaking. [FN302] The agency also requests comment on whether it would be desirable to include in regulatory text any

[110] 79 Fed. Reg.34,830, 34,836 (June 18, 2014).

> aspects of this preamble discussion about how the provisions in the existing implementing regulations concerning source-specific factors relate to this emission guideline."[111]

The preamble then sets forth three lines of analysis – Legal Background, Implications for Implementation of These Emission Guidelines, Relationship to State Emission Performance Goals and Timing of Achievement – that set forth EPA's reasons for ignoring the plain language of the Section 111(d)(1) requirement that EPA permit States to consider each source's "remaining useful life." Each of these subcategories of analysis is flawed, and the result is a rule that does not meaningfully permit States to consider "remaining useful life" and that is therefore unlawful.

a. The "Legal Background" EPA provides in support of its failure to allow States to consider "remaining useful life" when applying standards of performance to individual units is contradicted by the legislative history of Section 111(d).

EPA claims in the preamble that "EPA's 1975 implementing regulations [FN303] address remaining useful life and other facility-specific factors that might affect requirements for an existing source under section 111(d)."[112] To support this claim, the preamble cites a 1975 rule, 40 CFR § 60.24(f). There are several fatal flaws in the claim that this regulatory provision governs States' consideration of "remaining useful life" in establishing "standards of performance" for each "existing source." First, 40 CFR § 60.24(f) was established in 1975—*before* the 1977 Amendments added the statutory "remaining useful life" language—as the means for the State to make an exception to the "emission standards" guideline established by the EPA Administrator under the language of Section 111(d)(1). 40 CFR § 60.24(f) in its entirety provides:

> (f) Unless otherwise specified in the applicable subpart on a case-by-case basis for particular designated facilities or classes of facilities, States may provide for the application of less stringent emissions standards or longer compliance schedules than those otherwise required by paragraph (c) of this section, provided that the State demonstrates with respect to each such facility (or class of facilities):
>
> > (1) Unreasonable cost of control resulting from plant age, location, or basic process design;
> >
> > (2) Physical impossibility of installing necessary control equipment; or

[111] 79 Fed. Reg. at 34,925.
[112] 79 Fed. Reg. at 34,925.

> (3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

Thus, 40 CFR § 60.24(f) allows States to apply, on a case-by-case basis, "less stringent emissions standards or longer compliance schedules than those otherwise required" by the state-established standard of performance. It was not and has never been a means for States to consider "remaining useful life" as added in the 1977 CAA Amendments. Indeed, the regulation does not even mention "remaining useful life" as a factor. The States' authority to consider that factor, in addition to the factors specified in the regulation, *comes instead directly from the statute*.

In 1975, Section 111(d) stated:

> *(d) (1))* The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 110 under which each State shall submit to the Administrator a plan which(A) establishes <u>emission standards</u> for any existing source for any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 108(a) or 112(b)(I)(A) but (ii) to which a standard of performance under subsection (b) would apply if such existing source were a new source, and (B) provides for the implementation and enforcement of such <u>emission standards</u>.[113] (emphasis supplied.)

The 1977 CAA Amendments changed this language in the following ways:

> (b)(1) Section 111(d)(1) of such Act // 42 USC 7411. // is amended by striking out "<u>emissions standards</u>" in each place it appears and inserting in lieu thereof "<u>standards of performance</u>" and by adding at the end thereof the following new sentence: " <u>Regulations of the administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration; among other factors, the remaining useful life of the existing source to which such standard applies</u>."[114].

The 1977 Amendments thus changed what States can establish under 111(d)(1) from "emission standards" to "standards of performance," and they added a sentence requiring EPA to "permit" States to consider "remaining useful life" "among other factors" in setting standards of performance for each existing source. The 1977 Amendments also added a specific definition of "standard of performance" to cover State authority under § 111(d)(1):

---

[113] CAA § 111(d)(1), 1970 CAA Amendments.

[114] CAA § 111(d)(1), 1977 CAA Amendments to original 1970 language. Underlining is the new substituted or added language.

> Section 111(a)(1) of the Clean Air Act, defining standard of performance, is amended to read as follows:
>
> "(1) The term 'standard of performance' means—,
>
> "(A) with respect to any air pollutant emitted from a category of fossil fuel fired stationary sources to which subsection (b) applies, a standard—,
>
> "(i) establishing allowable emission limitations for such category sources, and
>
> "(ii) requiring the achievement of a percentage reduction in the emissions from such category of sources from the emissions which would have resulted from the use of fuels which are not subject to treatment prior to combustion,
>
> "(B) with respect to any air pollutant emitted from a category of stationary sources (other than fossil fuel fired sources) to which subsection (b) applies, a standard such as that referred to in subparagraph (A)(i); and
>
> "(C) with respect to any air pollutant emitted from a particular source to which subsection (d) applies, a standard ***which the State*** (or the Administrator under the conditions specified in subsection (d)(2)[)] determines is applicable to that source and which reflects the degree of ***emission reduction*** achievable ***through the application of the best system of continuous emission reduction*** which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated for that category of sources.
>
> "For the purpose of subparagraphs (A)(i) and (ii) and (B), a standard of performance shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. For the purpose of subparagraph (1)(A)(ii), any cleaning of the fuel or reduction in the pollution characteristics of the fuel after extraction and prior to combustion may be credited, as determined under regulations promulgated by the Administrator, to a source which burns such fuel."[115] (Emphasis supplied.)

The House Report of the Legislative History clarifies the intent of these 1977 amendments to Sections 111(a)(1) & 111(d)(1):

> The section also makes clear that standards adopted for existing sources under section 111(d) of the act are to be based on available means of emission control (not necessarily technological) and *must*, unless the State decides to be more stringent, *take into account the remaining useful life of the existing sources*.
>
> ….

[115] CAA § 111(a)(1), 1977 CAA Amendments to original 1970 language of 111(a)(1).

> Several other factors necessitate the revisions of present law contained in section 111 of the bill. Among these factors are: … (2) the need to clarify the provisions of section 111(d) relating to existing sources; …
>
> ….
>
> Clarification of Section 111(d)
>
> This section is also intended to clarify the basis for standard-setting for existing sources under section 111(d) of the Act. Under the committee bill, the standards in the section 111(d) State plan would be based on the best available means (not necessarily technological) for categories of existing sources to reduce emissions. The Administrator would establish guidelines as to what the best system for each such category of existing sources is. However, the State would be responsible for determining the applicability of such guidelines to any particular source or sources. *The Administrator's guidelines must take into account the remaining useful life of existing sources*. Unless the State decides to adopt and enforce more stringent standards, the State plan would be expected to take into account the remaining useful life of the source (or sources). [116]

The House Conference Report on the 1977 Amendments further confirms the intent:

> The section also makes clear that standards adopted for existing sources under section 111(d) of the act are to be based on available means of emission control (not necessarily technological) and *must*, unless the State decides to be more stringent, *take into account the remaining useful life of the existing sources*.[117]

In summary, the complete sentence added to Section 111(d) in 1977 provides that "[r]regulations of the administrator under this paragraph *shall permit the State* in applying a standard of performance to any particular source under a plan submitted under this paragraph *to take into consideration, among other factors, the remaining useful life of the existing source* to which such standard applies."[118] (Emphasis supplied.) As the 1977 Act's Legislative History makes clear, the authority of the State to consider "remaining useful life" was considered to be an essential power that States were to have in determining standards of performance for existing sources.

The Proposed Rule fails to include any provisions that meaningfully allow States to consider "remaining useful life." 40 CFR § 60.24(f) does not satisfy that statutory obligation, because it was promulgated in 1975 as means of allowing States to establish on a case-by-case basis "less stringent

[116] P.L. 95-95, CLEAN AIR ACT AMENDMENTS OF 1977, H.R. Rep. 95-294, 1977 WL 16034 **11, 187, 195 (Leg. Hist.) (emphasis added).
[117] P.L. 95-95, CLEAN AIR ACT AMENDMENTS OF 1977, House Conf. Rep. 95-294, 1977 WL 16035 *129 (Leg. Hist.).
[118] 42 U.S.C. § 7411(d)(1).

emissions standards or longer compliance schedules than those otherwise required" by the Administrator's guidelines. It was not intended to be, and does not, allow for consideration of "remaining useful life" as set forth in 111(d) and its Legislative History.

b. EPA's analysis of the "Implications for Implementation of These Emission Guidelines" arbitrarily fails to account for the fact that the Proposed Rule will likely force unit closures decades before they reach the end of their remaining useful lives.

In its discussion of "implications for implementation of these emission guidelines," the Preamble next asserts that the failure of the rule to develop a "remaining useful life" regulation can be addressed by States through the Proposed Rule's general flexibility:

> [B]ecause of the flexibility for states to design their own standards, the states have the ability to address the issues involved with" remaining useful life" and "other factors" in the initial design of those standards, which would occur within the framework of the CAA section 111(d) plan development process. States are free to specify requirements for individual EGUs that are appropriate considering remaining useful life and other facility-specific factors.
>
> Therefore, to the extent that a performance standard that a state may wish to adopt for affected EGUs raises facility-specific issues, the state is free to make adjustments to a particular facility's requirements on facility-specific grounds, so long as any such adjustments are reflected (along with any necessary compensating emission reductions), as part of the state's CAA section 111(d) plan submission. The agency requests comment on its interpretation.[119]

This reasoning is flawed because it does not allow any variation of performance standards when a State's emission standards would force the retirement of a resource ten to twenty years before the end of its remaining useful life, thus stranding huge investments.

Premature retirements and stranded investments are likely to occur under the Proposed Rule. For example, in South Dakota, the Big Stone EGU is in the process of installing a $400 million scrubber based on a cost-effectiveness calculation that the unit's useful life is at least 20 years. As the only "affected steam generating unit" that is a coal-based EGU in South Dakota on January 8, 2014,[120] the only way the proposed emission rate of South Dakota may be achieved may be to retire Big Stone prematurely. As the only coal-based EGU, all the South Dakota reductions fall on this one source, and there is currently no

---

[119] 79 Fed. Reg. at 34,925-26.
[120] Proposed 40 CFR Part 60, Subpart UUUU, 40 CFR § 60.5795, 70 Fed. Reg. at 34,954.

alternative way to make the reductions required under the proposed rule (that fall entirely on this one facility) other than to back it off to levels where it would no longer be economical to operate. In other words, the rule may force shutdown of a source that is currently in the middle of a $400 million pollution control upgrade that was based on a remaining useful life cost-effectiveness calculation that Big Stone would operate at least another 20 years.

The Proposed Rule would also likely cause the shutdown of the three EGUs at the Laramie River Station in Wyoming. EPA has issued a final federal implementation plan (FIP) for this station that would require a total investment of $750 million, or $250 million per unit. EPA based its plan on a cost-effectiveness calculation that assumed each unit would have a remaining useful life of at least 20 years and would continue to operate that long. The CO_2 reductions required for Wyoming under the Proposed Rule in Wyoming may require such steep reductions in production at the three units that it would not be economical to run them, or unit shutdowns, resulting in stranded investments of at least $250 million per unit.

The flexibility EPA purports to grant the states to take into account remaining useful life is illusory. The EPA has proposed binding emissions reductions for the states with a binding deadline for achieving those reductions. Only a small fraction of the reductions – those under Building Block 1 – presume that the coal units continue to operate at present levels through their useful lives. All of the other reductions from Building Blocks 2-4 come from substituting gas, renewable energy, nuclear energy, and energy efficiency for the output from the coal EGUs, in other words shutting them down or ramping them down so far as to make them uneconomic to operate long before the end of their useful lives. Only if states are allowed to establish their own performance standards and compliance schedules as the CAA and EPA regulations direct, can states exercise their statutory obligation to take into account the plants' remaining useful lives.

c. The same failure to account for premature closures and stranded investments fatally undermines EPA's "Relationship to State Emission Performance Goals and Timing of Achievement."

The Preamble of the proposed rule expresses the opinion that premature retirement and stranded investments are adequately addressed by the flexibility built into the rule:

> "The EPA also believes that, because of the way the state-specific goals have been developed in these proposed guidelines, remaining useful life and other facility-specific considerations should not affect the determination of a state's rate-based or mass-based emission performance goal or the state's obligation to develop and submit an approvable CAA section 111(d) plan that achieves that goal by the applicable deadline.[121]

The preamble further opines that:

> [u]nder the proposed guideline, states would have the flexibility to adopt a state plan that relies on emission-reducing requirements that do not require affected EGUs with a short remaining useful life to make major capital expenditures [FN305] or incur unreasonable costs. Indeed, the EPA's proposal would provide states with broad flexibility regarding ways to improve emission performance through utilizing the emissions reduction methods represented by the four "building blocks."[122]

Footnote 305 makes the following comment request regarding this issue:

> The agency requests comment on whether there are circumstances other than a major capital investment that could lead to a prospective state plan imposing unreasonable costs considering a facility's remaining useful life. Where annual costs predominate and/or capital costs do not constitute a major expense, the EPA believes that the remaining useful life of an affected EGU will not significantly affect its annualized cost of control and therefore should not be a factor in determining control requirements for the EGU.

As the above examples show, when a State has a limited number of affected EGUs (in the case of South Dakota, only one), or when most or all of the EGUs are constructed in a short amount of time (LRS in Wyoming, the EGUs in North Dakota all constructed between the mid-70s and mid-80s), the remaining useful lives of such facilities in such States may not be protected under 111(d)(1) *unless EPA allows a different glide path and endpoint date in such States that would allow the continued operation of those facilities at an appropriate but economically viable production level throughout their remaining useful lives*. The present proposal, on the other hand, could result in a sudden and drastic decrease in available generation capacity, either because the sole EGU in a State will retire or because a number of EGUs will retire at once. At LRS in Wyoming, for example, most of the coal-fired EGUs were constructed within approximately a ten-year period (mid-70s to mid-80s) and are currently undergoing significant capital

[121] 79 Fed. Reg. at 34,926.
[122] 79 Fed. Reg. at 34,926.

investments for pollution control to meet various Clean Air Act requirements (Regional Haze BART, Regional Haze reasonable progress, MATS, 316(b), etc.). Forcing premature retirement by limiting hours of operation of these facilities that all have similar remaining useful lives will result in stranded investment and considerable premature and uneconomical investment in new resources. Over the long-term, the net CO_2 emissions from these groups of resources could result in the same reduction over a defined period of time (30 years, for example) by allowing them to operate at an economical level through their remaining useful lives in exchange for a lower rate of emissions over the rest of the defined period of time.

Finally, the preamble states with regard to remaining useful life:

> Remaining useful life and other factors, because of their facility-specific nature, are potentially relevant in determining requirements that are directly applicable to affected EGUs. For all of the reasons above, the agency believes that the issue of remaining useful life will arise infrequently in the development of state plans to limit CO_2 emissions from affected existing EGUs. Even if relief is due a particular facility, the state has an available toolbox of emission reduction methods that it can use to develop a section 111(d) plan that meets its emissions performance goal on time. The EPA therefore proposes that the remaining useful life of affected EGUs, and the other facility-specific factors identified in the existing implementing regulations, should not be considered as a basis for adjusting a state emission performance goal or for relieving a state of its obligation to develop and submit an approvable plan that achieves that goal on time. The agency solicits comment on this position.[123]

The problem of stranded investment and premature retirement may be more common than EPA supposes here, and the toolbox, as proposed, may not be flexible enough in terms of timeframes and glide paths to avoid creating hundreds of millions of dollars of stranded investments at each such facility. As noted above, the EPA's claim that states have a "toolbox" of emission reduction methods that are not relevant to affected EGUs with remaining useful lives is sophistical. That toolbox: gas, nuclear, renewable energy, and energy efficiency do not magically scrub CO_2 from the atmosphere; they reduce CO_2 emissions by displacing generation from higher emitting resources, the very affected EGUs with remaining useful lives about which NRECA is concerned. True offsets should have a place in the states' toolboxes, but that is not enough on its own to resolve NRECA's concerns. These sorts of problems could be avoided altogether, however, if EPA allowed the States meaningful ability to consider the sources' remaining useful lives and other factors

[123] 79 Fed. Reg. at 34,926.

suggesting that a more relaxed standard or a longer compliance period is appropriate for a particular source. Unlike the Proposed Rule, this approach would also have the distinct benefit of complying both with the statute and EPA's longstanding regulations.

4. The Proposed Rule unlawfully denies States the flexibility provided by the CAA and EPA regulations to establish standards of performance that reflect the specific situations faced by cooperatives and similarly situated utilities.

As discussed in section II.C above, the CAA and regulations direct EPA to provide States with broad flexibility to determine the extent to which to apply standards of performance to particular sources and source categories.

That flexibility is particularly important for cooperatives and similarly situated utilities, which will face significant challenges in complying with any standard of performance based on the BSER that EPA has established, making application of less stringent standards much more reasonable for cooperatives and similarly situated utilities than the full application of BSER that EPA has proposed.

EPA appears to understand this fact. For instance, EPA correctly recognizes that many rural electric cooperatives have *very* small fleets of generating assets and that many "may not have as much flexibility [as larger utilities] to control dispatch because they are operating in a competitive market, where they can be in a position in which they need to operate if called upon."[124] Unfortunately, the rule fails to give States the flexibility to address the special circumstances that even EPA admits is needed.

EPA's proposed binding, statewide emission reduction targets are based on unfounded assumptions about the availability of re-dispatch, renewables, and demand reduction. Because these blanket assumptions are baked into EPA's emission reduction goals, and because EPA has made no provision for reducing those statewide emission reduction goals if their assumptions prove unfounded in a specific case, the Proposed Rule unlawfully deprives the States of their ability to truly address cooperatives' and similarly situated utilities' circumstances in a reasonable way.[125]

[124] 79 Fed. Reg. at 34,887.

[125] *See* 42 U.S.C. §§ 7411(a) (specifying "cost of achieving such reduction" in emissions as factor that must be considered in determining BSER), 7411(d) (specifying that "[r]egulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this

Given this fundamental problem with the proposal, NRECA appreciates that EPA expressly invites comment on "whether there are special considerations affecting small rural cooperative or municipal utilities that might merit adjustments to this proposal, and if so, possible adjustments that should be considered."[126]

NRECA welcomes this invitation to comment, and it believes that the proposal requires *substantial revision* to account for the particularly difficult circumstances that rural electric cooperatives and similarly situated utilities face. Recognizing individual unit circumstances, including remaining unit useful life, is not only consistent with the statute but it is a function specifically delegated to the States by Section 111(d) in determining the extent to which to apply any standard of performance to a specific unit or class of units.

Specifically, as we discuss in more detail below, the final federal emission guidelines should recognize that: (1) most rural electric cooperatives have extremely limited portfolios of generating assets and therefore that re-dispatch to gas-fired or renewable energy sources may not be available for many rural electric systems; (2) in many cases they rely on coal-fired EGUs that may be able to make only minimal improvements in heat rate to achieve lower CO_2 emission rates; (3) existing lessor financing arrangements and concerns about creating stranded assets through premature shutdown or curtailment would create significant adverse rate impacts for NRECA members, and these will constrain their ability to comply with EPA's proposal if finalized in its current form; and (4) opportunities for additional demand-side energy efficiency measures in rural areas are likely to be extremely limited due to the rural and largely residential nature of the cooperatives' customers. Moreover, EPA's suggestion that cooperatives build or contract for electric supply from lower-emitting sources is unlikely to be practicable and will result in unreliable electric supply to rural customers at extraordinary rates. Many small investor-owned utilities also face the same

---

paragraph to taken into consideration, among other factors, the remaining useful life of the existing source to which such standard applies"), 40 C.F.R. §§ 60.22(b)(3) (requiring EPA, in promulgating emission guideline documents, to provide States "information on the costs … of applying each system to designated facilities"), 60.22(b)(5) (emission guideline must reflect "the application of the best system of emission reduction (considering the cost of such reduction)"; subcategorization, with "different emission guidelines or compliance times or both for different sizes, types, and classes of designated facilities" is required "when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate.").

[126] *Id.*

challenges caused by limited generation portfolio, coal reliance, and widely dispersed, largely residential customers that cooperatives face.

To solve the problems faced by cooperatives and similarly situated utilities, and to restore the States' statutorily-mandated flexibility, NRECA urges EPA to limit itself to its statutorily prescribed roles of: (1) defining the "procedures" under which the States will develop and submit their plans, and (2) identifying the "best system of emission reduction" that EPA determines has been "adequately demonstrated." Beyond that, EPA should adhere to the statute's express command that *the States* individually be permitted to determine the specific standards of performance to apply to sources within their borders, on a unit-by-unit basis, based on the procedures EPA has developed and the BSER it has properly identified.

a. Most rural electric cooperatives have extremely limited portfolios of generating assets and therefore re-dispatch to gas-fired or renewable energy sources may not be available for many rural electric systems.

The vast portion of cooperative electric generation is coal-fired. Nationwide concerns over natural gas availability prompted the U.S. Congress to enact the 1978 Power Plant and Industrial Fuel Use Act. Although this act was repealed in 1987, during implementation it required all new electric generating facilities to be "coal capable." Due to the capital cost differentials between facilities constructed to be "coal capable" and those designed solely for natural gas use, as well as the historically higher fuel cost of natural gas, the Fuel Use Act economically prohibited new EGUs that were coal-capable from using natural gas as the primary fuel. During the time the relevant portions of the Fuel Use Act were in effect, electric cooperative generation needs grew substantially. As a consequence about 60 percent of cooperative total baseload electric generation was constructed under Fuel Use Act and is coal based.

Because of their location far from other sources of generation, and because of the unique cost constraints they face, many cooperatives lack affordable or practical access to enough gas-fired and renewable energy sources to replace the coal that would be displaced by the new rule. This makes the emission reductions that EPA assumes can be obtained from Building Blocks 2 and 3 unrealistic for many rural electric cooperatives.

b. Only limited improvements in heat-rate are available for many cooperative-owned, coal-fired units.

Electric cooperative owners and operators strive to maintain generation that is both reliable and affordable. Because cost savings are passed directly to members, cooperatives work constantly to ensure that their generating assets are well maintained and operated in a way that maximizes electric output for any given quantity of fuel input. As a consequence, many of the heat-rate improvement projects that EPA assumes that units will be able to undertake to comply with Building Block 1 of the Proposed Rule have already been undertaken, thus making impossible for those units to obtain anything close to the 6% improvement in emission rates that EPA proposes. We detail these heat rate improvement limitations in III.B. below. Moreover, our members' experiences demonstrate that the emission reductions obtainable from heat-rate improvement projects tend to be temporary, and that emissions per megawatt-hour tend to rise as time passes following completion of such a project, even with continued maintenance of the unit, as detailed below in III.B.

c. Rural electric cooperatives face unique constraints resulting from lessor financing arrangements and threat of stranded assets.

The costs imposed by the Proposed Rule will ultimately be borne by cooperatives' members and consumers. Cooperative generators have limited equity available to them. In other words, they are highly leveraged, and cooperative consumers must service the debt on units affected by the rule. In many cases units running even less that 10 percent below their operational norm on a continuing basis would be unable to generate enough revenue to service the outstanding debt on the unit. Running them less (which is what EPA effectively requires when it suggests that cooperatives can build new, lower-emitting units or purchase electricity from lower-emitting sources in lieu of generating it from existing units) will lead to significant financial issues and a very high likelihood of creating stranded assets.

For example, EPA's model presumes that Arizona's Tri-State Generation and Transmission Association, Inc., (Tri-State) coal-fired facility, Springerville Unit 3, will dispatch at such a low level due to environmental dispatch that in reality its continuing operation will no longer be economically viable. EPA modeling projects almost 100% re-dispatch of coal resources in Arizona by 2030. Tri-State built this 417

MW coal-fired unit in 2006 and invested just under one billion dollars in it. The expected useful remaining life of the plant extends until 2066. The Springerville plant is a state of the art coal plant with air pollution controls including bag houses for particulate matter, scrubbers for sulfur dioxide, and selective catalytic reduction for nitrogen oxides. Tri-State will be installing additional controls in 2015 to reduce mercury emissions.

Similarly, based on the EPA's modeling under the proposed rule, Seminole Electric Cooperative's coal-fired generating facilities have been arbitrarily scheduled for retirement well before the end of their useful life. Seminole has invested more than $530 million in environmental control technology and recycling practices – $260 million of which was placed in service less than 5 years ago. To reduce emissions, and as part of Seminole's commitment to their communities, approximately 70% of the byproducts produced at their coal facility are recycled for use in products that consumers use every day, including wallboard and concrete. These continued investments have made Seminole's facility one of the cleanest coal-based power plants in the country. Should the EPA's proposed CO_2 rule be finalized, these costly investments will become stranded assets and Seminole's coal-fired power plant will be forced to close – leaving 300 hard-working, skilled employees without jobs. Additionally, Seminole would have to build or purchase new power generation to replace the electricity produced from its coal-fired facility. Such a drastic and sudden shift in Seminole's power portfolio will not only drive up the cost of electricity for its member cooperatives and member consumers, but could have sweeping unintended consequences for the fragile but recovering workforce and economy in Florida. In fact, as highlighted above in Table1, numerous cooperatives will have units that face premature phase-out, creating stranded assets and consequently state regional economic disruptions.

Considerations such as remaining useful life and stranded assets or stranded investments associated with units are precisely the types of factors that Congress expected States to be able to consider in determining what standard of performance to apply to each specific facility within their individual borders. Yet the Proposed Rule deprives States of that ability.

d. Rural electric cooperatives have fewer opportunities to achieve reductions through demand-side energy efficiency measures than EPA assumes.

The customer base of most rural electric cooperatives is unusual. While most utilities serve a mix of both residential and commercial customers, rural electric cooperatives serve mostly residential consumers.[127] This customer base significantly limits the opportunities for obtaining reductions through demand-side energy efficiency improvements that are available to more traditional utilities.[128] Thus, EPA's across-the-board assumption that a 1.5-percent-per-annum emission reduction can be obtained through Building Block 4 cannot be squared with the particular circumstances that rural electric cooperatives face.

Taken together, these specific examples of the extraordinary challenges and obstacles rural electric cooperatives would face in attempting to comply with the proposed emission guidelines demonstrate the need for state discretion to take these and other relevant considerations into account in determining the extent to which any standard of performance can be applied to cooperative-owned units, whether individually or as a class. States must also be allowed the discretion to take into account the special circumstances of similarly situated utilities.

III. Even if EPA could prescribe binding numerical targets for States, the targets prescribed in the Proposed Rule are unattainable and therefore arbitrary, capricious, and contrary to law.

Clean Air Act Section 111(a)(1) defines "standard of performance" as "a standard for emissions of air pollutions . . . *achievable* through the application of the best system of emissions reduction which . . . has been adequately demonstrated. "[129] This definition assumes *actual achievability*. An infeasible standard is by definition not a valid "standard of performance" under CAA. Nor can an unachievable process be considered the "best" system of emissions reductions. To the extent EPA's proposal prescribes BSER-generated savings assuming a series of actions that the States cannot implement, it is invalid. EPA's

---

[127] *See supra* note 1 and accompanying text.

[128] Billingsley, M.A., I. M. Hoffman, E. Stuart, S. R. Schiller, C. A. Goldman, K. LaCommare, *The Program Administrator Cost of Saved Energy for Utility Customer-Funded Energy Efficiency Programs*, Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division, March 2014, Figure ES-1, p. xii.

[129] 42 U.S.C. § 7411(a)(1) (emphasis added).

current Proposed Rule is based on a host of actions the States cannot themselves take, and it thus creates an unattainable goal that cannot be a valid standard of performance.

A. The Proposed Rule is not BSER because EPA arbitrarily substitutes its judgment on the organization and regulation of the extraordinarily complex, national electric power generation and transmission system for that of FERC and the States.

1. The Proposed Rule fails to account for the incredible complexity individual States face in implementing SIPS for a regional industry.

To understand the limitations of state authority and thus the serious shortcomings of the Proposed Rule, EPA must fully comprehend just how complex the electric industry is. There are a wide variety of industry players, state regulatory structures, and wholesale market structures, each of which has different implications for the States' ability to influence generation investment decisions and generation dispatch decisions.

a. The diversity of the U.S. energy industry

First, at the retail level, some States are largely still regulated as they have been for the past 70 years. In those States, vertically integrated utilities not only provide electric service at retail, but also own and operate some or all of the distribution facilities, transmission facilities, and generation facilities required to provide that service. These vertically integrated utilities serve retail consumers subject to a "regulatory compact." They are obligated to provide all retail consumers in their service territories with safe and reliable power at rates that are subject to significant state regulation. In exchange, the utilities are assured the opportunity to recover their prudently incurred costs plus a reasonable rate of return. Even so, these utilities often purchase some portion of their transmission and power supply needs from others.

Other States decided to restructure their utilities. They opened retail electric service to competition from multiple competitive suppliers who sell power to consumers at unregulated market rates. In some cases, the distribution utilities continued to be permitted or required to sell power to those consumers that did not choose competitive suppliers, and those sales were subject to some level of regulation by the state legislature and/or the state public utility commissions. In many but not all cases, the incumbent utilities were required to divest themselves of their generation assets, selling them to other utilities or to independent power producers. California, Texas, much of the Northeast, and some of the Midwest States restructured their utilities. Traditional vertically integrated utilities continue to operate in most of the Southeast and Northwest and some of the Midwest. Even in States that restructured, cooperative utilities and municipally-owned utilities are often still vertically integrated, but they are often subject to different regulatory requirements than the investor-owned utilities. Some States that restructured since have worked to reinstate traditional regulation.

At the wholesale level, there are also different structures. In California, Texas, the mid-Atlantic, the Northeast, and much of the Midwest, Independent System Operators and Regional Transmission Organizations (ISOs and RTOs) manage the transmission system and operate day-ahead and real-time energy markets, ancillary services markets for those generation services required to ensure the stability of the grid, and in some cases short-term centralized capacity markets. In those markets, some generation is bid into the wholesale markets on a "speculative basis." The owners of generation offer to sell it into the market at a price of their choosing, and that generation is dispatched if it is economic. Many but not all of these generation owners are independent power producers who own generation but do not have any retail load to serve and who have not committed all of their generation to wholesale purchasers in the bilateral market. Much of the large scale renewable generation, some of the nuclear resources, some of the coal generation, and a large portion of the natural gas generation is owned by such independent power producers. Some generation is sold in the bilateral market and self-scheduled by the purchaser. Wholesale customers purchase power directly from generation owners as necessary to manage their portfolios, and they choose when they wish to use the power. Some of the generation is self-supplied and self-scheduled. A utility that owns generation and has wholesale or retail load to serve decides when to dispatch that generation to meet their contractual or legal obligations.

Outside RTO and ISO regions, there are also a range of players involved. Electric utilities with load to serve may use their own generation to do so or they may purchase generation from third parties on a long or short-term basis to meet their power supply needs. Those vertically integrated electric utilities may also be sellers in the wholesale market, selling excess generation to third parties in order to reduce costs to their retail consumers. Independent power producers own generation in these regions and sell it in the bilateral market to the load serving entities. Some of the generation owned and operated in non-RTO regions is wheeled to the ISO/RTO markets and sold in those markets. Some of the load located in non-RTO regions is served with generation purchased from ISO/RTO markets and wheeled to consumers.

In both ISO/RTO regions and non-ISO/RTO regions, generation is largely dispatched on an economic basis. In the non-ISO/RTO regions, the generation is dispatched by the electric utilities that own the generation or by those with the contractual right to use it. In the ISO/RTO regions, the generation is dispatched based both on utilities' self-scheduling decisions and based on the outcome of the ISO/RTO's security constrained economic dispatch – essentially auctions.

In both ISO/RTO regions and non-ISO/RTO regions, there are exceptions to economic dispatch. Plants may be dispatched out of merit order if required to preserve reliability. For example, an expensive power plant in a region subject to transmission constraints may need be dispatched in lieu of a less expensive plant outside the constrained area in order to ensure enough power is available in the constrained area. A more expensive plant may need to be dispatched over a less expensive plant because the more expensive plant may be better located to be able to provide voltage support on a vulnerable portion of the grid. A more expensive plant may need to be dispatched over a less expensive plant because the more expensive plant can be ramped up and down more quickly in response to changing load, wind patterns or solar output in the region. A more expensive plant may need to be dispatched over a less expensive plant in the middle of the night because the more expensive plant will be needed the next day for an anticipated peak load the next morning and it cannot start up fast enough to meet that need if it is allowed to cool down over night.

For these purposes it is also important for the EPA to understand the regional and interregional nature of the electric system. The United States is broken into three different Interconnections with very little power exchanged between them: the Western Interconnect largely on the western side of the Rockies, which includes parts of Mexico and Canada; the Eastern Interconnect largely on the eastern side of the Rockies, which also includes parts of Canada; and ERCOT, which includes parts but not all of Texas. As mentioned, the United States is also divided up by those areas that are in the various RTOs or ISOs: the California ISO, ERCOT, the Southwest Power Pool (SPP), the Mid-Continent Independent System Operator (MISO), PJM, the NY Independent System Operator (NYISO), and the New England Independent System Operator (NEISO). Some States are not in any ISO or RTO. Some States have some load and some generation in an RTO or ISO and other load and generation outside any ISO or RTO. Some States are entirely in an ISO or RTO. And, some States have load and generation in two or even three ISOs or RTOs. In order to coordinate, the States in RTO's and ISOs are often members of loose organizations such as the Organization of MISO States or the Organization of PJM States.

The regional and interregional nature of the grid is also reflected in the location of generation assets and load. The load in most States is served by generation in many other States. Both fossil and CO_2-free generation is traded across state lines. In some cases, the States know exactly from which generators in which States they get some of their power (as a contractual matter) because the utilities in those States own or have long-term contracts for power from specific generation in other States. In every case, load in each State is served by at least some generation whose (contractual) source is completely unknown because that power is purchased out of a centralized market, is purchased from a third party who has purchased the generation from the centralized market or is purchased from a third party whose sources of power are confidential business information.

In every case, load is served from generation whose source is unknown as a matter of engineering, because power does not follow contractual paths but rather the laws of physics. This fact makes it very difficult or impossible to know how one resource that may be dispatched out of merit order will displace another. If wind ramps up in a region, a lot of power plants relying on different fuel sources may be ramped down. Which generation sources are more likely to be ramped down in response to that increase in wind will depend on the region, the season, the time of day, and the comparative price of fuels at that point in time. If consumers implement more energy efficiency measures, it is similarly impossible to know as a matter of contract or as a matter of engineering exactly which resources will ramp down in response. It is as if every hose in a neighborhood is used to fill up a pool. If someone jumps into the pool and splashes some water out, whose water was displaced?

b. Limited state jurisdiction over energy industry

In light of the complicated nature of the grid and the industry and its regional and interregional nature, it is no wonder that Congress concluded in the Federal Power Act that "the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to . . . that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest."[130]

The Federal Power Act does reserve some areas of regulation to the States. States regulate electric distribution – at least to the extent those same facilities are not used for transmission of power in interstate commerce. States regulate the rates, terms, and conditions of retail electric service for most consumers. And States have some jurisdiction over the siting and construction of new power plants and new transmission infrastructure built in the State. For example, an entity interested in building a power plant may be required to obtain a certificate of public convenience and necessity (CPCN) from the State in which it seeks to build. A CPCN usually requires a state determination that construction of a new power plant of the type and size proposed is consistent with the "public interest." Once a plant obtains a CPCN and begins operating, the State's role generally is limited to environmental oversight and recovery of costs associated with the plant through retail rate regulation. In general, the authority to grant a CPCN does not necessarily give a State the authority to revoke that CPCN once granted because the plant uses a disfavored fuel or to require the generator to operate less than provided for in the original certificate. Nor does a State have the specific authority to require construction of generation or transmission assets.

Some States do have authority over resource choices made by some generators within their borders. In traditionally regulated States, where state-jurisdictional vertically integrated utilities serve electric load

[130] FPA Sec. 201.

in the state, the state Public Utility Commissions generally have the authority to review and guide the regulated utility's integrated resource plans (IRPs). These are the utilities' plans for meeting forecasted annual peak and energy demand, plus some established reserve margin, through a combination of supply-side and demand-side resources and infrastructure development over a specified future time period. Utilities develop an IRP by evaluating their future supply needs and then assessing which resources and infrastructure best serve their needs in the most economic manner. This assessment considers factors like supply costs, reliability, and environmental concerns. Most States require utilities to file their IRPs regularly with the public utility commission. These plans help to guide a utility's long-term power supply decisions. States may thus have some going-forward – but not retroactive – authority to guide the resource choices made by the utilities they regulate. It must be recognized, however, that state law governs the criteria that PUCs are required to use in judging resource plans, and environmental laws are only one of those criteria. PUCs must balance all of the statutorily defined state interests and cannot direct a particular resource portfolio based solely on the desire to control a single pollutant. And, under the regulatory compact, they cannot deny cost recovery for prudent investments made in the past that are still used and useful.

c. Limits of utility authority

In restructured States, PUCs no longer have the authority to regulate the resource choices made by most utilities. They have ceded those decisions to the best judgment of the competitive energy suppliers. They cannot direct those competitive suppliers to use more or less of any fuel or to rely more or less on any particular source or sources of power. In both traditionally regulated States and restructured States, PUCs lack the authority to regulate resource decisions made by independent power producers. These competitive wholesale generators do not sell at retail and thus are not subject to state rate or IRP regulation. They sell at wholesale at rates, terms, and conditions regulated by the Federal Energy Regulatory Commission. They make their own resource investment decisions based on their estimate of the market value of those decisions.

It is true that some States – with both traditional and restructured retail markets – have established Renewable Portfolio Standards (RPSs). Mostly enacted by state legislatures rather than PUCs (but not exclusively), those States require utilities to serve retail load with certain levels of renewable generation by certain deadlines.[131] State PUCs may implement and enforce the RPSs, but the levels of renewable generation required, the types of resources from which utilities must obtain power, and the other key terms of the RPSs are largely the creature of the State and not the agency. These RPSs differ dramatically across the country, reflecting very different judgments in different States about the available resources, their costs and benefits to consumers, and the States' appetite to spend consumers' money to support those resources.

The same is true with respect to energy efficiency mandates. Most such mandates are creatures of state law, not unilateral regulatory action. Those mandates differ substantially from state to state, reflecting different judgments about the costs and benefits of energy efficiency, the best ways to pursue efficiency, and the States' relative appetites for spending money on efficiency.

Once generation is built, traditionally regulated States have very limited authority to govern how that generation is dispatched and used to serve consumers by jurisdictional utilities. As economic regulators, PUCs review jurisdictional utility costs to ensure that those costs were incurred prudently. Thus, the PUCs can look to see how a utility chose to dispatch its own units and when it chose to purchase from third parties instead of operating its own generation. But, under state law, a PUC's purpose in that review is not to ensure that the utilities have minimized the emissions of a single pollutant. By law, they are looking at the prudence of the utility's activities, which is mostly focused on minimizing cost and financial risk to retail consumers.

In restructured States, utility commissions lack even this limited authority over competitive suppliers. Because the PUCs are economic regulators – protecting retail consumers from excessive rates – prudence review of utility activities is assumed to be unnecessary because the State has chosen to rely on competitive pressures to keep rates just and reasonable. In both traditionally regulated and restructured

[131] *See, e.g.*, West Cal. Pub. Util. Code § 399.11 (2014).

states, PUCs lack any authority over the dispatch decisions of Independent Power Producers. Those decisions, made for wholesale sales, are subject to FERC jurisdiction if they are regulated at all.

In sum, States do have some limited authority to shape the mix of generation built within their borders used to serve retail load. States do not, however, control the day-to-day dispatch of power plants or utility systems, once they are built.

d. Expansive and exclusive FERC Jurisdiction

The Federal Power Act (FPA) gives the Federal Energy Regulatory Commission (FERC) *exclusive* jurisdiction to regulate wholesale sales of electricity and the transmission of electricity in interstate commerce. 16 U.S.C. § 824.[132] The Proposed Rule contemplates that States will direct utilities to substitute the use of higher emitting CO_2 generators with lower- or zero-emitting generators, through some combination of shifting from coal-fired units to increased dependence on gas generation, renewables and/or demand response. EPA's purported "best" system of emissions reduction "beyond-the-fence" incorrectly assumes that States can regulate activities that are subject to FERC's jurisdiction or are otherwise beyond their authority.

The FPA vests FERC with authority to ensure that the rates, terms, and conditions for jurisdictional sales and transmission are "just and reasonable" and "not unduly discriminatory" or preferential. Phrased differently, rates, terms and conditions *cannot be* "unjust or unreasonable" and *cannot be* "unduly discriminatory or preferential." All jurisdictional wholesale sales of electricity and transmission services must, by law, be provided pursuant to FERC approved tariffs. 16 U.S.C. § 824d. The rates, terms and conditions established in these tariffs are FERC-approved filed "rates," subject to the "Filed Rate Doctrine" (as described below).

In practice, for much of the country, FERC approved "rates" for wholesale electricity sales and transmission service are the tariffs approved for Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs). ISOs and RTOs are FERC-approved organizations that: (1) have

[132] The FPA defines "wholesale sales" as any sale of electricity for resale and "interstate transmission" as the transmission of electricity from one State to another. 16 U.S.C. §§ 824(c)-(d).

organized markets for sales of electricity in a set geographic area, and (2) operate the transmission grid in that area. Generally, these markets work by evaluating the demand for electricity and available supply, and then by applying a series of rules to select the generation with the "least-cost" to meet demand using a form of "security constrained economic dispatch."[133] For entities that do not participate in an RTO, rates, terms, and conditions of wholesale sales of electricity and the dispatch of generation facilities may be implemented though (and reflected in), among other things, power sales contracts, "pooling agreements," or reserve sharing agreements. In each of these arrangements, parties agree to sell, pool, or share their generation resources to serve their respective loads and to maintain reliability. For purposes of the Proposed Rule, however, the important point is not what rates and terms are in the tariffs governing the different power markets; rather, the important point is that *all of these terms and conditions are filed with and approved by FERC and FERC alone*. *Neither EPA nor the States have any power to alter them*. Further, under the Filed Rate Doctrine, operators are bound to what FERC has approved and have no choice but to implement the rates, terms, and conditions of their FERC tariffs

FERC is not an environmental regulator. FERC has never implemented an environmental dispatch under the Federal Power Act or its regulations. FERC has ensured that variable renewable generation – largely wind – can participate effectively in the wholesale markets without undue discrimination.[134] It has not, however, ever required a generation dispatch preference for resources based on their emissions characteristics, or given a preference to certain types of generation resources for purposes of setting wholesale power sales rates or regulating transmission service.

e. Supremacy Clause limitations on state action related to FERC-regulated activities.

EPA in the Proposed Rule requires States to go "beyond the fence line" to restructure the manner in which generation (and generation portfolios) are dispatched and curtailed, rather than regulating the

---

[133] Section 1234(b) of the Energy Policy Act of 2005 defined security constrained economic dispatch as "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities." *See* Joint Boards on Security Constrained Economic Dispatch, 112 FERC ¶ 61,353 at P14 (2005).
[134] *See e.g.*, Integration of Variable Energy Resources, 77 Fed. Reg. 41,482 (FERC 2012).

emissions rate of specific generation resources. As discussed above, however, States do not have this authority. Even in those States where PUCs retain authority to regulate retail utilities, the PUCs are limited to reviewing the prudence of utility investment and operational decisions. State legislatures are also free to direct retail utilities in the State to generate or purchase power from specified resources. That is a far cry, however, from the authority the EPA seems to assume States have to redirect the dispatch of generation, most of which takes place in the wholesale market subject to FERC's exclusive jurisdiction.

The Supreme Court has consistently held that States may not infringe on FERC's exclusive authority over wholesale sales and markets, explaining that:

> Congress has drawn a bright line between state and federal authority in the setting of wholesale rates and in the regulation of agreements that affect wholesale rates. States may not regulate in areas where FERC has properly exercised its jurisdiction to determine just and reasonable wholesale rates or to insure that agreements affecting wholesale rates are reasonable.[135]

Thus, any state action that EPA includes in its redefinition of BSER that directly or indirectly modifies the way that electricity is sold at wholesale or transmitted in interstate commerce could impermissibly intrude on FERC's exclusive jurisdiction and is inconsistent with the Supremacy Clause of the Constitution.[136]

As explained above, the rates, terms, and conditions of power sales and service provided in FERC-regulated wholesale markets (both ISO/RTO and non-ISO/RTO) constitute FERC-approved tariffs. The "Filed Rate Doctrine" provides that a utility must strictly adhere to the rates, terms, and conditions for service that were filed with and approved by FERC.[137] Under the Filed Rate Doctrine, only rates that have been fixed or accepted by FERC may be charged; not even the state or federal courts can authorize a utility to charge a different rate.[138] Therefore, any attempt by the States to force specific utilities and/or generators to depart from the dispatch and curtailment provisions in their FERC-approved tariffs and service

---

[135] *Mississippi Power & Light Co. v. Mississippi*, 487 U.S. 354, 374 (1988).
[136] *Id*. at 377 ("Consequently, a state agency's 'efforts to regulate commerce must fall when they conflict with or interfere with federal authority over the same activity.'" *Chicago & North Western Transp. Co. v. Kalo Brick & Tile Co*., 450 U.S. 311, 318-319 (1981).").
[137] *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 963 (1986).
[138] *Id.* at 963.

agreements to comply with a State-mandated environmental dispatch will be an impermissible intrusion on FERC's authority.

In *Mississippi Power & Light Co. v. Mississippi*, the Supreme Court declared unlawful the Mississippi Public Service Commission rejection of the inclusion of nuclear power plant construction costs in the retail rate sought by Mississippi Power & Light. The Court overturned the PSC decision because FERC had approved a contract under which the utility was to purchase a percentage of the plant's output at amounts and rates FERC had determined to be just and reasonable. Following *Nantahala*,[139] the Court concluded that: (1) FERC has exclusive jurisdiction over wholesale rates, and utilities cannot be ordered to charge rates not on file with FERC; (2) "FERC's exclusive jurisdiction applies not only to rates but also to capacity allocations that affect wholesale rates"; and (3) States may not bar regulated utilities from passing through to retail customers FERC-mandated wholesale rates.[140] It thus would follow that, under the Proposed Rule, a State could not use its economic regulatory authority to block purchases of power from higher-emitting resources where contracts for the purchase of that power had already been approved by FERC.

States might also have trouble directing utilities to invest in lower emitting resources where those investments could hurt the investment interests of independent owners of higher-emitting resources in FERC-jurisdictional wholesale markets. In *New England Power Generators Association, Inc. v. FERC*, the D.C. Circuit held that FERC could lawfully approve a tariff for the ISO-NE market that would have had the effect of significantly burdening state RPSs.[141] Under the ISO-NE tariff approved by FERC, utilities that invested in renewable resources in compliance with state RPS requirements could not use the capacity from those resources to demonstrate that they had enough capacity to meet their consumers' demand unless those resources were bid into and cleared in the ISO-NE capacity market. Because the new renewable resources cost significantly more than the already depreciated fossil resources in that market, it was highly unlikely

[139] *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 963 (1986).
[140] *Id.* at 371.
[141] 757 F.3d 283 (D.C. Cir. 2014).

they would clear. The utilities, therefore, could not only have to pay for the renewable resources to meet their RPS requirement but also pay for duplicate capacity in the market.

The Fourth Circuit's decision in *PPL EnergyPlus, LLC v. Douglas R.M. Nazarian*[142] upheld a district court order striking down a Maryland law that directed state jurisdictional retail utilities to contract with a select generator to purchase the generator's output at a specified price to encourage new gas-fired generation in the State.[143] In this case, the State was addressing concerns that insufficient generation was available to meet local needs, but it could have equally been designed to ensure that new lower-emitting resources would be built to replace existing higher-emitting resources pursuant to the Proposed Rule. The court concluded that the laws interfered with wholesale ratemaking because the new capacity would "affect" prices for capacity in a FERC-regulated market. The Fourth Circuit stated:

> Although states plainly retain substantial latitude in directly regulating generation facilities, they may not exercise this authority in a way that impinges on FERC's exclusive power to specify wholesale rates. As the Supreme Court noted in a similar context:
>
> [T]he problem of this case is not as to the existence or even the scope of a State's power to [regulate generation facilities]; the problem is only whether the Constitution sanctions the particular means chosen by [the state] to exercise the conceded power if those means threaten effectuation of the federal regulatory scheme.[144]

In this regard, the Fourth Circuit found that Maryland law impermissibly eroded the FERC-determined price and undermined FERC's exclusive authority. Thus, state actions that undermine a FERC tariff could be found to violate the Supremacy Clause, even if undertaken to advance a permissible state objective, including attempts to comply with the Proposed Rule.

The environmental dispatch of generation that would be required under the Proposed Rule could be found beyond the States' authority to implement, because FERC—not the States—establishes the rules governing how generation is dispatched in wholesale markets. Any attempt by the States to impose

[142] 753 F.3d 467 (4th Cir. 2014).
[143] In addition to the Fourth Circuit decision regarding the Maryland program, a district court in New Jersey struck down a similar New Jersey law last year with a "Contract for Differences" scheme. *PPL EnergyPlus, LLC v. Hanna*, 977 F. Supp. 2d 372 (D.N.J. 2013). The Third Circuit upheld the district court decision on appeal. *PPL EnergyPlus, LLC v. Solomon*, No. 13-4330 (3d Cir. Sept. 11, 2014).
[144] *Id.* at 477 (quoting *N. Natural Gas Co.*, 372 U.S. at 93).

requirements contrary to FERC approved tariff and market rules could be found to violate the Supremacy Clause of the Constitution.

2. Regional power markets may not be prepared to implement an environmental dispatch obligation.

EPA's proposed environmental dispatch scheme proposes to switch the order (and roles) of coal-fired and gas-fired generation in utilities' generation dispatch, as supplemented by renewables and demand-side management. EPA should not simply assume (as it has done in its Proposed Rule) that the power industry is prepared to implement this shift while maintaining reliability. The implementation of EPA's proposed environmental dispatch scheme appears to be premised on assumptions about the existence of infrastructure, market forces, and market incentives that either are not correct or cannot be effectively implemented to accommodate mandatory environmental dispatch without compromising electric reliability.

i. Market Redesign

An example of the challenges, substantial uncertainties, and time involved is useful here. Imagine State X in the Midwest chooses to implement the Proposed Rule by pursuing environmental re-dispatch of generation in its own State, only a portion of which is used to serve retail load in the State. It could try by legislation to impose command and control limits on the dispatch of certain high-emitting generation in the State (the PUC would have no such authority). That, however, could be litigated and found to constitute a taking and would thus require the owner of the generation to be compensated for the lost revenue.

The State could seek unilaterally to impose a CO_2 tax on the generation in the State in an effort to decrease the economic dispatch of that generation. Those resources in the State affected by the tax, particularly those whose output is sold outside the state might well have an effective basis for a Commerce Clause challenge because the state is harming interstate commerce.[145] Even if that Commerce Clause challenge loses, there may well be a successful pre-emption challenge under the theories discussed above:

[145] *See North Dakota, State of et al. v. Swanson et al.*, No. 0:11-cv-03232 (D. Minn. April 18, 2014) (enjoining Minnesota from enforcing sections of the Next Generation Energy Act restricting electricity imports from new power plants that increase greenhouse gases).

by implementing a CO_2 tax with the intent of affecting wholesale prices in the FERC-jurisdictional MISO market, for the purposes of changing the dispatch order of resources in that FERC-jurisdictional MISO market, the State could be found to have interfered with FERC's exclusive jurisdiction over those prices. This would leave State X the option of pursuing a change to the MISO tariff in order to implement an environmental dispatch. Such tariff changes would have to be negotiated through the MISO stakeholder process, approved by the MISO board, approved by FERC, and ratified by the courts after the inevitable challenge to FERC's order, no matter how FERC rules in the case. State X would have to obtain consensus or near consensus among all of the 12 States served by MISO, the state-regulated utilities served by MISO, the independent power producers and the transmission owners and operators. All of these entities have different interests that would be affected by the move to environmental dispatch. While the owners of low-emitting resources would likely be big supporters, the owners of higher-emitting resources would object, the consumer advocates would object to the higher prices that would come from environmental dispatch, and several States that were host to higher-emitting sources or that were focused on the affordability of power would object. Environmental re-dispatch would also change the flow of power on the grid. It could create new areas of congestion, creating higher prices and reliability risks for some consumers, leading them and their representatives in state government to object. Only after some settlement has been reached among all of these parties, which might require substantial compromise from the original vision aimed at Proposed Rule compliance, would a tariff be likely to be filed at FERC.

At that point, FERC would have to struggle with a question of first impression: does its responsibility to ensure that rates are just and reasonable and not unduly discriminatory permit it to approve an environmental re-dispatch tariff that increases rates above those that would be available under an economic dispatch, a tariff that expressly discriminates against certain resources based on their emissions of CO_2. After FERC reaches its conclusion, that question would then have to be readdressed by at least one court of appeals. This is a very slow process, one that creates significant uncertainty for the entire industry.

ii. Preservation of Reliability

Section 215 of the Federal Power Act authorizes FERC to oversee the reliable operation of the Nation's interconnected electrical bulk power system.[146] In 2007, FERC approved mandatory national reliability standards for administration by the North American Electric Reliability Corporation (NERC).[147] The national standards apply to entities that own, operate, and/or use operating generation or transmission facilities as part of the interconnected transmission bulk power system. As owners and operators of generation and transmission facilities, utilities are subject to many of these reliability standards. Under the national standards, utilities and the operators of utility assets must respond to emergencies within stated time periods, maintain prescribed levels of generation reserves, protect equipment from sabotage, and follow instructions concerning load shedding.

FERC's jurisdiction over the nationwide interconnected electrical bulk power system means that FERC has a crucial role to play in ensuring that environmental regulation does not impair or impede grid reliability. FERC Commissioner Moeller has repeatedly expressed concern that, unless environmental regulations are carefully implemented and coordinated with FERC, the nation's power grid may struggle to maintain reliability, especially during extreme weather conditions:

> While nobody can guarantee future reliability, we can do better in understanding the risks and issues facing the power grid in the future. As the history of my testimony before Congress demonstrates, the sufficiency of our generating resources has been clouded by uncertainties arising from changing environmental regulation. While we have been sensitive to the fragility of our electric infrastructure in certain pockets of the country, this winter has demonstrated that our margin of surplus generation is narrower and more constrained than many understood.[148]

Despite FERC's unique and well-established role in maintaining grid reliability, there has been a troublesome lack of coordination between FERC and EPA regarding this proposal. FERC's Office of

---

[146] 16 U.S.C. § 824o.

[147] *Mandatory Reliability Standards for the Bulk Power System*, Order No. 693, 72 Fed. Reg. 16,416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242, P 492 (2007) ("The Commission notes that it has jurisdiction under Section 215 of the FPA over all users, owners and operators of the Bulk-Power System to ensure Reliable Operation of the Bulk-Power System."), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[148] Testimony of Philip D. Moeller, Commissioner, Federal Energy Regulatory Commission, Before the Hearing of the U.S. Senate Committee on Energy and Natural Resources: "Keeping the Lights on – Are We Doing Enough to Ensure the Reliability and Security of the U.S. Electric Grid?" at 3 (April 10, 2014).

Electric Reliability has specific expertise on power grid reliability and was formed in response to the 2003 Northeast blackout under new authorities granted to FERC by Congress in the Energy Policy Act of 2005. One of the office's major responsibilities is to "coordinate with the applicable federal agencies … to facilitate energy reliability and security." As recognized by the EPA, the Proposed Rule's proposed environmental dispatch must be implemented in manner that preserves reliability.[149] Yet EPA has failed to address how exactly it will require or enforce environmental dispatch in light of the fact that FERC has primary and exclusive jurisdiction over reliability standards.[150] In failing even to request written feedback from FERC regarding potential reliability issues resulting from the Proposed Rule, the EPA has left its best resource for resolving these issues untapped.[151] NRECA cannot comment at this time on the specific scope and nature of reliability concerns that may be implicated by a shift towards environmental re-dispatch, because such reliability concerns will vary depending on the specific utility and the type of dispatch implemented. NRECA, however, does not believe that the Proposed Rule fully contemplates several issues that *must* be addressed before any environmental dispatch regime can be implemented reliably.

The need for careful analysis and coordination is especially important in light of the conclusions reached by the Southwest Power Pool (SPP) and NERC in their preliminary evaluations of the reliability impacts of the Proposed Rule. As discussed in more detail below, both organizations have significant concerns that the Proposed Rule as drafted could pose a threat to the reliability of the electric power grid.

---

[149] Environmental Protection Agency, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Proposed Rule, 79 Fed. Reg. 34,829, 34,899 (June 18, 2014) ("Many stakeholders raised concerns that this regulation could affect the reliability of the electric power system. The EPA agrees that reliability must be maintained and in designing this proposed rulemaking has paid careful attention to this issue.").

[150] *See, e.g.* Written Testimony of Commissioner Phillip D. Moeller Before The House Committee on Energy and Commerce Subcommittee on Energy and Power, United States House of Representatives, Hearing on FERC Perspective: Questions Concerning EPA's Proposed Clean Power Plan and other Grid Reliability Challenges at 7 (July 29, 2014) ("Moeller House Testimony") ("Just as the Commission does not have expertise in regulating air emissions, I would not expect the EPA to have expertise on the intricacies of electric markets and the reliability implications of transforming the electric generation sector. Hence I reiterate my call for a forum to publicly discuss the extent of reliability challenges under the proposal and potential solutions to these challenges. The EPA's plan is not the Commission's rule but rather proposed by the EPA, so the responsibility to formally address the reliability implications should be promoted by the EPA with extensive Commission involvement. Any such process must be open and transparent, and cannot be merely a private and paperless discussion between government employees.").

[151] *See* FERC Perspectives: Questions Concerning EPA's Proposed Clean Power Plan and Other Grid Reliability Challenges, House of Representatives, Subcommittee on Energy and Power, 113th Cong., 39–40 (July 29, 2014) (Testimony of C. Lafleur), *available at* http://docs.house.gov/meetings/IF/IF03/20140729/102558/HHRG-113-IF03-Transcript-20140729.pdf.

iii. Increased use of natural gas-fired generation

EPA cannot simply assume the availability (or planned future availability) of sufficient natural gas generation, natural gas pipeline capacity, or natural gas storage to support EPA's proposed environmental dispatch, particularly in ISO/RTO markets. Indeed, the recent Polar Vortex revealed that heavy reliance on the dispatch of natural gas fired generation already pushes the system to its limits without the additional demand that the Proposed Rule would require utilities to put on the system.[152]

The availability of gas-fired generation depends on the availability of natural gas transportation to the individual unit and, especially during periods of high gas demand, the availability of sufficient high-capacity gas storage close to the location of gas withdrawal. Yet, firm transportation service is not always available in the winter (the highest period of demand for gas heating), and purchasing firm transportation service for gas is often not economically feasible when that service is really only needed those few hours a year when extreme weather events like the Polar Vortex create high demand for both electricity and end-use natural gas. Moreover, as several cooperatives discovered during the Polar Vortex, even having contracted for firm gas and firm gas transportation was no guarantee that gas would be available and deliverable during periods of such high demand. When the nationwide gas transportation system is constrained by peak demand during periods of extremely cold weather, gas-fired generators have sometimes been "unable to procure sufficient resources to fulfill their electricity market commitments and to contribute to reliable system operation."[153] For example, during last winter's Polar Vortex, natural gas

[152] Moeller House Testimony at 7-8; *see also* FERC Staff Presentation, "Recent Weather Impacts on the Bulk Power System" at 16 (Jan. 16, 2014), *available at* http://www.ferc.gov/CalendarFiles/20140116102908-A-4-Presentation.pdf ("FERC Polar Vortex Presentation") ("U.S. gas demand hit 137 Bcfd on Tuesday January 7, 11 Bcfd over the previous winter record set in the winter of 2008/9. Demand records were breached in the Midwest, the Northeast, and the Southeast, which added to constraints on pipelines delivering gas to the Mid-Atlantic and Northeast. Consequently, natural gas prices averaged over $70/MMBtu along the I-95 corridor, between Richmond and New Jersey, with some intraday trades close to $100/MMBtu...Well freeze-offs in some major producing basins reduced natural gas supply, just as demand was peaking."). *See* Assessment of the Impact of the EPA's Proposed 111(d) Targets on Natural Gas Demands by State, NERA Report for NRECA, Attachment G, at 15.

[153] *Order Initiating Investigation Into ISO and RTO Scheduling Practices and Establishing Paper Hearing Procedures*, 146 FERC ¶ 61,202 at P 5, P 16 (Mar. 20, 2014) ("FERC Scheduling Coordination Order") ("Several events over the last few years, such as the Southwest Cold Weather Event in February 2011, and the recent extreme and sustained cold weather events in the eastern US in January 2014, show the crucial interconnection between natural gas pipelines and electric transmission operators and underscore the need for improvements in the coordination of

distribution companies in the Northeast and Midwest were forced to ask non-essential customers to voluntarily curtail gas use.[154] Some cooperatives with firm service found even that service curtailed and others found that no gas was available at any price. For instance, during the Polar Vortex, Hoosier Energy's Holland Energy facility experienced periods of extreme natural gas prices based on elevated demand and pipeline outages. These physical limitations, combined with differences in the operational structure of the natural gas and electricity markets, made it extremely difficult to obtain fuel and run the facility. As a result the plant only ran four days from the period January 1, 2014 through March 31, 2014. Based on produced versus potential MWhs, the facility had a capacity factor of 1%. The NERC report Potential Reliability Impacts of EPA's Proposed Clean Power Plan explains, "As gas-electric dependency significantly increases, unforeseen events like the 2014 polar vortex could disrupt natural gas supply and delivery for the power sector in high-congestion regions, increasing the risk for potential blackouts."

FERC has recognized that, as our Nation's dependence on natural gas generation continues to rise, the differences between regionally coordinated electricity market scheduling timelines and the nationwide gas scheduling timeline are increasingly likely to impede reliability across the electric grid.[155]

FERC has promulgated a rulemaking to investigate mechanisms to facilitate the use of increased amounts of gas generation to serve load.[156] The rulemaking responds to the concerns of ISOs and RTOs about the potential reliability effects on their systems should gas-fired generators have trouble acquiring natural gas or experience curtailment of natural gas supplies, particularly during periods of extreme weather

---

natural gas and electricity markets."); *see also* FERC Polar Vortex Presentation at 4 ("At this time, it appears that Midwest, Northeast, and Southeast regions set record demands for natural gas, while other parts of the Eastern and Central U.S. were near their all-time peaks. One compressor station outage on the Texas Eastern pipeline in Western Pennsylvania resulted in throughput reductions of nearly 600,000 decatherms per day, or about ten percent of the pipeline load. Most other pipelines curtailed interruptible or secondary firm transportation and storage services.").

[154] FERC Polar Vortex Presentation at 16.

[155] FERC Scheduling Coordination Order at PP 5-6.

[156] FERC Scheduling Coordination Order at P 7 (Mar. 20, 2014) ("ISOs and RTOs expressed concern about the potential reliability effects on their systems if gas-fired generators encounter difficulty in acquiring natural gas or are subject to curtailment of natural gas supplies, particularly during periods of high demand on both the interstate pipeline and electric transmission systems. Interstate pipelines expressed similar concern about the effect on their ability to deliver natural gas when electric generators are dispatched and need to burn more natural gas than they have nominated.").

and high demand.[157] Entities overseeing interstate natural gas pipelines have expressed similar concerns regarding their ability to deliver natural gas when electric generators are dispatched and need to burn more natural gas than they have nominated.[158] FERC has determined that generators need the flexibility of the gas scheduling system to improve in order to accommodate their need to revise nominations in response to weather events or other operational needs.[159] Thus, there is concern (both within FERC and in the industry) that steps must be taken to ensure that ever-increasing amounts of gas generation can be used to serve load reliably.

The Proposed Rule also assumes that the necessary gas distribution infrastructure exists (or is planned to be built) to support increased reliance on gas generation. This may be true in certain parts of the country, but not others. Gas pipeline developers are reluctant to build pipelines without “anchor” customers, which would generally be the natural gas generation owners that use the gas.[160] These generation owners, however, will not commit to the long-term contracts that are necessary to serve as sufficient anchor customers unless they know how they will be dispatched in the long-term.[161] These gas facilities do not currently know how they will be dispatched in today’s market, and they do not know how they will be relied upon under the environmental dispatch proposed by EPA.[162] This dilemma is only complicated further if the generators are in organized markets that serve multiple States because, under the Proposed Rule, the generator may be dispatched at different levels (and require different levels of fuel) depending on the

[157] FERC Scheduling Coordination Order at P 7.
[158] *Id.* Three things make managing fuel procurement and price risks challenging for generators and transmission operators: (1) the difference in operating days used by the natural gas and electric industries; (2) the fact that the timeframe for nominating natural gas pipeline transportation service is not synchronized with the timeframe during which generators receive confirmation of their bids in the day-ahead electric markets; and (3) the fact that it is not economic for electric generators to pay for firm pipeline capacity.
[159] FERC’s rulemaking is designed to address specific areas in which the differences between the nationwide natural gas schedule and regional electric schedules hinder reliability and create scheduling inefficiencies that result in less cost effective use of resources. These issues include: 1) the discontinuity between the operating days of electric utilities (including ISOs and RTOs) and the standardized operating day of interstate natural gas pipelines; 2) the lack of coordination between the day-ahead process for nominating interstate natural gas pipeline transportation services and the day-ahead process for scheduling electric generators, particularly those of the ISOs and RTOs; and 3) the lack of intraday nomination opportunities on interstate natural gas pipelines, which may limit the ability of gas-fired electric generators, as well as other shippers, to revise their nominations during the operating day. Id at 26
[160] Moeller House Testimony at 4.
[161] *Id.*
[162] *Id.* at 3-4.

location of the load they may be designated to serve and that State's specific environmental dispatch requirements.[163] Thus, the Proposed Rule may actually be disincentivizing the development of the natural gas infrastructure that EPA assumes exists.

iv. Renewable generation

The environmental dispatch required by the Proposed Rule will increase reliance on renewable generation. Over the last several years, FERC has implemented several rules meant to better interconnect and integrate the dispatch, scheduling and support (through ancillary services) of renewable generation into the bulk power system.[164] These efforts are still ongoing at different stages around the country.

NRECA will not attempt to identify all of the different operational and commercial issues that will need to be resolved in order to rely more heavily on renewables in the Proposed Rule's proposed environmental dispatch. The point is that, while FERC has made significant steps towards the integration of renewables, those efforts are in their preliminary stages, partially because of their potential to impact reliability. As stated above, States cannot lawfully implement an environmental dispatch that conflicts with FERC tariffs, whether they relate to organized markets or any other FERC-jurisdictional service. Therefore, it is FERC, and not the States, that must control how renewable resources may be used to implement the environmental dispatch that the Proposed Rule contemplates.

v. Impact of first-in-time priority access to transmission capacity established by FERC's open access policies

The Proposed Rule's environmental dispatch is also likely inconsistent with a long list of provisions in FERC's Open Access Transmission Tariff (OATT) defining transmission customers' transmission rights, including the priorities different customers have for access to the transmission system. For example, the OATT provides "first-in-time" priority to transmission capacity for generation resources

[163] *Id.* at 2 ("The biggest challenge in implementing the proposed rule is that electricity markets are interstate in nature. Thus the proposal's state-by-state approach results in an enforcement regime that would be awkward at best, and potentially very inefficient and expensive.").

[164] For example, FERC has amended its pro forma Open Access Transmission Tariff to require transmission providers to offer intra-hourly transmission scheduling to accommodate variable energy resources, but issues remain regarding generator regulation services for variable sources. Integration of Variable Energy Resources, FERC Order No. 764, 139 FERC ¶ 61,246 at PP 1-4 (2012).

that qualify as "Designated Network Resources" under FERC's pro forma OATT. Under this policy, priority to transmission capacity used for "long-term firm transmission service" over the bulk transmission system is assigned transmission customers based on a standard that allocates transmission capacity to users (including utilities seeking to serve their own native load) based on a "first-in-time principle." This first-in-time principle applies regardless of the fuel-source of any generation that may be competing for access to the transmission system. Therefore, under this standard, a transmission customer using transmission capacity for purposes of delivering power from a coal-fired generation unit has priority access to transmission capacity over the incumbent utility that may want the same transmission capacity to serve native load with renewable generation as long as the transmission customer requested transmission service first. A utility cannot reserve transmission capacity for future but currently "undesignated" network resources to the detriment to a transmission customers' prior-queued request for transmission service.[165]

Depending on whether and when transmission capacity was requested for purposes of a generation resource, the Proposed Rule's proposed environmental dispatch proposal to shift the use of natural gas and renewable generation to a different dispatch priority may interfere with the way that transmission capacity has traditionally been reserved by parties under FERC's open access policies. Section 217 of the FPA, added by Congress in 2005, expressly recognizes and protects utilities' right to maintain and use their rights to the transmission system. Thus, it would be very difficult for FERC to reallocate transmission rights to implement an environmental dispatch in non-ISO/RTO areas even if it wanted to. Even assuming that FERC implemented an environmental generation dispatch, many utilities may not have enough capacity on their transmission systems to support natural gas or renewable generators. Because this capacity may sit with other transmission customers under FERC's open access policies, this may require significant transmission expansion at significant cost. The Proposed Rule does not consider these possibilities and either the associated costs or time required to develop the new transmission.

[165] *Aquila Power Corp. v. Entergy Serv., Inc.*, 90 FERC ¶ 61,260 at 61,859 (2000), *order on reh'g*, 92 FERC ¶ 61,064 (2000), *order on reh'g*, 101 FERC ¶ 61,328, *reh'g denied*, *Entergy Servs., Inc. v. FERC*, 375 F.3d 1204 (D.C. Cir. 2004); *Morgan Stanley Capital Group v. Illinois Power Co.*, 83 FERC ¶ 61,204, at 61,911-12 (1998), *order on reh'g*, 93 FERC ¶ 61,081 (2000); *Wisconsin Public Power Inc. Sys. v., Wisconsin Public Service Corp.*, 83 FERC ¶ 61,198, 61-857-61,858 (1998), *order on reh'g*, 84 FERC ¶ 61,120 (1998).

B. The Proposed Rule violates the CAA and the Administrative Procedures Act because the Building Blocks on which the Proposed Rule's targets are based cannot generate the reductions EPA claims.

EPA's Building Block assumptions regarding legal applicability, technical capability, and related factual assumptions are unfounded, inexpert, and arbitrary – making the various Building Blocks fatally flawed, individually and in combination. As a consequence, the target emission rates EPA has proposed cannot possibly be achieved.

A core assumption of the Proposed Rule is that a State that fails to achieve targeted emission reductions in one Building Block will be able to achieve the overall emissions reductions goal by increasing the utilization of one or more of the other three. EPA thus makes no provision for adjusting any State's overall emission reduction target in the event that an assumption about a particular Building Block proves to be wrong. The record contains no support for this aspect of the Proposed Rule; in fact, the record militates against it. The ability of any State or regulated entity to avail itself of any particular Building Block to reduce emissions is limited, as EPA recognizes. By EPA's own admission, overall emission reductions from heat-rate improvements are limited to a maximum of about 6 percent.[166] Emission reductions from re-dispatch to NGCC units are necessarily limited by the lack of excess available capacity of such units in each State, as well as by lack of natural gas infrastructure in some States. Re-dispatch to renewables and nuclear is similarly limited. And emission reductions from end-user efficiency efforts are limited, again by EPA's own estimation, to approximately 1.5 percent per year. Requiring increases in the utilization of any of these Building Blocks in the face of these limitations is infeasible. The clear error in such a core assumption by itself requires a substantial reworking of this proposal.

1. Building Block 1: Heat Rate Improvements

a. The Proposed Heat Rate Improvement Requirements are not supported by the studies on which EPA relies

EPA's first Building Block – requiring heat rate improvements (HRI) at each designated coal-fired EGU – is unreasonable because EPA wrongly and inexpertly assumes that each coal-fired EGU in the fleet

[166] As discussed immediately below, we believe even this assumption is grossly overoptimistic, and in fact there may well be no notable heat rate improvement available for most of the coal-fired fleet.

can obtain a 4% to 6% HRI. EPA determined that this level of HRI can be achieved through heat rate variability reductions, best practices (BP), and equipment upgrades. Based on EPA's analysis of hourly data reported by regulated EGUs from 2002 to 2012, the Agency determined that 4% HRI can be achieved for the fleet of affected EGUs through adoption of heat rate variability best practices. It then determined that another 2% HRI can be achieved across the entire fleet through equipment upgrades. EPA relies on three studies to justify these conclusions: a 2009 Sargent & Lundy (S&L) heat rate study, a matrix analysis, and a sixteen-unit study.

As detailed below EPA has either misinterpreted these studies or has drawn arbitrary conclusions based on the studies' available data. Additionally, we include and discuss a recently-prepared report by S&L for NRECA which concludes that EPA misapplied the S&L 2009 study in this rulemaking; a critique of EPA's sixteen-unit study for the Utility Air Regulatory Group (UARG); and a separate study of nine cooperative coal-fired units that supports conclusions contrary to those made by EPA in the sixteen-unit study: that is, that the majority of heat rate reductions EPA has identified for the sixteen units are due to continuous emissions monitoring system (CEMS) changes in operation or calibration and are not related to actual heat rate reductions, contrary to EPA's conclusion.

b. The 2009 S&L Study's actual results and the NRECA S&L report identify EPA's flawed analysis and conclusions on HRI

EPA cites the 2009 S&L study to conclude that overall HRI in a range of 4 to 12 % is viable across the coal-fired EGU fleet, and within that range equipment upgrades can yield 2 to 4 % HRI across the fleet.[167] In determining this latter 2 to 4% HRI target attributable to equipment upgrades, EPA relies on a 2009 report by the engineering firm Sargent & Lundy. In a new report prepared for NRECA, Sargent & Lundy states that its 2009 study *did not* conclude that any individual coal-fired EGU, or any aggregation of such EGUs, can achieve the 6% HRI, as would be required by the Proposed Rule, or that 2 to 4% HRI can be achieved through equipment upgrades as this proposal presumes. According the S&L personnel who authored the 2009 report, that report was based on a literature survey, data provided by original equipment

[167] 79 Fed. Reg. at 34859-60.

manufacturers, and S&L's in-house database. Further S&L states in its report for NRECA that the HRI ranges described in the 2009 report were estimated *at a conceptual level only* and were not based on a detailed site-specific analysis. In fact, the case studies included in the 2009 report reveal that it is *not* feasible to apply all of the HRI alternatives that had been examined to every individual generating unit. These are critical technical details the EPA failed to consider when it evaluated the 2009 report in connection with this rulemaking. Its failure here is a fatal flaw.

To emphasize a fundamental finding in S&L's critique of EPA's use of its 2009 study, it is not possible to conclude that a 2 to 4% HRI through equipment upgrades is obtainable for any individual EGU or any aggregation of EGUs for a variety of reasons. The first is that individual generating units themselves vary in plant design, previous equipment upgrades, and operational approaches. The second is that individual HRI technologies and strategies do not always combine in ways that equal the sum of the parts. This is because many technologies affect and are dependent on interrelated variables of plant operation. In addition, the performance of some of the HRI strategies surveyed in the 2009 report will degrade over time, in spite of best maintenance practices. Finally, HRI depends on EGU load levels. A facility's average heat rate is lower when it is base-loaded than when it is load-cycled, resulting in less potential for achieving HRI. Thus, HRIs achieved at a specific unit by implementing the strategies discussed in the 2009 report could be negated if the unit shifts from being base-loaded to load-cycled. For these reasons, Sargent & Lundy believes that the only rational method for evaluating the technical feasibility and effectiveness of potential HRI projects is to conduct a unit-by-unit evaluation. Thus, EPA cannot reasonably rely on the 2009 S&L study to finalize any HRI targets without conducting a unit-by-unit analysis of all designated facilities to determine the extent to which HRI can be implemented at each.

We have included the S&L NRECA report, as Attachment B to these comments, detailing the specific information leading S&L to these conclusions. The general conclusions in the report are as follows:

- Sargent & Lundy's 2009 Report does not conclude that any individual coal-fired EGU or any aggregation of coal-fired EGUs can achieve 6% HRI (heat rate improvement) or any broad target, as assumed by the EPA.

- The results in the 2009 Report were mostly based on publicly available data, data from original equipment manufacturers, and Sargent & Lundy's power plant experience. Furthermore, the case studies showed that not all of the examined alternatives were feasible to apply to an individual generating unit due to a number of factors, including plant design, previous equipment upgrades, and each plant's operational restrictions.

- Various limitations exist for applying each heat rate improvement strategy, and these limitations depend on the unit type, fuel type, and many other site-specific conditions. Therefore, the ability to apply each strategy and the amount of heat rate reduction that can be achieved by each strategy is site-specific and must be evaluated on a case-by-case basis.

- It appears as though the EPA concluded that heat rate improvements cited in the 2009 Report were additive and applicable to all coal-fired units. Heat rate improvement ranges described in the 2009 Report case studies were estimated at a conceptual level, and were not based on detailed site-specific analyses. Verification of actual heat rate improvements was not made to determine whether any of the strategies were implemented and what actual heat rate improvements were realized based on site-specific design.

- Combinations of strategies to achieve heat rate improvements do not always provide heat rate improvement reductions equal to the sum of each individual strategy's heat rate improvement because many of the technologies affect, or are dependent upon, plant operating variables that are inter-related. Therefore, case-by-case analyses must be conducted to determine whether the incremental heat rate improvement through the application of multiple strategies is economically justified.

- The performance of some of the evaluated heat rate improvement strategies degrades over time, even with best maintenance practices. Therefore, depending on the strategy employed or the technology installed to reduce heat rate at an existing coal-fired EGU, the unit heat rate initially obtained may increase over time.

- Heat rate is increased when plants operate at lower loads, and the benefit of a heat rate improvement strategy is reduced at lower loads. Therefore, if an existing EGU is currently base-loaded and shifts to a load-cycling operating profile in the future, that unit's annual average heat rate will increase, and the heat rate reduction strategy (or strategies) implemented will not lower the annual average heat rate as much when compared to base-load operation. In some cases, any HRI improvements achieved by undertaking the relevant options described in S&L's 2009 Report could be negated by HRI losses associated with load-cycling.

- The installation of additional pollution controls such as those required by regulations including regional haze rules and MATS, will decrease the heat rate efficiency of any unit as compared to its heat rate efficiency before the installation.

- Many of the options for HRI listed in the 2009 Report have triggered New Source Review actions by EPA and others.

- Based on the case studies performed by S&L subsequent to the 2009 Report, it appears that most of the utilities are already employing best operational and maintenance practices.

- The case studies performed in the development of this study estimate that on a weighted average, approximately 1.2% improvement has been achieved to date, while 0.3% improvement is the potential for the future for over 2,500 MW_{NET} power generation. Future improvement strategies are limited, due to the amount of previous improvements already performed on these units. In light of this observation, it appears that a 6% reduction in heat rate, such as that assumed by the EPA from the 2012 baseline, may not be feasible.

- Furthermore, if improvement options are limited to the boiler island, the weighted average past and future potential heat rate improvement is approximately 0.04% and 0.08%, respectively, which would be impossible to verify.[168]

c. EPA's conclusions in the matrix analysis are arbitrary.

EPA states that "…[b]y applying best practices to their operating and maintenance procedures owners and operators of EGUs could reduce heat rate variability relative to average heat rates and, because deviations generally result in performance worse that optimal heat rates, improve the EGUs' average heat rate."[169] To justify the proposed 4% HRI attributable to best practices, EPA apparently identified 355 coal-fired EGUs that had heat rate variations of 8.5 % or more from year to year. Remarkably, EPA finds "…that approximately two-thirds of the large decreases in heat rate can be associated with changes in reporting methods implemented to provide more accurate heat input data. The large changes noted at the remaining one third could not be explained by changes in reporting methodology."[170] But EPA fails to factor this finding that the majority of heat rate variation originated with faulty reporting methods into its matrix analysis. This failure to factor in reporting variabilities is a fundamental flaw.

Regarding the matrix itself, EPA constructs a 168-bin matrix to identify coal-fired EGU BP HRI potential. It reasons that, "other factors held equal, the range of variation indicates that significant potential for heat rate improvement is available through application of best practices."[171] The known factors EPA believes contribute to heat rate variation that it holds constant are unit capacity factor and ambient temperature.[172] EPA determines through a regression analysis that 26 percent of heat rate variation is due to temperature and capacity factor. To determine the portion of the remaining 74 percent that can be ascribed to best practices, EPA constructs its 168-bin matrix containing 14 temperature bins and 12 capacity factor

---

[168] S&L NRECA Report, Attachment B.
[169] 79 Fed. Reg. at 34,860.
[170] GHG Abatement Measures TSD, p. 2-29.
[171] *Id.* at 2-30.
[172] Depending on the unit cooling system and rate of temperature change among other factors, the ambient temperature metric here is questionable technically.

bins, for a total of 168 bins. It then arbitrarily assumes that, for each generating unit, the same output can be produced by reducing the heat input by 30 percent of the difference between the reported value and the value that represents the top 10 percent (the 10th percentile lowest heat rates) in each bin, to arrive at a 4% HRI due to best practices across the fleet. EPA fails to provide any rational basis for this methodology. Is it only coincidence that when the 30-percent factor is applied to the reported bin values, the resulting best practice HRI just happens to equal the 4 percent that EPA incorrectly derived from the 2009 S&L study as attributable to best practices? Also, as stated above, EPA clearly recognizes that reporting errors, recalibration, and other factors significantly affect fleetwide heat rate data, but the Agency apparently made no attempt to explain how these types of errors were accounted for in the 168bin study, or if not why not. Clearly the matrix analysis is an arbitrary exercise not supported by any technical explanation and thus cannot be accorded any weight.

d. The Sixteen-Unit Study does not demonstrate HRI improvements and is arbitrary.

EPA identified 16 EGUs from the study population to find examples of unit year-to-year HRI. In identifying the 16 units, EPA claims that it has filtered out units that underwent HRI due to capacity factor changes, changes in reporting methods or other events; as a result, EPA says, the 16 units have demonstrated a 3-8 % HRI. Further EPA believes that it has identified two EGUs where equipment upgrades have resulted in 2-3% HRI, and EPA, although unable to confirm other unit HRI attributed to equipment upgrades, nonetheless believes that equipment upgrades were the result of HRI in “some” of the other observed unit HRIs.[173]

EPA apparently never contacted the owners of these units to determine what actual factors were responsible for the apparent heat rate reductions, and its failure to do so, especially in a study including only 16 units, is arbitrary and irrational. If EPA had followed a rational analytic process, it would have contacted the unit owners/operators and requested information and data verification. Especially in view of EPA’s assessment, cited earlier, that significant HRI has been associated with changes in data reporting, prudent

[173] GHG Abatement Measures TSD, p. 2-32.

evaluation would dictate that EPA take a close look at data associated with the sixteen units. Table 2 summarizes the causes of the HRI for the sixteen units as determined by industry consultant Ed Cichanowicz in a study conducted for UARG.[174] Cichanowicz made actual contact with the owners of the sixteen units. Based on detailed discussions with ten of the twelve unit owners, the reported heat rate improvements resulted almost exclusively from changes in continuous emission monitoring system ("CEMS") reporting methodology or stack flow monitor calibration rather than from purposeful efforts to improve unit efficiency.

Table 2. Sixteen Reference Units: Summary and Overview

Owner/Unit (Startup Year)	Unit Features	Status
AES/ Petersburg 2 (1971)	471 MW, tangential-fired boiler, Illinois basin coal, ESP and wet FGD. SCR retrofit in 2004.	Gross heat rate reduction by ~3% in 2003 due to steam turbine "dense-pack" retrofit. Other reductions due to CEMS changes. Net heat rate increases 2-3% prior to 2004 due to SCR retrofit and operating variables.
City of Springfield MO/ Southwest 1 (1976)	194 MW, opposed-fired, PRB coal. Combustion controls for NO_x, an ESP, and wet FGD.	Almost all gross heat rate reductions appear to be due to unrelated variability in CEMS measurements Steam turbine dense-pack derived 2% reduction.in the year following retrofit.
CLECO/ Rodemacher 2 (1982)	558 MW, PRB, opposed-fired, hot-side ESP. Combustion controls for NO_x.	All reported gross heat rate reductions due to changes in CEMS operation. Modest decrease in net heat rate (~2%) noted over 11 years but not due to targeted actions.
Duke Energy/ Gibson 1 (1976)	669 MW, E. bit coal, opposed–fired, cold side ESP. SCR retrofit in 2005 and wet FGD in 2007.	Unrelated CEMS measurement changes noted with retrofit of FGD and dedicated stack. Net heat rate based on coal use exceeds CEMS-derived values by 5-10%. The CEMS gross heat rate data lower than unit design basis.
Dynegy/ Newton 1 (1977)	617 MW, cold-side ESP, PRB coal. Combustion controls and coal selection for NO_x and SO_2.	Dynegy evaluating data.
NV Energy/ North Valmy 1 (1981)	254 MW, W. bit coal, opposed-fired boiler, combustion control for NO_x, fabric filter.	All reported gross heat rate reductions due to changes in CEMS calibration or operation.
Nebraska Public	109 MW, PRB, fabric filter.	Gross heat rate when calculated using plant

[174] *See* Cichanowicz Reference Study Attachment C.

Power/ Sheldon 1 (1961)		monitoring equipment increases over the reporting period. A reported gross heat rate reduction of 10% in 2006 is due to CEMS probe calibration.
Pacificorp/ Dave Johnston 2 (1972)	113 MW, PRB, cold-side ESP.	All changes CEMS-related; most due to calibration of stack gas temperature probe in 2005 and 2007. 24 month rolling average of net heat rate increases ~3%.
Pacificorp/ Dave Johnston 4 (1961)	360 MW, PRB, ESP with conditioning.	Steam turbine upgrade in 2009. Replacement in 2011 of: legacy FGD with dry FGD; new stack; rebuilt boiler. CEMS location changed. The reported gross heat rate reduction of 10% is due to CEMS changes. Net heat rate lower ~1% vs. 2009.
Pacificorp/ Jim Bridger 3 (1976)	578 MW, PRB, ESP w/conditioning, wet FGD	All reported reductions due to CEMS operation; notably replacement CEMS flow monitor in 2005. 24 month rolling average of net heat rate decreased by 1.7% due to changes in operation.
TVA/ Colbert 1-3 (1955)	200 MW, low S bit coal, cold-side ESP w/conditioning	EPA conclusions regarding unit gross heat rate are compromised by using as heat input data is reported from common stack CEMS and apportioned by load, based on assumed identical hear rate . Yearly differences in unit operating conditions influence results. Any actual changes in reported gross heat rate are largely due coal blend.
Wisconsin Public Service/ Weston 3 (1981)	350 MW, PRB, tangential-fired, fabric filter.	Heat rate varies between 11,000 and 9,000 Btu/kWh over four years. All reductions in reported heat rate due to CEMS issues.
Xcel/Allen S King 1 (1958)	511 MW (net), cyclone-fired boiler, PRB fuel, original wet venturi FGD. Retrofit w/SCR, dry FGD in 2008.	Refurbishment: boiler cyclones and heat exchangers; coal handling, steam turbine internals; cooling tower. Replaced legacy FGD and ESP with dry FGD and fabric filter; also SCR. Net heat rate actually increases vs. 2003 due to higher station load for environmental controls.
Georgia Power/ Gorgas Two 10 1972	789 MW, bit coal, LNB and SCR, hot-side ESP, 1% S coal	Georgia Power states most changes in reporting gross heat rate are due to the variability and relative accuracy with CEMs-based heat input data.

In other words, EPA's reported heat rate improvements in the Sixteen Unit Study do not reflect actual changes in unit efficiency or reductions in unit CO_2 emission rates. The owners of ten units report that all changes are due either exclusively or almost exclusively to changes in CEMS reporting procedures, most frequently including changes to the method of calibrating the stack gas velocity probe. Some units did report significant initial heat rate improvements from equipment upgrades, such as upgrading the steam turbine, but these improvements were more than offset by increases in net heat rate due to the retrofit of environmental controls.

Thus, EPA has presented no valid documentation regarding the Sixteen Unit Study on which it can rationally justify any of the proposed options for HRI across the coal-fired EGU fleet.

e. NRECA's Nine-Unit Analysis supports the industry study conclusions that EPA's Sixteen Unit Study is flawed and arbitrary.

To summarize, EPA uses the Sixteen Unit study as justification for the proposed 6% HRI by utilizing a statistical evaluation of reported annual heat rates based on Clean Air Markets Division (CAMD) data. Specifically, EPA claims that the identified sixteen units exhibited year-to-year reductions in heat rate of between 3 to 8%, over the period of 2002 through 2011.[175] Contrary to EPA's assertions, the earlier-cited Cichanowicz Report demonstrates that in most cases the reported heat rate annual reductions EPA associated with the sixteen units resulted not from heat rate-improving measures, but from changes in CEMS operation, thus belying EPA's claim.[176]

NRECA augmented UARG's Sixteen Unit analysis with a separate study utilizing data from four cooperatives' generators operating nine coal-fired EGUs.[177] Specifically, reported gross heat rates for nine units operated by Associated Electric, Basin Electric, Seminole Electric, and Sunflower Electric were examined. Almost every unit exhibited gross heat rate reductions of 5% or more in any given year, over the period from 2002 through 2011. In the majority of these cases, the reported gross heat rate reduction was due to a change in CEMS operation. In the case of Antelope Valley Unit 2, high variable capacity factors due to the unit's need to follow wind energy resulted in significant heat rate variation. This observation mirrors results in the NRECA S&L study that demonstrate heat rate inefficiencies are clearly associated with unit cycling. EPA HRI analysis has failed to address the impact of additional wind energy on overall industry fossil fuel-fired EGU heat rates. In short, NRECA's Nine Unit Heat Rate analysis verifies UARG's

[175] Technical Support Document for Carbon Pollution Guidelines for Existing Power Plants: Emissions Guidelines for Greenhouse Gas Emissions from Existing Sources: Electric Utility Generating Units, Docket ID No. EPA-HQ-OAR—2013-0602, June 2014. See p. 2-32.
[176] *Supra* note 170.
[177] NRECA's Nine Unit Heat Rate Analysis. See Attachment D.

critique of EPA's Sixteen Unit analysis that EPA has simply misused its own heat rate data in the Sixteen Unit Study to wrongly determine individual unit and industry-wide potential for heat rate improvements.

To summarize, considering EPA's misuse of the 2009 S&L Report, the NRECA S&L Report correcting EPA's flawed interpretation of this earlier S&L report, EPA's flawed matrix study as identified in the UARG critique, and NRECA's Nine Unit Study, EPA has presented no valid study or data to justify any HRI goal for coal-fired EGUs. The studies or study methods on which EPA relies to support the HRI proposals are either misused or rely on flawed assumptions or faulty analysis. Accordingly, EPA must withdraw the HRI requirements for Building Block 1 because they are not supported by the record.

f. The NSPS "Affected Facility" for heat rate improvements comprises the boiler island and only the boiler island.

For coal-fired EGUs, the existing NSPS regulations define the "affected facility" as the "steam generating unit." See 40 CFR 60.40Da. But the Proposed Rule's discussion of potential HRI at the facility fails to differentiate between potential HRI improvements based on component changes or "best practices" at the "source," as compared to those relevant for the "affected facility." For units undergoing reconstruction or modification, which are considered new units under Section 111(a)(2), EPA has always defined the "affected facility" as comprising only those within the "boiler island." EPA November 1986 Memorandum from Acting Director, Stationary Source Compliance Division, Office of Air Quality Planning and Standards John Rasnic.[178] Mr. Rasnic makes this clear when addressing the "source" components that may be considered part of the "affected facility" for purposes of evaluating whether reconstruction has occurred. He writes, "A steam generating unit includes the following systems: (1) Fuel combustion system (including bunker, coal pulverizers, crusher, stoker, and fuel burners, as applicable). (2) Combustion air system. (3) Steam generating system (firebox, boiler tubes, etc.). (4) Draft system (excluding the stack). *The affected facility then starts at the coal bunkers, and ends at the stack breeching*."[179]

[178] See Letter from John B. Rasnic, Acting Director of the EPA Stationary Source Compliance Division, to James T. Wilburn, Chief of the EPA Air Compliance Division (Nov. 25, 1986). Attachment E.
[179] *Id.* (emphasis added).

Stated differently, *only components at the boiler island* comprise the "affected facility" for NSPS evaluation. Moreover, EPA makes clear that there is no distinction between components that define the "affected facility" for "existing units" as compared to those for new, modified, or reconstructed facilities. On this point, EPA states that "the distinction between 'affected facilities' and 'existing facilities' depends on the date of construction. The terms are intended to be direct regulatory counterparts of the statutory definitions of 'new source' and 'existing source' appearing in section 111 of the Act."[180] Thus, just as for new sources, existing source components defining the "affected facility" exclude components such as those defined by the water treatment and supply systems, the turbine island, main exhaust and main steam piping, and include only components defined by the boiler island, according to EPA's own longstanding interpretation. Therefore, for evaluating HRI under Building Block 1, consideration of improvements to or employment of best practices at components *outside* of the boiler island are "outside the fence line" and cannot be legally part of EPA's HRI mandates.

Moreover, as the NRECA S&L Study concludes, only minimal HRI can be associated with upgrading components comprising the boiler island. If EPA were to correctly evaluate HRI associated with the affected facility as EPA has historically defined it, in accordance with the NRECA S&L study conclusions, the expected HRI would be so small as to be impossible to quantify or verify.[181]

g. EPA correctly excludes combustion turbine HRI requirements

The proposed HRI under Building Block 1 focuses on coal-fired EGUs and does not include HRI requirements for natural gas simple combustion (NGSC) units. We agree with EPA's rationale in this regard, particularly in view of the discussion and analysis contained in the GHG Abatement Measures Document at A-5-6. As pointed out in that document, NGSC currently provides an extremely small amount of total fossil fuel-fired generation—only about 1% of the total. Although this percentage may increase marginally if NGSC utilization increases as a source of backup load in portions of the country developing renewable generation such as wind, any NGSC increase would not be significant when compared to the

[180] 40 Fed. Reg. 58,416, December 16, 1975.
[181] NRECA S&L report page C3.

Nation's total fossil fuel generation. Further, as EPA also points out, NGSC units cycle on and off frequently, making any attempts at implementing HRI at NGSC units largely frivolous. For these reasons, we support the Proposed Rule's exclusion of NGSC HRI from Building Block 1.

2. Building Block 2: Re-dispatch to NGCC

a. EPA's presumption in Building Block 2 that NGCC units can be run at a 70% capacity factor is arbitrary and not supported by the record.

The record for the Proposed Rule provides no support for EPA's across-the-board conclusion that it is technically feasible for existing NGCC units to operate at 70% capacity, yet this is the cornerstone of EPA's Building Block 2 strategy for re-dispatching generation from coal-fired EGUs to less CO_2-intensive NGCC.[182] EPA based this 70% capacity target on its observation that 10% of 464 NGCC plants providing generation data in 2012 had capacity factors of at least 70%.[183] EPA also observed, based on a different set of data, that some units can seasonally operate at greater than 70% of capacity, with 16 percent and 19 percent of units operating at or above that level in the 2012 winter and summer seasons, respectively.[184] Based on this data, EPA "assumed that 70% was a reasonable fleet-wide ceiling for each state" on an annual average basis.[185] Given the small fraction of units that have achieved consistent, or even intermittent, operation at 70% of capacity, the NGCC capacity target set in Building Block 2 is completely arbitrary. The reasonableness of Building Block 2 breaks down even further when the false assumptions in EPA's analysis are considered one by one. By basing its analysis on these false assumptions, the Proposed Rule establishes a 70% NGCC capacity target that is grossly inflated and practically infeasible.

The first methodological flaw inflating state NGCC capacity is EPA's consideration of ineligible EGUs in the calculation of state goals.[186] Under section 111(d), state plans may establish standards of performance only for "any existing source . . . to which a standard of performance under this section would

[182] 79 Fed. Reg. at 34,864-66.
[183] GHG Abatement Measures TSD, pp. 3-7 to 3-9.
[184] 79 Fed. Reg. at 34,863.
[185] GHG Abatement Measures TSD, p. 3-9.
[186] Marchetti, James. Review of EPA's state-specific CO2 emission rate goals: Building Blocks 2 and 3. November 2014. For UARG. See Attachment F.

apply if such existing source were a new source."[187] In this case, the Proposed Guidelines may be used only to establish standards of performance for existing EGUs that otherwise meet the eligibility criteria for EPA's proposed NSPS for GHG emissions from new EGUs.[188] The NSPS for new EGUs applies to any stationary combustion turbine that, *inter alia*, has a base load rating greater than 73 MW (250 MMBtu/h) and was constructed for the purpose of supplying, and supplies, one-third or more of its potential electric output and more than 219,000 MWh as net-electrical sales on a three-year rolling average basis. Data available in the docket suggests that a substantial number of NGCC units used in EPA's calculations would be excluded under Building Block 2 because they do not meet these required criteria for inclusion in section 111(d). Thus the success of Building Block 2 depends on the participation and compliance of units that will not be subject to the Proposed Rule.

EPA also included in its calculation of state goals emissions from and capacity for existing NGCC units that do not currently exist, that have not yet been fully developed, and that may never be completed.[189] South Dakota, for instance, has only one NGCC plant – Basin Electric Cooperative's Deer Creek Station. That plant began operating late in 2012, running at about one percent of capacity, leading EPA to assume, incorrectly, that Deer Creek Station has an additional 69% of capacity available for increased generation. Had EPA treated Deer Creek Station as "under construction," or had it used a different baseline year that properly reflected Deer Creek Station's status as a plant that is not yet operational, the emission reduction target for South Dakota would have looked *very* different from what EPA has proposed.

South Dakota also has only one coal-fired plant, Big Stone, owned by Otter Tail Power, Montana-Dakota Utility Resources, and NorthWestern Energy. Big Stone and Deer Creek Station are located in different RTOs; Deer Creek will be in the Southwest Power Pool as of October 2015, and Big Stone is in MISO. Because the two are in different RTOs, because they have entirely separate ownership, and because they serve entirely different customers, any form of re-dispatch from coal to NGCC in South Dakota, as required by Building Block 2, is not really available.

[187] CAA § 111(d)(1)(A)(ii).
[188] *See* 79 Fed. Reg. at 1430.
[189] UARG comments, Section XIV.C. EPA's Goal Calculation Methodology Is Riddled With Errors.

The Proposed Rule further makes the mistake of basing the state goal calculation on units that are not subject to regulation. Because States cannot impose standards of performance on these units, the increases in NGCC capacity EPA expects them to make will necessarily have to be made by EGUs that *are* subject to EPA regulation. The result is that *affected* NGCC units will be forced to operate at capacity factors significantly above 70% in order to achieve the generation EPA expects States to require from EGUs that the States *may not* regulate.

In addition to basing state NGCC capacity targets in part on units that may not be regulated, EPA also mistakenly estimates the amount of NGCC capacity currently available for dispatch based on unit nameplate capacity rather than net summer capacity. Net summer capacity reflects the maximum output that generating equipment can supply to system load at the time of peak summer demand. Net summer capacity is typically lower than nameplate capacity, because it reflects reductions in capacity caused by efficiency losses and the use of electricity for station service or auxiliary loads for emission control technology.[190] The difference between these two capacities can be substantial, particularly in the Southeast where outside air temperatures are higher.

Net summer capacity is a better indicator of the amount of NGCC capacity available for re-dispatch purposes because it reflects the amount of energy that these units will actually be able to supply to the power grid to replace lost generation from coal-fired sources. Using nameplate capacity rather than net summer capacity in the state goal calculations creates a false impression about the ready availability of NGCC generation for re-dispatch in Building Block 2. For example, in Florida the difference between available NGCC generation from 70% utilization of the actual summer net capacity of 23,784 MW and the existing nameplate capacity of 29,485 MW is a staggering 35,054,309 MWH. The consequence of this difference is that, in Florida, NGCC units would have to operate at an 86.8 percent capacity factor based on their true availability represented by actual summer net capacity, to meet energy needs. The use of

[190] See "Net summer capacity," EIA Glossary, available at http://www.eia.gov/tools/glossary/index.cfm?id=net%20summer%20capacity.

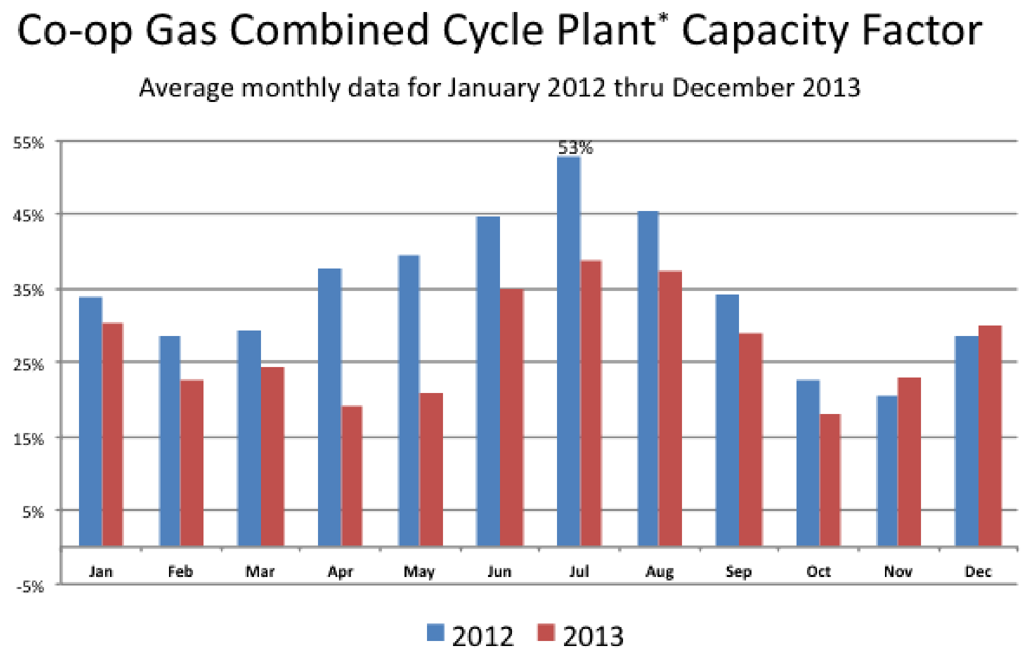
nameplate capacity thus significantly distorts the actual generation that can be provided by NGCC units running at 70% capacity.

This problem is by no means unique to Florida. To support the levels of re-dispatch assumed in the Proposed Rule's state goals, NGCC units in much of the Nation would have to operate at capacity factors far higher than 70 percent. In Arkansas, units would have to run at 83.9%; in North Carolina, 80.9%; and in Texas, 80.1%.[191] When Building Block 2 goals are correctly calculated based on units' summer net capacity, state emission targets rise significantly.

Even if the 70% NGCC target were based on sound assumptions, it is highly unlikely that all NGCC units can achieve it. Currently, co-op NGCC capacity equals approximately 12,000 MW. The vast majority of this capacity was built between 1999 and 2003. Co-op NGCC plant capacity factors averaged 35% in 2012 and 27% in 2013 (see chart below). Only five cooperative-owned NGCC facilities, or 30% of the NGCC capacity, operated at a greater than 60% capacity factor in 2012, when natural gas prices were at a historical low. Fewer than 40% of units industry-wide operated at a 50% or greater capacity factor in 2012.[192] It simply is not rational to assume without data that the technical plant capability, gas, gas transportation, gas storage, and electric transmission capacity are all available or easily developable to double the generators' historic average performance. If there were not limitations at the plant, in the fuel supply, or in the electric transmission, and if the plants were an economic resource, they would have been dispatched more in the past.

---

[191] Marchetti Report, *supra* note 186.
[192] GHG Abatement Measures TSD, p. 3-8.



Co-op gas combined cycle plant capacity factors averaged 35% in 2012 and 27% in 2013. The highest month shown over the period was 53% in July 2012.

Note: Capacity Factor is a measure of plant performance as a percent of its full power potential. It is calculated here as: monthly generation (MWh) divided by Nameplate Capacity (MW) times the number of hours in the month.

*co-op gas combined cycle capacity is 12,000-MW (nameplate); it is primarily for peaking, however, there are 5 large plants (2,000-MW) that operate as base load; those plants have capacity factors above 60%

Source: Ventyx Energy Velocity Suite
May 2014

Many existing NGCC units face substantial barriers to increasing their utilization to a 70% capacity factor. Many units, such as Tri-State Generation and Transmission Association's J.M. Shafer Generating Station (272 MW) and Arkansas Electric Cooperative Corporation's (AECC) Harry L. Oswald (548 MW) Generating Station and Thomas B. Fitzhugh Generating Station (165 MW) facilities, have operating permit mass emission limits and/or fuel usage limits, effectively capping their maximum possible operations below a 70% capacity factor. Other units were financed, designed, and maintained for the specific purpose of operating in cycling duty rather than as base load. Many of these units would not be able to achieve the target utilization rate without significant upgrades and testing to ensure that they are physically capable of operating near full load on a continuous annual basis.[193] Since many NGCC units, like AECC's, have never operated at a 70% capacity factor, there is no historical evidence they can operate as base load. While there is evidence that newer units may operate at this capacity, many older units may be incapable of doing so.

Moreover, as noted above, many of these plants were built for flexibility of generation sources within a region. If they are instead base-loaded, the change would deprive the region of the very flexibility for which the units were built. Taking away that flexibility could force the cycling of less flexible plants, at great cost to their reliability and at significant financial cost to the region, and could force the curtailment of emission-free variable generation because of the lack of available flexible firming resources. EPA must recognize that utilities and regions rely on a diverse portfolio of generation resources to provide different services to the grid. This is like an investment portfolio with a mix of stocks, bonds, and real estate, and different financial instruments with short, medium, and long-term maturities. If an investor is forced to get rid of all of its bonds and long-term investments and put everything in the stock market, that investor becomes subject to far more risk. Like investors, the grid requires a diverse and balanced portfolio of generating resources. Requiring all NGCC plants to operate at 70% of capacity puts that critical diversity in substantial peril. This demonstrates the impracticability and downright hazard of trying to define the best system for operating a complex integrated portfolio of resources for the sole purpose of regulating a single pollutant while ignoring the broad range of other economic, policy, environmental and technical factors that have gone into the design and operation of that system to date.

b. By not addressing economic, technical, regulatory, and infrastructure constraints preventing many NGCC units from operating at the target level, the Proposed Rule fails to demonstrate that Building Block 2 targets are achievable.

In a critical oversight, the Proposed Rule altogether fails to account for the additional gas transportation capacity that will need to be established before NGCC units can meet the proposed 70% capacity factor target. EPA estimates that generation from NGCC units will grow 450 TWh and result in

[193] UARG Comments, Section XV.B. Building Block 2 is Not Achievable.

roughly 3.5 TCF of gas use.[194] This means the power sector faces a 3.5 TCF increase in natural gas consumption—a 43 percent increase in gas use for power generation—just from existing generation sources. EPA's analysis fails to consider this contingency, the additional demands for new baseload gas generation to replace retiring coal-fired units, and the related cost implications stemming from the resulting higher natural gas prices.

i. Infrastructure constraints

Even before the proposed guidance was issued, the Interstate Natural Gas Association of America (INGAA) estimated that U.S. and Canada will need 28,900 to 61,600 miles of additional natural gas pipelines through 2030.[195] More recently INGAA predicted that just to meet existing and forecasted demand over the next twenty years, the U.S. and Canada will need about 850 miles per year of new gas transmission mainline and over 800 miles per year in new laterals to and from power plants and processing facilities.[196] About three-fourths of market growth is occurring in the power sector. INGAA and the Eastern Interconnection States' Planning Council projected that expenditures from 2014-2035 for new pipeline, compression, and pumping infrastructure would be about $10 billion per year.[197] In addition, the U.S. will need 1.4 TCFof new working gas storage capacity, representing a 30 percent increase over 2009 levels, at an estimated cost of $12.5 billion.[198] As seen in the following tables from the Oil & Gas Journal,[199] the U.S. average cost-per-mile for onshore pipeline construction on FERC applications submitted by June 30, 2012, was $3.1 million. No offshore applications have been submitted. Obviously, these numbers would be vastly higher if existing NGCC units were required to double their capacity factor. If States cannot meet the

[194] GHG Abatement TSD, p. 3-12.
[195] INGAA, Natural Gas Pipeline and Storage Infrastructure Projections through 2030, 2009 at http://www.ingaa.org/File.aspx?id=10509.
[196] INGAA, North American Midstream Infrastructure through 2035: Capitalizing on Our Energy Abundance, March 18, 2014 at http://www.ingaa.org/Foundation/Foundation-Reports/2035Report.aspx.
[197] INGAA 2014; EISPC Study on Long-Term Natural Gas and Electric Infrastructure, September 4, 2014 by ICF, webinar.
[198] APPA, Implications of Greater Reliance on Natural Gas for Electricity Generation, July 2010; APPA, Gas Storage Needed to Support Electricity Generation, June 2012.
[199] *Oil and Gas Journal*'s Annual Pipeline Economics Special Report, U.S. Pipeline Economics Study, September 2, 2013

emission reduction requirements EPA proposes for Building Blocks 1, 3, and 4, and more pressure is put on Building Block 2, these numbers will climb higher still.

US PIPELINE COSTS, ESTIMATED

Table 4

Size, in.	Location[1]	Length, miles	Material ($)	Labor ($)	Misc.[2] ($)	ROW & damages ($)	Total ($)	$/mile
LAND PIPELINES								
4	Colorado (lat.)	3	261,100	754,600	626,500	95,000	1,737,200	579,067
	Kansas-Nebraska (lat.)	22	1,446,300	3,686,100	3,588,700	827,000	9,548,100	434,005
8	Tennessee (lat.)	0.53	248,364	636,532	1,133,453	232,296	2,250,645	4,246,500
	West Virginia-Virginia (L)	12.60	2,223,504	276,542	19,003,427	705,750	22,209,223	1,762,637
12	North Dakota (lat.)	79.3	25,297,000	62,208,000	30,154,000	5,100,000	122,759,000	1,548,033
16	Washington (lat.)	3.1	1,891,147	8,489,607	7,853,921	—	18,234,675	5,882,153
	Utah (L)	14.7	3,639,000	466,000	10,537,000	141,100	14,783,100	1,005,653
	Texas (lat.)	16.50	4,305,000	9,352,000	3,435,000	2,665,000	19,757,000	1,197,394
20	Oregon (lat.)	24.30	8,214,000	24,265,000	17,042,000	2,511,000	52,032,000	2,141,235
24	Colorado (lat.)	7.75	6,958,560	8,751,808	8,367,446	939,600	25,017,414	3,228,053
	Pennsylvania /R/	18.52	11,688,756	1,951,311	70,281,833	2,775,000	86,696,900	4,681,258
	Virginia	98.00	58,787,289	89,444,396	34,762,256	5,426,643	188,420,584	1,922,659
24, 30	Mississippi-Alabama	70.00	54,578,000	97,651,000	35,770,000	13,149,000	201,148,000	2,873,543
26	New York (lat.)	0.3	1,540,952	8,462,903	3,336,333	—	13,340,188	44,467,293
	Maryland	21.1	12,498,000	71,424,000	37,036,000	10,984,000	131,942,000	6,253,175
36	Florida /R/	0.31	1,685,160	10,352,686	11,640,966	869,540	24,548,352	79,188,232
	Pennsylvania (L)	2.4	5,947,902	20,596,350	15,870,159	2,374,558	44,788,969	18,662,070
	Pennsylvania (L)	5.3	6,465,914	22,022,266	18,069,185	2,514,701	49,072,066	9,258,880
	Pennsylvania (L)	5.5	5,779,872	19,572,386	15,823,962	3,169,698	44,345,918	8,062,894
	Pennsylvania (L)	6.6	5,816,022	18,716,125	15,876,296	2,242,313	42,650,756	6,462,236
	Pennsylvania (L)	7.1	5,677,095	19,709,928	15,940,496	2,220,100	43,547,619	6,133,467
	Arizona	59	56,595,557	57,415,279	82,922,654	7,316,510	204,250,000	3,461,864
	Oregon	86.8	104,820,706	132,790,981	277,928,009	17,360,000	532,899,696	6,139,397
	Oregon	234	377,411,000	587,291,000	334,979,000	—	1,299,681,000	5,554,192
42	Pennsylvania /R/	0.41	1,246,681	6,249,698	9,833,304	75,000	17,404,683	42,450,446
	Louisiana	21.00	16,000,000	25,000,000	108,814,000	3,200,000	153,014,000	7,286,381
Total projects—land		**820.12**	**$781,022,881**	**$1,307,536,498**	**$1,190,625,900**	**$86,893,809**	**$3,366,079,088**	**$4,104,374**
Total land—2012 report		**144.05**	**$71,422,973**	**$199,261,044**	**$155,598,403**	**$20,373,118**	**$446,655,538**	**$3,100,698**
OFFSHORE PIPELINES								
12, 30	Louisiana	20	22,059,200	24,610,574	25,260,404	—	71,930,178	3,596,509
26	New York (lat.)	2.9	11,899,573	65,352,421	25,761,728	—	103,013,722	35,521,973
Total projects—offshore		**22.90**	**$33,958,773**	**$89,962,995**	**$51,022,132**	**$0**	**$174,943,900**	**$7,639,472**
Total—all projects		**843.02**	**$814,981,654**	**$1,397,499,493**	**$1,241,648,032**	**$86,893,809**	**$3,541,022,988**	**$4,200,402**
2012—report total, all projects		**144.05**	**$71,422,973**	**$199,261,044**	**$155,598,403**	**$20,373,118**	**$446,655,538**	**$3,100,698**

[1]L = loop; lat. = lateral; R = replacement [2]Generally includes surveys, engineering, supervision, interest, administration, overheads, contingencies, allowances for funds used during construction (AFUDC), and FERC fees.
Source: US FERC construction-permit applications, July 1, 2011, to June 30, 2012

10 YEARS OF LAND CONSTRUCTION COSTS[1]

Table 6

Size	Year	Average cost, $/mile ROW	Material	Labor	Misc.	Total	Range, $/mile Low	High
8 in.	2013	71,443	188,261	69,541	1,533,654	1,862,899	1,762,637	4,246,500
	2012	—	—	—	—	—	—	—
	2011	—	132,884	917,910	582,952	1,633,746[2]	—	—
	2010	—	—	—	—	—	—	—
	2009	—	—	—	—	—	—	—
	2008	17,438	378,698	199,342	114,617	710,095	—	—
	2007	—	—	—	—	—	—	—
	2006	—	—	—	—	—	—	—
	2005	—	—	—	—	—	—	—
	2004	239,860	84,651	599,280	591,276	1,515,068	1,507,694	1,518,017
12 in.	2013	64,313	319,004	784,464	380,252	1,548,033[2]	—	—
	2012	75,246	213,859	612,119	419,950	1,321,173[2]	—	—
	2011	—	—	—	—	—	—	—
	2010	—	—	—	—	—	—	—
	2009	—	—	—	—	—	—	—
	2008	178,757	195,406	566,193	466,159	1,406,515	541,392	4,186,636
	2007	—	—	—	—	—	—	—
	2006	45,944	160,618	243,104	174,207	623,873	515,091	1,159,683
	2005	—	—	—	—	—	—	—
	2004	559,684	212,495	1,740,003	691,419	3,203,601	222,012	4,628,800
16 in.	2013	81,810	286,739	533,749	636,324	1,538,623	1,005,653	5,882,153
	2012	126,033	302,558	748,967	302,760	1,480,318[2]	—	—
	2011	278,231	305,235	1,004,152	1,328,691	2,916,309	2,007,514	3,885,413
	2010	263,135	222,719	885,769	966,447	2,338,069[2]	—	—
	2009	226,517	417,899	1,480,926	586,626	2,711,968[2]	—	—
	2008	421,484	1,182,666	1,689,992	1,552,542	4,646,684[2]	—	—
	2007	—	—	—	—	—	—	—
	2006	181,184	192,998	398,048	111,888	884,118	601,274	948,857
	2005	88,312	144,768	238,056	181,419	652,555	396,660	1,728,247
	2004	246,628	141,315	849,567	386,050	1,623,560	353,528	2,529,399
20 in.	2013	103,333	338,025	998,560	701,317	2,141,235		
	2012	8,941	275,292	69,647	1,349,884	1,703,765[2]	—	—
	2011	97,553	402,232	1,208,048	816,998	2,524,831	1,773,309	7,970,976
	2010	64,198	1,194,239	1,663,457	1,504,568[2]	4,426,461[2]	—	—
	2009	164,377	820,867	1,993,079	1,061,331	4,039,654	3,866,474	7,528,043
	2008	23,219	869,178	941,096	491,932	2,325,425[2]	—	—
	2007	—	—	—	—	—	—	—
	2006	99,125	233,125	796,688	478,406	1,607,344[2]	—	—
	2005	28,999	191,553	385,889	187,486	793,927	502,795	1,254,420
	2004	17,254	134,986	999,273	295,479	1,446,991	1,016,598	1,942,989
24 in.	2013	73,560	623,116	805,886	912,622	2,415,184	1,922,659	4,681,258
	2012	181,741	701,303	1,910,324	1,143,928	3,937,296	2,254,386	4,481,436
	2011	283,312	409,840	1,603,609	1,482,417	3,779,177	1,873,984	11,877,953
	2010	—	—	—	—	—	—	—
	2009	65,567	530,093	1,085,736	663,240	2,344,636	1,975,000	3,399,653
	2008	—	—	—	—	—	—	—
	2007	25,467	351,083	324,023	453,737	1,155,030	830,872	4,301,932
	2006	126,822	263,200	584,428	577,136	1,551,586	1,248,916	4,883,022
	2005	99,492	324,099	553,603	289,991	1,267,185	701,664	8,153,531
	2004	1,554,828	409,165	2,913,257	1,165,957	6,043,208[2]	—	—
30 in.	2013	—	—	—	—	—	—	—
	2012	290,807	1,020,108	3,218,952	3,242,493	7,772,360	6,356,657	35,732,500
	2011	390,263	745,675	3,648,578	2,276,889	7,061,405	6,384,345	7,177,507
	2010	160,922	769,453	1,601,563	966,007	3,497,944[2]	—	—
	2009	384,467	624,980	912,342	113,283	2,035,073	1,955,746	3,917,264
	2008	83,016	1,091,147	356,539	472,278	2,002,981	1,684,461	2,264,167
	2007	156,303	1,371,819	1,328,831	922,647	3,779,600	1,546,833	4,715,909
	2006	135,337	589,703	960,760	650,255	2,336,055	1,131,419	6,791,954
	2005	108,418	580,031	1,296,166	639,103	2,623,718	1,333,438	4,082,365
	2004	150,549	448,125	634,490	371,734	1,604,899	1,447,235	2,264,492
36 in.	2013	93,529	1,400,946	2,182,912	1,938,652	5,616,040	3,461,864	79,188,232
	2012	—	—	—	—	—	—	—
	2011	519,369	937,500	2,864,358	3,059,234	7,380,462	7,072,552	7,848,259
	2010	107,000	1,641,171	1,544,020	1,051,506	4,343,697[2]	—	—
	2009	499,329	1,083,073	1,084,429	892,446	3,559,276	3,284,505	3,600,324
	2008	170,489	994,375	1,098,096	511,589	2,774,549	2,427,457	9,013,608
	2007	97,746	869,995	628,204	893,293	2,489,238	1,857,468	4,056,369
	2006	233,258	844,583	1,141,388	1,349,079	3,568,308	1,900,376	8,066,157
	2005	161,665	819,178	929,436	633,630	2,543,909	1,424,610	4,798,806
	2004	150,070	426,999	352,594	565,474	1,495,137	—	—

[1]Estimates; based on FERC construction-permit applications for a 12-month period ending June 30 of each year. [2]Only one project proposed during this period for this diameter.

Based on the survey in the report, pipeline costs recently have risen to $155,000 per inch-mile from $94,000 per inch-mile. Regionally, costs vary significantly, with costs being considerably higher in the northeastern States where the need is greatest and significantly lower in the southwestern States. Costs also are assumed to vary by grade of pipe, so the smaller diameter pipes used mostly in gathering systems have lower cost factors applied. The costs for pipes that are less than 12 inches in diameter are assumed to range from $20,000 to $70,000 per inch-mile.

NERA has projected that most States will see increased total gas demand by 2020 relative to the maximum they have recently consumed (i.e., in 2012).[200] In addition, NERA has identified historically constrained interstate and intrastate natural gas pipelines. The combination of these measures allowed NERA to identify a top tier set of 18 States facing natural gas supply risks. Of the 18 States, 10 have natural gas demand increases of more than 25 percentage points;[201] 7 have significant natural gas shares of baseload generation (>35%);[202] and one State qualifies under both criteria.[203] In these States, even an occasional difficulty in obtaining gas could affect electricity reliability with additional risk for electricity price pressures.

Given the time-consuming and expensive siting and permit processes for pipeline, storage, and other midstream natural gas infrastructure, EPA's proposed timeline for infrastructure improvements is infeasible. EPA suggests that pipeline infrastructure will have sufficient time to expand if necessary to accommodate Building Block 2 because the proposed rule "provides for flexible implementation that will permit efficient scheduling of infrastructure upgrades as needed."[204] Presumably, EPA is suggesting that States may delay full implementation of Building Block 2 because compliance with the proposed state interim goals is based on average emissions from 2020-2029.

The "flexible implementation" timeline is largely illusory, however, particularly with respect to Building Block 2. For most States, re-dispatch under Building Block 2 accounts for the most significant emission reductions of any Building Block, and EPA calculated the proposed state goals with the assumption that Building Blocks 1 and 2 would be fully implemented by 2020.[205] Delaying full

---

[200] NERA, "Assessment of the Impact of the EPA's Proposed 111(d) Targets on Natural Gas Demands by State." November 2014 for NRECA gas study, Attachment G.
[201] IN, IA, KY, MD, MO, NC, OH, PA, VA, and WV.
[202] AL, CA, FL, LA, NV, OK, and TX. All of these states except AL exceed a 50% natural gas share of baseload under the EPA's proposed regulation.
[203] AZ.
[204] GHG Abatement Measures TSD, p. 3-16.
[205] 79 Fed. Reg. at 34,905-06; *see* Goal Computation TSD at 18 (noting that in calculating state goals, only "the RE and EE assumptions change for each year from 2020 through 2029").

implementation of Building Block 2 to allow for necessary infrastructure development would significantly increase state emissions in the 2020 to 2029 compliance period, forcing States to achieve more drastic emission reductions in later years, possibly even exceeding the emission reductions required under the final emission targets, in order to comply with the interim goal. Thus, most States will need to implement necessary infrastructure improvements to accommodate Building Block 2 by 2020 or soon thereafter.[206]

ii. Constraints resulting from other statutes and regulatory regimes

The impossibility of actually implementing Building Block 2 is further assured because FERC regulation preempts many of the actions Building Block 2 assumes the States will take. Unlike new electric transmission, which does not necessarily need to be approved by FERC,[207] new interstate natural gas transmission facilities *must* receive FERC review and authorization.[208] FERC generally does not authorize new pipeline capacity unless customers have already committed to using it (*i.e.*, have firm delivery contracts), and pipelines are prohibited from charging the cost of new capacity to their existing customer base.[209] To ensure that pipeline capacity closely matches the needs of new customers, FERC approves new facilities and facility improvements only after new customers have requested firm service. If all of the pipeline's firm customers use their full capability, then there will be little or no excess pipeline capacity to support NGCC units' efforts to achieve the 70% capacity factor target.

Other federal statutes that affect the construction of interstate natural gas pipelines include the Clean Air Act, Clean Water Act, the Endangered Species Act, the Coastal Zone Management Act, the Fish and Wildlife Coordination Act, the Historic Preservation Act, the Rivers and Harbors Act, the Mineral Leasing Act, the Federal Land Policy Management Act, and the Wild and Scenic Rivers Act. A host of

[206] In the Notice of Data Availability, EPA solicits comment on whether the final rule should include a phase-in schedule for the Building Block 2 interim goal based on the need for infrastructure improvements. Because NRECA believes that a binding phase-in schedule cannot be developed in advance, and because NRECA believes the interim goals are unrealistic even with such adjustments, NRECA believes the interim goals should be eliminated altogether.
[207] NERC, 2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States. December 2011. http://www.nerc.com/files/gas_electric_interdependencies_phase_i.pdf.
[208] NERC, 2013 Special Reliability Assessment: Accommodating an Increased Dependence on Natural Gas for Electric Power. Phase II: A Vulnerability and Scenario Assessment for the North American Bulk Power System. May 2013. http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_PhaseII_FINAL.pdf.
[209] NERC 2011.

federal, state, regional, and local approvals are necessary for pipeline construction to begin. Urban development has encroached on many existing pipeline right-of-ways, thereby making some expansions parallel to existing pipelines difficult to implement. Projects often are opposed by multiple stakeholders, including landowners, environmentalists, and others with competing interests. FERC, under the Energy Policy Act of 2005, may be able to streamline this process in order to facilitate expeditious development of pipeline capacity, or it may become even more time consuming and difficult to construct natural gas pipelines. Large projects like the Alaska pipeline can take decades of discussion and planning, and can require a decade to permit and construct once a route is chosen. Less controversial and smaller pipeline capacity can be built within a year or so if transportation costs justify construction and permits are obtained in a timely manner.[210]

iii. Constraints arising from interdependencies between natural gas and electric generation

The Proposed Rule also fails to account for the complex interdependencies between the natural gas and electricity industries. Gas-fired generators relying on very congested pipelines face frequent supply issues. When power plants cannot receive fuel services that allow the generator to operate in response to an ISO's or RTO's dispatch, reliability is threatened. A great deal of work is presently underway at the FERC and in industry standards organizations to address the inconsistencies between the gas and electric markets. Progress has been made, but there is a long way to go and no certain outcomes from the process.[211]

During the 2013-2014 Polar Vortex, when home heating loads increased and received priority delivery, pipelines were less able to provide power plants with flexible services like non-ratable consumption. For example:

(1) Arkansas Electric Cooperative Corporation had a firm transportation gas contract during the winter. In early December, with an onset of cold weather, AECC's gas supplier issued an Hourly-Takes Advisory, requiring that their gas plants run ratably

[210] INGAA 2009.
[211] NERC, 2011, 2013; EISPC Study on Long-Term Natural Gas and Electric Infrastructure, September 4, 2014 by ICF, webinar.

(at a constant level) over a 24-hour period. This limited flexibility for 66 days during the winter during which AECC could not vary the gas take over the day and could not respond to the changing needs of the grid; AECC would have incurred penalties to start up its gas turbines. In January 2014, the supplier issued Operational Flow Orders (OFO) and Critical Time Declarations with the same result, significant charges and penalties if the gas units were started. The gas take restrictions were in effect through most of the winter, with the supplier finally lifting them in early April 2014.

(2) Wolverine Power Cooperative in Michigan had limited gas transportation availability in January 2014 during the Polar Vortex when residential and small commercial gas users took precedence over electric generation. Despite a critical need for generation in MISO, Wolverine was unable to secure sufficient gas deliveries to operate all its gas units. Even though it had sufficient gas in storage to operate its units, access to storage gas was limited or prohibited. The storage access restriction forced Wolverine to purchase natural gas at market prices that reached $75/Mcf, about 25 times the prevailing price today.

(3) Hoosier Energy's Holland Energy facility experienced periods of extreme natural gas prices based on elevated demand and pipeline outages. These physical limitations, combined with differences in the operational structure of the natural gas and electricity markets, made it extremely difficult to obtain fuel and run the facility. As a result the plant only ran 4 days from the period January 1, 2014 through March 31, 2014. Based on produced versus potential MWhs, the facility had a capacity factor of 1%.

In the above examples, cooperative generators dealt with prolonged periods during which "normal" gas supplies were unavailable due to extreme and competing demands on supply. New pipeline infrastructure will take a significant amount of time and money to site and build, while States and utilities are up against EPA's compliance deadlines. There are many moving parts in this plan—assuring sufficient gas pipeline and supply to gas turbines and sufficient transmission from generators to load—that need to fall into place without a hitch to meet EPA's timeline. Even with sufficient gas supplies, EPA timelines are too tight to assure adequate transportation and storage for periods of high demand. Natural gas pipelines still have limited capacity and infrastructure available to offer flexible operating services to power plant customers on a firm basis.

NERC's Polar Vortex Review revealed that within the Eastern and ERCOT Interconnections, over 37,000 MW of outages were due to cold weather failures and fuel issues.[212] As seen in the figure below, natural gas units represented over 55 percent of the total outages during the Polar Vortex, twice the rate of coal units. NERC concluded:

> *Increased reliance on natural gas during the polar vortex exposed the industry to various challenges with fuel supply and delivery. This increased reliance, compounded by generation outages during the extreme conditions, increased the risks to the reliable operation of the BPS.*
>
> *As the industry relies more on natural-gas-fired capacity to meet electricity needs, it is important to examine potential risks associated with increased dependence on a single fuel type. The extent of these concerns varies from Region to Region; however, they are most acute in areas where power generators rely on interruptible natural gas pipeline transportation.*

Indeed, the lights almost went out during the Polar Vortex, but that was with many tens of thousands of MWs of coal-fired capacity that will not be there in the future if this rule is finalized in its present form.

[212] NERC Polar Vortex Review. September 2014. See at http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

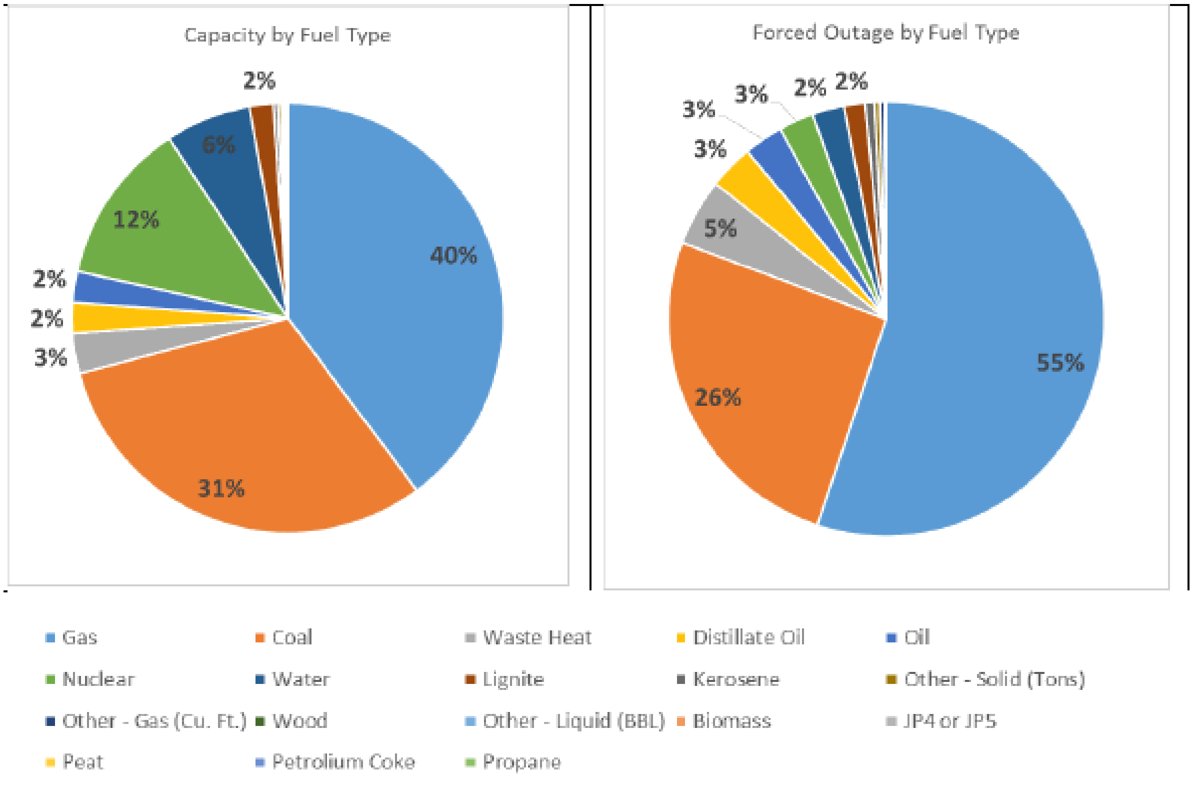


Figure 13: Percentage of Net Dependable Capacity by Fuel Type (left); Percentage of Capacity Lost During Polar Vortex by Fuel Type (right) in Eastern and ERCOT Interconnections

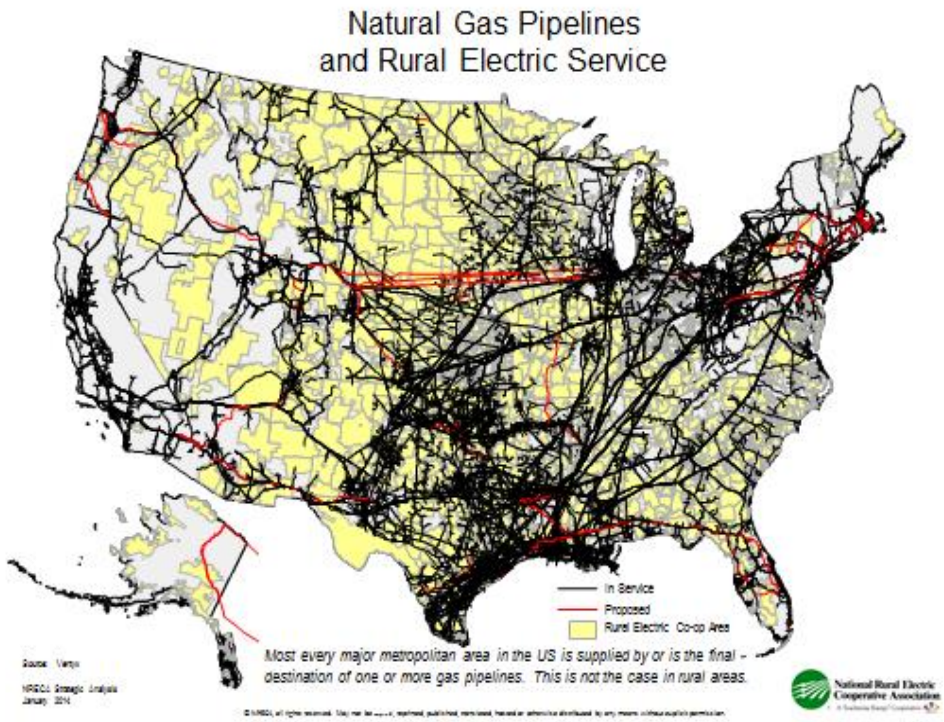
Relative to other customers, the electric industry presents significant challenges for the natural gas industry and, in particular, to its pipeline and local gas distribution segments.[213] From the perspective of the natural gas industry, it is more difficult to meet the needs of electric customers than it is to meet the needs of its residential, commercial, and industrial customers. The high point loads, high pressure loads, large variation loads, and non-ratable takes involved with serving the electric industry present major challenges for the pipeline industry. Furthermore, the electric industry has an increasing need for system flexibility to accommodate intermittent renewables. Electric utility loads are also as large as or larger than many local distribution company (LDC) loads and, in some cases, exceed the capabilities of smaller diameter pipelines. In addition, these electric utility loads mostly occur at a single point, whereas almost all the LDC loads are served over multiple city gates.

[213] NERC, December 2011, A Primer of the Natural Gas and Electric Power Interdependency in the United States.

Another challenging aspect for electric gas loads is the associated high pressure requirements. Consistent fuel pressure is necessary for the generator to meet operational and environmental requirements. Newer, larger, combustion turbine/combined cycle units are less tolerant of variations in pressure than older units. High pressure drives highly efficient gas-fired units. While the electric utilities continue to increase their pressure requirements to improve their overall fuel efficiency, the increased requirements can impair overall pipeline flexibility and response capability.

The variability of electric gas loads is another challenge for gas distributors. More problematic for the gas industry than seasonal electric gas load variation are daily and weekly variations (*i.e.*, non-ratable-take issues). Daily variation is particularly difficult for pipelines to accommodate because they were initially designed for steady hourly load profiles (*i.e.*, 1/24 of the daily consumption requirement each hour). Pipelines are thus unlikely to be able to provide the fuel necessary to meet daily peak electricity demand. Peak demand will thus have to be met by coal-fired or nuclear-powered units. If coal-fired units are prevented from being dispatched—or are required to close—under the Proposed Rule, then implementing the Rule presents significant risks of power failure at peak times.

Building Block 2 also poses major regional challenges that the Proposed Rule fails to recognize and address. Natural gas suppliers are significantly limited or simply not present in many of the rural areas where electric cooperative baseload facilities are located. As shown in the map below, natural gas supply pipelines may be hundreds of miles away from where additional electric generation may be required to serve cooperative rural service areas. Even where pipelines are available, the availability of firm gas supplies at a reasonable price is an ongoing uncertainty.



The Proposed Rule further assumes without support that the gas distribution infrastructure needed to support increased reliance on gas generation exists or will soon be built. This may be true in certain parts of the country, but not others. Gas pipeline developers are reluctant or even unable to build pipelines without "anchor" customers, like the natural gas generation owners that use gas.[214] These generation owners, however, will not commit to the long-term contracts unless they know how they will be dispatched in the long-term.[215] Gas generation facilities are uncertain of how they will be dispatched in today's market, and they do not yet know what EPA's environmental dispatch will require.[216] Their dilemma is further complicated if generators are in organized markets that serve multiple States: under the Proposed Rule, generators may be dispatched at different levels (and require different levels of fuel) depending on the location of their loads and their state's specific environmental dispatch requirements.[217]

[214] Moeller House Testimony at 4.
[215] *Id.*
[216] *Id.* at 3-4.
[217] *Id.* at 2 ("The biggest challenge in implementing the proposed rule is that electricity markets are interstate in nature. Thus the proposal's state-by-state approach results in an enforcement regime that would be awkward at best, and potentially very inefficient and expensive.").

In the Notice of Data Availability (NODA) issued on October 30, 2014, EPA requests comment on using NGCC to reduce CO_2 emissions from the power sector as a whole—either through new generation or co-firing—and just for redispatch from fossil fuel-fired generation. It is blatantly unlawful for EPA to require the construction of new generation assets as part of BSER for existing sources. Additionally, requiring co-firing is tantamount to fuel switching, which EPA has stated is not BSER.[218] At the very least, requiring facilities to build co-firing capacity would result in a modification to or reconstruction of an existing source. It is absurd to think that Section 111(d) authorizes EPA to require facilities to make such dramatic changes that the facility then becomes subject to double-regulation under Section 111(b).

EPA also seeks comment on whether and how NGCC targets should be established regionally. Nothing in Section 111(d) gives EPA *any* authority to set regional generation or emission targets. Section 111(d) only provides authority for the establishment of state-specific standards of performance, and it expressly reserves to the individual States the authority to set those standards. Specifying targeted levels of generation shift under Building Block 2 for multi-state regions would thus be unlawful.

c. The Proposed Rule fails to account for additional electric transmission capacity, expansion timelines, and costs.

EPA believes that existing electric transmission networks can now support an aggregate operation of the NGCC fleet up to a 70% capacity factor on average, or that they can do so following timely modifications. Modifications to the electric transmission infrastructure will need to be based on changes in the location of generation with respect to load. The analysis EPA has conducted of the current system is procedurally inadequate and significantly underestimates the time required to modify transmission systems and the complexities involved.

Modifying the electric transmission infrastructure is a complex, costly, and time consuming process that involves many state and federal agencies, electric utilities, and the public. Once EPA accepts

[218] *See, e.g.,* GHG Abatement Measures TSD, p. 6-9 (EPA's "analysis suggests that cost-effective reductions of CO_2 are not available on a national basis from widespread adoption of natural gas co-firing," though this should not "preclude the potential for individual EGUs to utilize co-firing as a way to reduce CO_2 or other emissions, nor does it preclude states from factoring in that unit-level potential into the design of state plans for compliance with the 111(d) standard.").

state implementation plans under the proposed rule, it will take about two or more years for generation and transmission entities to analyze the potential requirements of their systems due to all the different possible combinations under EPA's proposal. Then plans for additional electric transmission must be developed and analyzed in an open regional planning process that usually takes an additional two years. Every change requires new analysis, and the building resources market can change while the analysis is being conducted. In the best circumstances, a four- to five-year planning period will be necessary before an approved transmission plan can be achieved and the transmission construction process can begin. This optimistic timeframe may be inadequate for a State to meet EPA's proposed goals. Some projects take 10 years to build, while others never get built. For example, the Potomac-Appalachian Transmission Highline (PATH) project was proposed to address numerous electric reliability concerns forecast for the Mid-Atlantic region in the mid-2000s. Companies committed to build the project and sought regulatory approvals from Maryland, Virginia, and West Virginia. Although the project made it through a regional planning process, the regional authority, PJM Interconnect, asked the developer to suspend PATH efforts in 2011 after the project faced significant opposition and failed to obtain approval despite filing several applications over a two-year period. The economic downturn and changing public policies, particularly with respect to renewable energy, had increased the uncertainty of PJM's planning studies.

In addition to the time needed for planning, cost allocation issues will need to be addressed, rights-of-way must be acquired from landowners, and permits must be obtained. Permits for associated environmental issues such as endangered species are a moving target, as the U.S. Fish and Wildlife Service is currently making listing decisions on 250 candidate species through 2018. Public opposition and lawsuits seeking to stop or move planned transmission are also common and can add substantial delay and expense to transmission projects. It is not yet clear what modifications to transmission infrastructure may be required to support a re-dispatch of existing NGCC capacity to achieve a 70% or greater capacity factor, but those changes will also need to be addressed through regional planning processes and may also take up to five to 10 years to complete once identified. There are more problems with siting new transmission now than ever before, so lead times for those proposed new facilities could be even longer.

The targets and timelines required in the Proposed Rule do not accommodate the timelines and regulatory realities involved in expanding electric transmission capacity. The addition of new transmission will also be costly. A typical new 69 kV overhead single-circuit transmission line costs approximately $285,000 per mile, while the same line run underground line costs around $1.5 million per mile. A new 138 kV line costs $390,000 per mile if run overhead and $2 million per mile if run underground. Entities are unlikely to risk the expense of expanding electricity transmission capacity if the electricity is required to be displaced by energy efficiency in a few years.

Cost per Mile: New Construction Transmission[219]

	Overhead		
	Urban	Suburban	Rural
Minimum	$377,000	$232,000	$174,000
Maximum	$11,000,000	$4,500,000	$6,500,000

3. Building Block 3: Nuclear and Renewables.

a. Building Block 3 cannot legally be part of BSER

Nuclear and renewable generation cannot be part of BSER for several compelling legal reasons. First, neither nuclear nor renewable sources fall within the target source category, and EPA's authority under Section 111 does extend beyond that category. Second, BSER must reduce emissions within a source category; replacing source category generation with zero-emitting generation *outside* the source category is not BSER. Third, BSER cannot lawfully be "applied" outside of the "affected facility" within the specified source category—here, fossil fuel-fired EGUs. Fundamentally, BSER is directed at *reducing* emissions at an operating facility *within a source category*. Therefore, BSER targeting facilities outside of the specified source category *cannot* serve as BSER for the source category. Thus, EPA's inclusion of Building Block 3 as part of a BSER for fossil fuel-fired EGUs is plainly unlawful.[220]

[219] EEI January 2013.

[220] In its October 30, 2014 NODA, EPA requests comments on various means of determining State RE targets based on different regional constructs. As discussed in Section III.B.2.c. above, EPA has no authority to set targets or standards of performance on a regional level.

b. EPA's assumptions in Building Block 3 concerning the availability of nuclear and renewable generation are neither supported by the docket nor practice, and are otherwise arbitrary and capricious.

EPA inexpertly assumes that non-hydro renewable generation will increase from 217,868 GWh in 2012 to 522,723 GWh, (about 140% growth, or 7.1% per year) to make up around 13% of national generation by 2029. This assumption is wholly ungrounded in theory or practice.

To determine state targets, EPA used state performance data, based on the share of 2012 generation from non-hydro renewables within each State (the "renewable penetration rate"). EPA then determined regional target levels of performance by dividing States into regions that it assumed (contrary to good evidence) to have similar renewable resource potential and current performance. Recognizing that some States are especially rich in high-potential alternatives, EPA set goals for non-hydro renewable penetration rates based on existing state RPSs and set the 2030 renewable goal rates based on the un-weighted average of 2020 RPS goals for States in the region with existing RPSs. States lacking RPS were excluded improperly in setting the average. EPA did not credit any fossil fuel sources (*e.g.*, coal bed methane in PA) in setting the targets.

In so doing, EPA assumed it knew better than States without RPSs or with below "average" RPSs what the "best" resource portfolio in those States should be, based solely on what would reduce CO_2 and without addressing any of the many factors States consider in setting renewable goals, including the cost of renewable resources and other options available in those States, the need for economic development for different business sectors, availability of other fuels in the State, availability of transmission in the State, the costs and benefits of achieving environmental, economic, and power supply goals through alternative means such as tax credits and investment incentives, economic conditions for electric consumers in the State, and many more. EPA also ignores the details of all of the RPSs it reviewed that reflect many of these considerations, such as reliability exemptions, cost caps, and inclusion of renewable resources not counted as "renewable" by EPA, such as hydro, stranded gas, and coal-bed methane.

Starting in 2017, EPA applies regional annual growth factors to 2012 generation levels for all States in a region to prescribe regional goals. Thus, EPA assumes that renewables in all States within a region will grow at the same rate to reach their targets, and will maintain their relative ranks in renewable penetration.

The proposal also stipulates an interim goal that averages the State's RE performance level from 2020-2029. Unlike treatment of renewable generation in state RPSs, the proposal's goals only recognize renewable resources developed within state borders. A State's target goal is determined by using its initial 2012 RE level multiplied annually by a calculated growth factor to reach the 2029 state target. Because electric systems are integrated, many renewables are developed to meet demand and/or RPS requirements in neighboring States and benefit from the grid balancing and other integration services inherent in our interstate system. The proposal's treatment of renewable electric generation that is transmitted and distributed interstate is arbitrary and capricious. The Proposed Rule is in general inconsistent, arbitrary and capricious in its treatment of all types of generation that serve multiple States.

c. EPA's failure to address cost allocation of additional renewable generation and resulting transmission needs affords no opportunity for meaningful comment, and is otherwise arbitrary and capricious.

The proposal utterly fails to address the critical issues of how the costs of the renewable resources needed to attain state goals will be allocated and who has the responsibility to mandate such allocations. With no proposal, there can be no meaningful opportunity for comment on the implications of the Proposed Rule. We can say this much: there are practical limitations to renewable deployment, including costs and timing of constructing additional needed electric transmission, that result in projects taking up to five to 10 years to permit and build. The Proposed Rule's failure to acknowledge these constraints and limitations or to provide *any* rational explanation or resolution for dealing with these constraints is arbitrary and capricious.

The addition or modification of transmission infrastructure to support the needed increase in renewables generation is a process carried out in the market place, not by RTOs, States, or FERC. States have authority over siting and permitting of generation and transmission facilities. State and regional institutions determine how to allocate costs, subject to FERC orders, which affects the market risks for a range of stakeholders, including project developers. The result is a complex mix of legal issues and political dynamics that impact plans to deploy renewable electricity technologies. Expanding the use of renewable electricity poses political challenges that are often more formidable than the technical challenges. The proposal fails to acknowledge these political challenges even exist.

In addition to the time needed by the market to plan modifications to transmission infrastructure, players must negotiate how transmission costs will be assigned (who pays), acquire rights-of-way from landowners—often many—and obtain permits. Permits for associated environmental issues such as endangered species are a moving target, with the U.S. Fish and Wildlife Service in the process of making listing decisions on 250 candidate species through 2018. Other issues include permits to cross federal lands under the National Forest Management Act and/or the Federal Land Policy and Management Act; state water quality permits; fish, game, and other wildlife related permits if the project will affect fish and game; National Historic Preservation Act consultations if the project may impact cultural or historic resources; and rights-of-way permits on tribal land.[221] Public opposition and lawsuits seeking to stop or move planned transmission are also common and can significantly impact the schedule for developing new transmission infrastructure.

Transmission cost allocation is controversial and one of the most important issues to resolve if significant transmission system expansion is to be realized. The mechanisms by which costs are recovered for new transmission and how they are divided among different users and customers raises equity issues because customers and regulators in one State may object to paying for benefits that accrue to customers in another State. Most cost allocation conflicts have occurred over transmission, but they may also include renewable energy integration costs and bulk storage costs in the near future.

It is not yet clear what modifications to transmission infrastructure will be required to support an increase in renewables as required by this proposal, but those changes may take up to five to 10 years to complete once identified. There are more problems with siting new transmission now than ever before, so lead times for those proposed new facilities could be even longer.

[221] USDOE, USDOI, May 2007, Energy Policy Act of 2005, Section 1813 Indian Land Rights-of-Way Study: Report to Congress. http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/EPAct_1813_Final.pdf.

d. EPA's assumptions concerning the availability of new renewable generation on a statewide basis are contrary to practice, unsupported by the record, and indicative of EPA's failure to correctly interpret its own data.

In two regions that EPA uses to define individual state goals within the respective geographic areas - the eight-state Southeast and the six-state South Central - only one State in each region has a RPS in place. And yet EPA assumes that every State in these regions can meet targets based on that single State's RPS. EPA fails to provide a systematic look at the actual renewable potential across the States in these two regions and fails to explain why it assumes that one State in each of these two regions is representative of what *all* States in these regions can reasonably accomplish. EPA's failure to factor States without any RPS requirement into the regional averaging is irrational and arbitrary.

EPA's proposal fails to recognize or consider that many state RPS policies have cost caps to ensure that the renewable mandates are not overly costly and that these costs caps can operate to limit future renewable expansion that EPA projects is needed to achieve statewide goals.

In the South Central region, EPA used the Kansas standard, but improperly extracted the numeric standard without applying the other determinates in the Kansas RPS statute. The imaginary Kansas RPS that EPA applies to establish the regional goal is based on energy, yet the actual Kansas RPS is a capacity-based requirement established for seven utilities operating in-state – Sunflower Electric (and Mid-Kansas Electric), Midwest Energy, Westar, KCP&L, Empire, and KCK Board of Public Utilities.[222] It does not apply to any other cooperative or municipal utility in the State, nor does it apply to the load served by these utilities in other States. The Kansas RPS also treats as renewables certain resources that EPA does not treat as renewables in the guidance – specifically hydropower. These failures to accurately evaluate the Kansas RPS and adjust the region's renewable goals make the region's goal irrational, unsupportable, and capricious. Further, since the Kansas RPS does not apply to utilities in the State other than the seven named, or to the loads served by these utilities in other States, even if EPA were to adopt the real Kansas

[222] KSA 66-1256 at http://www.kslegislature.org/li/b2013_14/statute/066_000_0000_chapter/066_012_0000_article/066_012_0056_section/066_012_0056_k/.

requirements as indicative of a region-wide target, the target would have to be reset to represent a value consistent with the proposal's definition of renewable generation under Building Block 3.

Continuing with the above example of EPA's treatment of the South Central region, Arkansas has no state RPS and limited capacity for developing renewable resources. Arkansas does not have the wind resource potential of Kansas, Nebraska, Oklahoma, or Texas. It has small amounts of solar resources using current technologies. Arkansas has the potential for developing biomass resources, but it is currently unclear whether biomass generation will be considered CO_2 neutral in the final rule. It has existing hydropower with some potential for development. Under the proposal, Arkansas has a 20 percent renewable energy-based target in 2029 of 4790 GWh. But given that the Kansas RPS is capacity-based, not energy-based, the Kansas RPS is actually 12 percent energy-based. Therefore Arkansas' renewable energy target in 2029 should be 12 percent energy-based, or at most 2872 GWh, *60% lower* than the proposed target. Thus, if EPA were to adopt the real Kansas requirements as indicative of a region-wide target, the target should be no greater than 12 percent.[223]

Similarly, in the Southeast region, EPA used the North Carolina standard. As in the South Central region, EPA extracted the numeric standard without applying the other determinants in the North Carolina RPS statute.[224] The North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS) counts existing hydropower,[225] renewable energy credits (REC), and energy efficiency to fulfill the requirements.[226] There are provisions in the North Carolina REPS that allow utilities to petition for a waiver if mandates are not attainable.[227]T he use of the appropriate determinants would reduce the effective 2020 in-state renewable generation target for the Southeast region to 5 percent, half of what EPA proposed.[228]

[223] AECC Comments on EPA's 111(d) Proposal, submitted September 30, 2014.
[224] Marchetti, *supra* note 186 at 27.
[225] Existing hydropower is only credited to cooperative and municipal utilities.
[226] North Carolina Statute G.S. § 62-133.8. See http://www.ncleg.net/EnactedLegislation/Statutes/HTML/BySection/Chapter_62/GS_62-133.8.html.
[227] North Carolina Statute G.S. § 62-133.8(i)(2). See http://www.ncleg.net/EnactedLegislation/Statutes/HTML/BySection/Chapter_62/GS_62-133.8.html.
[228] Marchetti, *supra* note 186 at 27.

e. EPA's failure to account for necessary additional intermediate generation to balance added renewable generation is arbitrary and capricious, and renders the proposed scheme unworkable.

A significant portion of the additional renewable generation needed to attain Building Block 3 goals is wind that is inherently intermittent. Thus, additional reliable backup generation would be required to ensure grid reliability and proper balancing. Additionally, system frequency and voltages must be maintained within defined, extremely tight tolerances. In this light, both wind and solar PV technologies, principally relied on by EPA to meet Building Block 3 goals, present challenges to power system operators, owing to variability and uncertainty of their generation output on the timescales relevant to the task of maintaining system reliability.[229] The proposal has failed to consider these needed generation resources and how they would be acquired and financed. This is a significant fault in this proposal.

For example, the California ISO, with its RPS of 33 percent of retail electricity from renewables by 2020, indicates its grid's flexible generator capacity is nowhere near what it needs to be to accommodate increasing wind and solar energy on the grid.[230] Any capital investment costs for increased flexible generator capacity, transmission system build-outs, and associated O&M cost increases, will be charged to rate payers via rate schedules and fees on electric bills, not to wind turbine owners. There is no indication in the rulemaking docket that EPA is even aware of these challenges or how they could be met under this proposal.

f. The proposal arbitrarily and capriciously ignores the fact that most renewable generation is not built by entities regulated by this proposal, that States have no legal authority to force additional investment in renewable generation without additional legislation.

The proposal relies heavily on additional renewable generation as a means to achieve the state goals. Most States cannot simply mandate additional renewables though RPS. Such authority must come from state legislative actions that can take several years to enact considering that many state legislatures meet only biannually. Moreover, the legislatures must agree to enact additional mandates, which they may

---

229 http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC-CAISO_VG_Assessment_Final.pdf.

230 http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf .

or may not do. Most States simply have no authority to adopt mandates that additional renewable generation be built. Moreover, the entities building renewable generation such as wind are not affected entities under this proposal, because they are not in the identified source category; thus they have no incentive to do so, particularly if the production tax credit is not renewed in the future.

g. The proposal's treatment of nuclear power generation irrationally treats nuclear power different than other sources that comprise Building Block 3.

EPA's approach unfairly and severely penalizes States that are leading in the expansion of nuclear energy in America. Further, it is inconsistent with U.S. energy policy and the President's own statements in support of expanding nuclear energy. Finally, EPA's approach in Building Block 3 exceeds EPA's authority under section 111(d) of the Clean Air Act because nuclear units are not part of the regulated source category.

The proposed treatment of under-construction nuclear power generation is arbitrary and capricious. Unlike other generation sources in Building Block 3, the proposal treats even under-construction nuclear generation as *existing* generation for the purpose of goal rate-setting. The result of this treatment is to effectively penalize those electric utilities that have invested in under-construction nuclear units (and their consumers), who will incur very significant costs to bring online this CO_2-free generation but will get no credit for that generation as a compliance option. Other under-construction zero-emission generation sources in Building Block 3 are not treated in this manner. These other generation sources are excluded from the goal rate-setting; thus, they receive credit for zero-emission generation when they come online and ultimately contribute power to the grid. This discriminatory treatment of under-construction nuclear, when there is no identifiable difference between it and Building Block 3 renewables, is irrational. As a consequence, EPA's proposed Building Block 3 is arbitrary and capricious. EPA can remedy this by treating under-construction nuclear units like it treats all others: as irrelevant for goal rate-setting, but available for goal compliance once constructed.

By taking into account nuclear units under construction in this manner, EPA has set CO_2 emission targets for Georgia, South Carolina, and Tennessee that are substantially more stringent than these targets would otherwise be if EPA did not include these units in the goal rate-setting calculation. For example, South Carolina's state target is 28 percent more stringent because of EPA's treatment of the under-construction Summer 2 and 3 nuclear units. This is a substantial and unjustified penalty levied on just three States for no legitimate purpose. In fact, including these under-construction plants in the rate-setting algorithm drives Georgia's 2030 intensity target for existing sources down to 834 lbs./ MWH, and South Carolina's to 772 lbs./ MWH. This is well below the 1,100-lb/ MWH New Source Performance Standard established in EPA's 111(b) rulemaking governing new fossil-fired power plants. As noted earlier in these comments, it is irrational and arbitrary to have an emission rate standard for existing power plants that is below the emission rate specified for new power plants.

In sum, the five reactors under construction – Vogtle 3 and 4, Summer 2 and 3, and Watts Bar 2 – should be excluded from the rate-setting formula. Their outputs should count toward compliance, however, as should any other new nuclear capacity once it is online. Plants that extend their licenses beyond 40 years or beyond 60 years should, of course, also continue to receive credit in compliance calculations.

Further, EPA's failure to account for both planned and unplanned nuclear power outages, and its assumptions on future anticipated annual capacity usage, are arbitrary and capricious. The proposal assumes that the average annual nuclear plant generation availability or capacity factor is approximately 90 percent of the time on a national basis. This assumption is without foundation. The average lifetime capacity factor of the 100 nuclear plants through 2013 is 80.3% according to the Nuclear Energy Institute (NEI).[231] Although the average plant capacity factor in 2012 was 86% according to EIA figures, EPA offers no basis to conclude that overall the average annual capacity factor will increase above the long term historic levels. Under EPA assumptions of unjustified high nuclear generation capability, the proposal's Building Block 3 goals appear to be more attainable than they actually will be, simply because EPA arbitrarily assumes more CO_2 -free nuclear power will be utilized than is realistically plausible.

[231] IAEA's Power Reactor Information System database: http://www.iaea.org/PRIS/WorldStatistics/LifeTimeEnergyAvailabilityFactor.aspx.

In a particular year, a particular plant may be off-line 30% of the time or more. For instance, there were six planned outages lasting longer than 100 days between 2000 and 2014, and a total of 34 planned outages with an average duration of 86.2 days.[232] Outages of this type and duration create a huge void in what EPA assumes is a steady, constant supply of CO_2-free generation that somehow must be compensated for with increased generation from other sources in Building Block 3. Again, no support is offered for EPA's assumptions.

When a nuclear generating facility goes off-line, over 50 percent of the CO_2-free generation in an individual State may become unavailable *instantly*. For example, in 2012, Connecticut generated 979 GWh from renewable sources (including hydropower),[233] while in 2013 a single nuclear reactor generated 9,520 GWh.[234] If that single reactor was offline for 1/3 of a year, approximately 2,856 GWh would not be generated – nearly three times the entire amount of electricity generated by renewables in the State in 2012.

There are 23 States in which a single nuclear reactor generated as much or more electricity in 2013 as the State's entire fleet of renewables (including hydropower) generated in 2012.[235] It is impossible to replace such large volumes of CO_2-free generation overnight.

In addition, electric utilities owning existing nuclear power plants may not be able to make or, in some instances, may not have the authority to make, the extensive capital investments that are frequently required for license extension projects. Thus, existing facilities may shut down in the future. EPA has not accounted for these likely realities, and it has not provided any mechanism or means to adjust state goals accordingly.

h. EPA's treatment of "at risk" nuclear generating capacity does not create a true incentive for owners of these facilities to keep them operating.

In the Proposed Rule, the nuclear generation component is based on a percentage of existing nuclear capacity (6%), which EPA considers at risk of premature shutdown. EPA based this on the Energy

[232] NEI, Durations of Steam Generator Replacements Spreadsheet.
[233] EPG, GHG Abatement Measures Technical Support Document, Table 4-1.1 (June 10, 2014).
[234] NEI U.S. Plant Cap Factors Spreadsheet, *supra* note 232.
[235] Calculations based on EPG, GHG Abatement Measures Technical Support Document, Table 4-1.1 (June 10, 2014), and NEI US Plant Cap Factors Spreadsheet.

Information Administration's 2014 Annual Energy Outlook study that concluded about 6% of all U.S. nuclear units would be retired for various reasons in the near term. EPA assumes 6% of a State's 2012 nuclear capacity runs at a 90% capacity factor and then adds those megawatt-hours when calculating a State's intensity target. States are then allowed to take credit for up to 6% of the generation from these units in their compliance calculations, which, in EPA's view, provides States an incentive to avoid premature nuclear shutdowns. However, 6% is not an incentive if it merely holds a utility or State whole—that is, if 6% of "at risk" nuclear generation is used in calculating a State's goal, a 6% credit for compliance simply makes the economics of running the "at risk" units neutral at best. This is not really much of an incentive to a utility, if any, to keep an "at risk" unit running. If EPA wishes to provide a true incentive, it should take the 6% out of a State's goal calculation, but allow States to take compliance credit for up to 6% of the generation from "at risk" facilities.

If EPA insists on keeping the 6% in the goal calculation, the Agency should allow a higher percentage of existing nuclear generation to be counted in meeting individual state goals—for example, 20% instead of 6%. While these existing nuclear units do not emit any CO_2, they do represent significant initial investments by their owners. These units also require high levels of capital expenditures to maintain operations and to comply with ever-evolving safety requirements. Increasing the percentage of nuclear generation counted towards the state goal to 20% would create meaningful incentives to keep operating these units as they approach the end of their lives and to build new CO_2-free nuclear units. However, increasing the nuclear contribution toward *meeting* state goals to 20% should not result in any increase in *setting* individual state goals.

i. Dispatchable zero-emission EGUs (*i.e.*, nuclear) have an inherent future risk of compliance.

In those States that are heavily dependent on nuclear generation to comply with the existing power plant rule, there is an inherent risk that these units will fail to produce electricity. In that event, there will be no way for those States to comply with the proposal's emission rate targets without the construction of back-up zero-emission technology. Many States will and can use gas-generated electricity in combined cycle combustion turbines as a failsafe method to guarantee compliance with state goals well into the future. However, those States that are heavily dependent on zero-emission generation such as nuclear generation and additionally have federally mandated state emission goals below the known emission level of combined-cycle combustion turbines must have back-up generation of additional zero-emission technology to ensure meeting both FERC n+1 standards of redundancy and the proposed EPA rule. If under-construction and at-risk nuclear units are considered in the proposed state emission limits, these States may be forced to have available back-up zero-emission technology that may be both high cost and non-dispatchable.

This is clearly not a feasible approach. Not only would it cost consumers an unconscionable sum to invest in gigawatts of unneeded renewable capacity simply to provide back-up in case they should lose a nuclear resource, but no realistic amount of intermittent renewable resource could provide the same consistent and reliable energy as a nuclear generator. Moreover, that very investment would ensure that the nuclear generators would close, as that investment in renewable resources would flood the energy and capacity markets, driving prices down to the level that nuclear plant operators could never recover enough money to justify keeping the power plants open.

States simply cannot control whether nuclear plants shut down and cannot contract in advance to fully insulate themselves from the environmental impacts of such shut downs. That is why EPA must permit States to adjust their state-wide emissions goals to reflect the next best resource option that the State is able to develop to replace any nuclear plant that may close.

j. The proposal's failure to account for ongoing variability of hydropower and the potential for permanent hydropower diminishment due to new environmental constraints is arbitrary and capricious.

EPA does not include hydropower in calculating state goals, but it arbitrarily assumes existing capacities of hydropower will always be available in future years. Many regions of the country rely heavily on this generation, but the proposal fails to account for natural circumstances that lead to reduced capacity on a yearly and sometimes multi-year basis. For example, the proposal fails to address how to supplement, or who will be responsible for supplementing, existing hydro when the presumed generation levels are diminished based on drought, reduced capacity due to new environmental mandates, or reductions based on other competing interests such as drinking water reserves or even beach creation. Under the proposal, the State's overarching goal would remain unchanged, posing additional burdens on other resources to make up the difference due the reduced hydropower availability.

For example, in North Dakota, thermal generation supplements power from dams in low water years. In high water years such as 2012, state emissions are lower. The Pacific Northwest is heavily dependent on hydropower and would encounter the same problem as North Dakota when hydropower generation power is curtailed. Many States will and can use natural gas EGUs to make up for the lost hydropower generation. However, due to the stringency of state goals and the proposal's heavy reliance on this gas generation for meeting the state goals, there may not be available natural gas generation to replace the lost hydro power; moreover, the required natural gas use may cause the State to exceed its SIP due to unanticipated usage.

The table below summarizes the at-risk hydropower capacity nationwide.

U.S. Hydro Capacity "at Risk"

Retirement Risk Factor	Capacity *(%)*
Announced Retirement by 2030	2%
Merchant Ownership	10%
Over Age 50 & < 25 MW	10%
License Expiration by 2030	29%

Sources and Notes:

Ventyx Energy Suite, and SNL Energy.

Additional risk factors such as high operating costs and expiring PPAs are not shown above since the data is available for a subset of the hydro units.

By 2030 the application of these risk factors will likely lead to permanent reductions in the nation's hydropower generation. EPA capriciously ignores the impacts of this likely reality, and as a result, as described immediately above, many States will be forced to rely on additional natural gas generation not accounted for by EPA in state goal calculation. This additional CO_2-based natural gas generation could well make it impossible for many States to achieve the proposal's goals.

k. EPA's accounting for hydropower conflicts with the treatment of other renewable energy and is arbitrary and capricious.

For the purposes of calculating a baseline level of renewable generation in each State, EPA includes only non-hydropower renewable energy in the target-setting calculations and in the renewable generation levels used to inform the state goals. EPA reasoned that inclusion of hydropower in current and projected levels of renewables would distort the proposed approach by presuming the future development potential of large hydroelectric capacity. EPA also assumed that state RPS policies often exclude existing hydroelectric facilities from RPS accounting. But, recognizing that there is potential for the development of new hydropower resources, EPA proposed that a State may choose to include generation from new hydro facilities as a method of compliance with a State's goal.

In this approach to goal rate-setting and compliance, EPA has failed to recognize the details, limitations, and variations in state RPS statutes. For example, North Dakota only counts *new* hydropower generation for compliance with its RPS. But North Dakota recognizes the importance of *existing* hydropower in how it calculates the amount of electricity necessary to meet the RPS. A utility may deduct the proportion of electricity obtained from hydroelectric facilities from its baseline of total retail sales, lessening the burden. The National Hydropower Association supported a similar approach when Congress was discussing a national renewable standard. Other States such as Kansas include existing hydropower in their definition of renewable energy resources for compliance purposes under their RPS.

EPA's treatment of hydropower disadvantages parts of the country that rely on zero-emission hydropower resources as a significant proportion of their renewable generation. EPA should recognize the importance of the continued contribution of hydropower to the Nation's renewable energy resources. EPA should revise its approach to allow States to count existing hydropower generation toward their renewable energy goals.

4. Building Block 4: End-use energy efficiency

a. The Proposed Rule's end-use energy efficiency requirements exceed both EPA's authority and the authority of most state environmental agencies, and their inclusion in the underlying rule analysis and justification of the emissions targets undermines the entire rule.

EPA has determined that significant improvements in end-use energy efficiency (EE) are to be a primary means of achieving greenhouse gas emission reductions even though these requirements are based on the conduct of *consumers* of electricity rather than generators of electricity, and are beyond the control of EPA, most state environmental agencies, and utilities. As we discuss elsewhere in these comments, Section 111 does not authorize EPA to extend its jurisdiction beyond the stationary source by attempting to regulate demand for the good, service, or product that source produces. In this instance, the source is the coal-fired EGU and its good or service is electricity. Virtually every business, institution and household in the country requires energy in the form of electricity, and that energy is provided by existing EGUs. Using EPA's logic in Building Block 4, which requires increases in end-user energy efficiency and other efforts to reduce demand, this proposal could well apply to every consumer of electricity and is well beyond EPA's authority. Without the reliance on the outside-the-fence-line consumer end-use efficiency that EPA assumes States can achieve, EPA's analysis and justification for state emission limits falls apart, undermining the emission reduction targets set forth in the rule.

b. EPA's analysis underlying Building Block 4 is flawed, arbitrary, and capricious, and therefore the inclusion of end-use energy efficiency as an element of BSER for purposes of setting emission rate goals is invalid

EPA's analysis is flawed and fails to address many fundamental issues associated with using end-use electrical efficiency "outside-the-fence-line," or in well-accepted greenhouse gas accounting terms "outside the organizational and operational boundaries" of state governments and power plant owner/operators, as a means to reduce the power sector's greenhouse gas emissions. EPA's failure to adequately address the fundamental issues associated with assuming that end-use efficiency measures lead directly to the assumed emissions reductions results in a flawed analysis and the establishment of arbitrary and capricious emission limit requirements.

i. EPA's analysis that establishes a nationwide 1.5% annual EE savings goal is arbitrary and capricious

EPA's proposed nationwide 1.5% energy savings goal is unrealistic in many States. This is because it fails to account accurately for extreme variations in demographics, regulatory environments, load growth, and usage patterns among States and utilities. In fact, EPA has ignored several examples across the country where annual energy efficiency savings are declining. This unrealistically inflates the Proposed Rule's state-level CO_2 emissions targets and increases the burden on the other three CO_2-reducing building blocks. For example, actual kWh from Maine, Vermont, and Washington, among others, shows that EPA's across-the-board 1.5% savings goal is unrealistic.[236] These States set out aggressive energy efficiency savings goals and yet in each case they have not been able to achieve them. The reasons for the shortfall typically include challenges in fully funding the programs and in building broad and rapid adoption of the program by residential, commercial and industrial consumers. While they have made some progress, ramping up the programs and sustaining funding for them have been a significant challenge.

An analysis conducted by NRECA further demonstrates that EPA's nationwide 1.5% annual EE savings goal cannot be achieved and sustained at the state level or by many individual utilities. The study shows that EPA's own data is inconsistent with its assumption that all States can achieve, and then maintain, a 1.5% annual EE savings goal. EPA's assumed savings goal is flawed because it is based on insufficient data that draws comparisons among a limited number of States that are not representative of the savings that are actually achievable across the Nation. At the individual utility level, particularly from the cooperative perspective, NRECA's analysis demonstrates why many cooperatives cannot technically or cost-effectively achieve EPA's 1.5% annual savings goal. EPA's analysis is defective when assessing individual utilities because it ignores essential differences among utilities that are fundamental to assessing EE savings goals, such as size, location, load characteristics, and projected load growth.

---

[236] EnerVision Inc.: Supporting Research for NRECA Energy Efficiency Block Comments to EPA. Attachment H.

As these examples and analyses show, any across-the-board energy efficiency savings goal would be arbitrary and capricious. Per Section 111(d)'s command that standards of performance for existing sources be set by the State, the individual States should determine what goals from energy efficiency savings, if any, can be realistically achieved and maintained given the unique circumstances of the State and its utilities. EPA should eliminate the Building Block 4 goal.

ii. Not all States can cost-effectively achieve and sustain the 1.5% annual energy efficiency goals

EPA identified approximately twelve States that have achieved, or are "on a path" to achieving, a 1.5% annual EE savings, and it extrapolated from that analysis that, nationwide, a 1.5% annual EE savings is reasonable.[237] As our analysis demonstrates, the 12 States EPA selected do not accurately represent the nation's landscape, nor do they represent the various energy efficiency capabilities across each State. Further, EPA's analysis of the 48 States that submitted their 2012 data via Form 861 to the Energy Information Agency (EIA) shows that only three States (Arizona, Maine and Vermont) have actually achieved an incremental savings of 1.5% or greater, while 45 other reporting States (including nine States EPA deemed to be top performers) have much lower savings ranging from 0.00% to 1.24%.[238]

EPA also acknowledges that the EIA data-gathering process has gone through several significant iterations and that only in 2011 did the reporting through Form 861 provide a more comprehensive and consistent assessment of what EE activities are taking place in States. This suggests that EPA's approach to determining a nationwide goal for achieving EE savings was, at best, supported by data from 2011 - 2012 and that much of the data from previous years were inconclusive, or not readily comparable.

NRECA performed a detailed review of the EIA Form 861 data and energy efficiency potential studies that EPA assessed to develop the target 1.5% annual savings goal. NRECA also evaluated each "energy efficiency potential" study relied upon by EPA's meta-analysis and compared the detailed information in those studies to the Table on pages 5-65 and 5-66 of EPA's Technical Support Document. NRECA identified several major flaws with the analysis developed by EPA including:

---

[237] 79 Fed. Reg. at 37,872.
[238] GHG Abatement Measures TSD, p. 5-16.

- In the potential study meta-analysis, EPA used incorrect data extracted from some of the 12 potential studies examined. For example, for the Commonwealth of Pennsylvania, EPA has used a cumulative annual savings figure of 2.9% that covered a three-year future period as a one-year kWh savings figure. This is an obvious error that NRECA has confirmed with the author (GDS Associates) of the 2012 Pennsylvania energy efficiency potential study. When this and other data errors are corrected, the 1.5% average kWh savings calculated by EPA decreases by at least 20%.
- EPA incorrectly calculated the achievable potential savings percentage for the 2010 Salt River Project potential study in Arizona. Arizona is one of the States EPA touts as achieving the 1.5% annual energy efficiency goal. For the Salt River Project potential, however, the average incremental annual percentage savings was shown as 1.4% per year, not 2.2%.
- The achievable energy efficiency savings potential for 6 of the 12 States examined in the EPA meta-analysis is much less than 1.5% per year. NRECA believes it makes no sense to assume that all 12 States included in the EPA Technical Support Document can achieve 1.5% energy efficiency savings annually when many of the studies reviewed by EPA found that the potential in those States individually, and on average, is far less than 1.5%.
- NRECA reviewed the electricity savings and retail kWh sales data from the 2012 EIA Form 861 and recalculated the 2012 Incremental and Cumulative Savings for each State.[239] NRECA found mistakes for 19 areas of EPA's Table 5-4 on pages 5-17 through 5-19 (17 States and the Continental US Total and US Total). In all of the 19 areas where NRECA identified these errors the EPA results were higher than the actual values, resulting in an EPA average 2012 Incremental Savings of 0.58% versus NRECA's corrected calculation of 0.51% (*i.e.*, EPA's results were 14% too high). EPA also assumed a 0.2% per year "conservative" improvement in annual Incremental Savings for each State. This EPA assumption means each State would need to increase the actual average U.S. Incremental Annual Savings percentage by approximately 40% (.2/.51) each year from 2012 into the future.

[239] *See* Attachment I.

- Significantly EPA failed to take into account state-to-state differences in the legislative, regulatory, economic, demographic, and geographic and climate characteristics. There are also state laws in effect that place a cap on the amount that can be spent on energy efficiency programs. Moreover in some instances, state energy efficiency programs have simply run out of money such as the Maine program.[240] When evaluating data from both leading and lagging state energy efficiency programs, it is not clear that all States can achieve savings of 1.5% a year with energy efficiency programs, because of key differences among States.
- Sreedharan (2013) and Eldridge (2008) do not justify the 1.5% annual energy efficiency goals, as EPA contends they do. Ten of the fifteen Eldridge studies and 7 of the 10 studies in the Sreedharan analysis did not achieve the 1.5% goal.
- The three States that have achieved the 1.5% annual savings have had their EE programs for over 20 years, yet EPA's proposal would require all covered States to achieve similar or greater savings by 2025, just over 10 years away. Based upon EPA's own data, achieving the 1.5% annual savings is well beyond what has actually been accomplished in practice.

Given all of this evidence, it was arbitrary and capricious for EPA to assume that all 48 covered States can achieve the annual savings target for energy efficiency of 1.5% of kWh sales. Each State needs to have an energy efficiency potential study completed for its geographic territory in order for the EPA's approach to be realistic and credible.

EPA further assumes the EE programs, once implemented to a level of 1.5% annual savings, can be sustained at that level. Yet EPA acknowledges that this level of savings has been achieved by only a few States, and no State has demonstrated that these rates can be sustained over several years.[241] In fact, the Arizona Corporation Commission recently proposed to scale back their EE program as Commissioner Gary Pierce stated that the cost was exceeding the benefit to consumers.[242]

---

[240] EnerVision, *supra* note 236.
[241] *Id*. p. 5-34.
[242] Arizona Republic November 5, 2014: "Arizona energy-saving programs in jeopardy" by Ryan Randazzo

States need to establish EE programs and goals based upon more reasonable assumptions that are, in turn, based on actual state-specific data, and EPA needs to adjust the individual state baseline goals accordingly. In our review of existing EE programs, it comes as no surprise that the programs are varied and that many States set their standards based upon a range of factors that include: economics (including funding for rebates and subsidies), reducing peak demand vs. overall energy demand, and residential vs. industrial or commercial customer bases. Significantly, all state programs focus on situations where the EE benefits can exceed cost.

For these reasons, the States and not the EPA should determine whether and, if so, how to implement EE programs and to set goals based upon their unique circumstances. EPA does not allow a State to conduct the unit-specific analysis expressly contemplated by the statute and instead arbitrarily assumes all regulated sources can achieve the limits, or that some sources will have to exceed targets to offset lesser reductions from other sources.

EPA also requests comment on establishing an even higher EE goal of a 2.0% annual energy efficiency savings and a 0.25% growth rate to achieve that goal. NRECA opposes this approach for the reasons stated above. As discussed, most States are nowhere near achieving a 1.5% goal, and the compliance deadline EPA establishes to meet that goal is less than half the time it took the three leading States to achieve that level of annual savings. Only one of those States has achieved over 2%. As we discussed earlier in these comments, under Section 111(d) EPA's role is to establish BSER; it is up to each State to establish the standards of performance for and to apply those standards to each existing source within its borders.[243] EPA cannot displace the States' authority to develop their own standards of performance, and therefore it should be the States and not the EPA making the decisions on whether or how they choose to implement an EE program. The States will base such determinations on actual state-specific data rather than EPA's arbitrary speculative assumptions about their abilities to make consumers use less electricity.

[243] 42 C.F.R. § 7411(d)(1).

iii. Not all individual utilities can achieve and sustain a 1.5% annual energy efficiency goal

NRECA commissioned an analysis[244] to determine the ability of individual utilities to meet EPA's 1.5% annual energy efficiency savings goal. That study concluded that many individual utilities will be unable to achieve the EPA's proposed 1.5% goal. While EPA recognized the differences in energy generation between States in its detailed development of targets for CO_2 emissions; EPA's uniform energy efficiency target inexplicably fails to account for the broad differences that likewise exist from State to State in the consumption of energy. These differences, not just among States, but also among utilities within the same State, play a key role in determining the appropriate level of cost-effective, achievable, and sustainable energy efficiency.

For example, Arizona is one of the three States that EPA cites as achieving a 1.5% of savings in 2012 due to Energy Efficiency Resource Standards. Yet in the creation of the state EERS, the Arizona Corporation Commission (ACC) accounted for the dissimilar nature of investor-owned utilities and distribution cooperative utilities. This is shown in the discounted standard allowed for distribution cooperative utilities written into the State's EERS.[245] Despite the flexibility provided, many Arizona utilities, both investor-owned and distribution cooperative utilities, have not met their standard since 2010, and a number of Arizona entities have been granted waivers from the ACC which allow the entity to not attain the standard targets.

The waiver process is also written into the Arizona EERS language,[246] further emphasizing that from the outset the ACC understood that the original standards were potentially set higher than entities could attain, necessitating a waiver process. This mirrors what is occurring with several other electric utilities and distribution cooperatives in other States that also have not been able to meet or exceed their required energy efficiency goals. Even though EPA cites Arizona as achieving the intended 1.5% mandate

[244] EnerVision, *supra* note 236.
[245] Arizona Department of State, Arizona Administrative Code, Title 14. Public Service Corporation, Chapter 2. Corporation Commission Fixed Utilities, Article 24. Electric Energy Efficiency Standards http://www.azsos.gov/public_services/Title_14/14-02.htm.
[246] *Id.*

in 2012, a closer look at the individual utilities' savings over several years in response to the state EERS program shows that a 1.5% mandate is unreasonable and unsustainable, particularly for distribution cooperatives. In the two examples from distribution cooperatives cited by Enervision, one would only be able to meet 34% of its cumulative goal and the other would only achieve 11% of their goal.[247]

In fact, on November 4, 2014, the Arizona Corporation Commission proposed to eliminate the 2010 energy efficiency mandate they had adopted citing the growing cost was outweighing the energy efficiency benefits. Commissioner Gary Pierce stated "At the end of the day, we want to be as energy-efficient of a state as we can, but not overpay for this energy efficiency." Pierce indicated that in the early years of the program, much of the low-cost energy efficiency upgrades had been adopted while utilities were now being forced to grasp for any means to reduce energy usage, regardless of the cost.[248]

In the case of Minnesota, another State with an ambitious goal of 1.5% annual energy efficiency savings, the cooperatives face a significant cost not only to achieve the goal, but the costs are exorbitant when compared to both IOUs and municipal utilities.[249] The average cooperative cost per kWh saved through adoption of energy efficiency measures is more than double the cost to other utilities in the State. The cooperatives also spent 6.95% of their gross operating revenue to achieve the reductions, which is again, almost twice the cost of other utilities.

In Washington State, utilities of a certain size, including two cooperatives, were allowed to set their own EE goal.[250] Both cooperatives subject to the program were able to achieve the target savings set for themselves based on potential savings studies documented in their implementation plans. However, despite showing achievement of target savings, it is important to note the trend of actual percent energy efficiency savings. For both of these cooperatives, the percentage of actual EE savings *decreased* year-on-year. This is common to most utility EE programs where the low-hanging fruit options are easier and lower cost to implement in the first years of any EE program. In each subsequent year, as these low-cost options are

[247] EnerVision, *supra* note 236.
[248] *Id.*
[249] *Id.*
[250] *Id.*

exhausted, it becomes more expensive to implement additional programs and more difficult to find customers willing to participate to a greater extent and at a greater up-front cost.

As these examples demonstrate, the ability of individual utilities to achieve EPA's goals varies significantly. Further, the cost to an individual utility can be substantial, whether it can actually achieve the goal or some lesser amount of savings. These factors must be considered when establishing energy efficiency goals. This would require the individual State, not EPA, to complete the proper analysis and devise a program that is reasonable and achievable.

iv. EPA ignores the significant upfront cost to States, utilities, their consumers, and in particular, rural customers required to adopt EE programs

By ignoring its statutory obligation to allow States to conduct a unit-by-unit analysis for determining what they can reasonably achieve in emission reductions, EPA instead proposes to establish statewide goals that assume all sources can achieve the goal. Under this zero-sum construct, even if the State determines that a cooperative or other utility could not achieve what EPA prescribed, other utilities would need to make up the difference. This removes any incentive for a State to fairly evaluate what an individual utility could achieve and set its requirement accordingly. Similarly, it precludes the State from determining what could be achieved through development of EE programs and setting those requirements. For purposes of meeting the EPA's expected goal of 1.5% annual energy savings from EE, States may well feel pressured to require *all* utilities to achieve the same level, even when in reality they cannot.

v. The cost of achieving EPA's EE goals will place a significant economic burden on cooperative consumers

Distribution cooperatives are most often responsible for implementing EE programs in their territories and frequently they have limited resources to help offset the costs of these programs for their customers. These cooperatives are typically small, averaging fewer than 48 employees, and they serve vast rural territories that average 7 meters per mile. Electric cooperatives face significant challenges in implementing EE programs that are likely to raise their costs significantly compared to other utility program administrators. In addition, due to their small size, distribution cooperatives often have too few consumers to recover the costs of implementing energy efficiency programs without burdening members. As discussed in greater detail elsewhere in these comments, over 62% of cooperative customers are residential, and cooperatives serve the vast majority of the nation's persistent poverty counties as well as other high-poverty areas. Electric cooperatives serve more rural territories where the housing stock is dominated by detached single family homes, including a disproportionate share of mobile homes.[251]

EE programs must make sense for the particular area for which they are proposed, as adopting these programs in rural areas can pose a significant cost on what is a limited number of customers. The low density of these areas often means a lack of energy efficiency vendors and service providers who tend to focus on more lucrative markets in more densely populated areas. Further, the EE program in these areas will likely result in limited EE benefits towards meeting the state goals.[252]

EPA offers two nationwide estimates of Levelized Cost of Saved Energy (LCSE) for the average utility based on discount rates of 3% and 7%. EPA's high-end estimate for 2017 is 9.9 ¢/kWh[253], equal to the national average retail rate for electricity. But a review of the economics literature points to a national LCSE of 11.5 ¢/kWh, or about 16% higher, using the same 7% discount rate. As EPA acknowledges, these costs escalate over time as programs are ramped up towards EPA's goal of 1.5% and the marginal costs of additional energy savings rise.

Typically EE programs are designed to split the cost so that consumers foot half of the bill, so half of this cost would be borne by program administrators such as electric utilities, while the other half would be borne directly by consumers. Because distribution cooperatives are not-for-profit businesses owned by the consumers they serve, the distinction between what costs are borne by the cooperatives and by their member-consumers is blurred. Ultimately, any costs incurred to run an energy efficiency program are borne by consumer-owners through higher electric bills. The unique business model of electric cooperatives is well suited to pursue cost-effective energy efficiency programs, but EPA's arbitrary targets offer no

---

[251] NRECA estimates that nearly 17% of housing stock in electric cooperative territories are mobile homes, more than double the national rate of 6.5%.
[252] https://www.nreca.coop/wp-content/uploads/2013/12/EMVReportAugust2012.pdf, at *2.
[253] All figures in this section are in constant 2011 dollars.

evidence that the additional costs will ultimately save our consumers money. This is a significant cost for consumers on top of other increased costs they will bear in the monthly electric bill driven by EPA's rulemaking. EPA's analysis of end-use efficiency fails to properly account for the upfront consumer costs of energy efficiency upgrades and thus results in a flawed analysis for target setting.

A report by Lawrence Berkeley National Laboratory (LBNL)[254] cited extensively by EPA highlights energy efficiency program constraints faced by program administrators serving a large share of residential and/or low-income consumers. While the report does show a low weighted average administrator[255] LCSE, it also shows median costs for residential programs more than twice the weighted average, and both average and median administrator costs for low-income programs double to triple those of other types. Additionally, both residential and low-income programs show a very wide interquartile range, meaning that there is great cost variability across these programs.[256] This suggests that many areas will face much higher costs than the "average" used by EPA. Most cooperatives will likely face administrative costs higher than the averages that are dominated by more densely populated urban areas.

EPA assumes a low-end LCSE based on a 3% discount rate, and a high-end based on a 7% discount rate. A review of scholarly research on energy efficiency and behavioral economics reveals a possible "energy efficiency gap," a market failure wherein consumers, especially residential consumers, are less inclined to make large up front investments for uncertain long term gains.[257] Unlike large businesses, the average homeowner is less inclined or able to make the kind of "cost minimizing" decisions that many economic models are based upon, whether due to imperfect information or simply a lack of time, money, or interest. Even when consumers have the necessary information, these investments are often not attractive if

[254] Billingsley, M.A., I. M. Hoffman, E. Stuart, S. R. Schiller, C. A. Goldman, K. LaCommare, *The Program Administrator Cost of Saved Energy for Utility Customer‐Funded Energy Efficiency Programs*, Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division, March 2014, Figure ES‐1, p. xii.
[255] These are administrator costs, not including the total cost in which roughly half is borne directly by the consumer.
[256] LBNL shows a median administrator costs for residential programs at 4 ¢/kWh, 1.6 times the weighted average of under 2 ¢/kWh but well below the high end of the interquartile range at 9 ¢/kWh; for low income programs the weighted average and median are close at around 7 ¢/kWh, but the high end soars to nearly 16 ¢/kWh; note that these are just the administrator cost and do not include the cost borne directly by consumers.
[257] See, for example: Gillingham, K., Newell, R.G., Palmer, K., *Energy Efficiency Economics and Policy*, Resources for the Future, April 2009.

the payback period exceeds how long a person intends to stay in a home, or when weighed against other types of investment. While EPA's 3% and 7% are commonly used "market discount rates" that might reasonably be applied to electric cooperatives themselves in terms of their administrative costs, there also appears a much higher "private discount rate" among residential consumers (and especially low-income households) that could conservatively range between 15% and 25%.[258] Assuming a 7% discount rate for the cooperative, this would give a blended discount rate for the administrator and the consumer of 11% to 16%.

These higher private discount rates mean that to overcome this reluctance or disinterest among residential consumers, electric cooperatives would have to spend far more on education, promotion, and incentives to even attempt to achieve the 1.5% annual savings goal EPA proposes, and even then there is no guarantee that customers will choose to adopt the offered programs at a rate sufficient to achieve these goals. As seen in the LBNL study, low-income consumers present an even higher administrative cost given the need to directly subsidize their limited ability to afford the upfront costs necessary for energy efficiency improvements.

One more area where EPA's costs estimates appear to be low is their "measure life" of energy efficiency investments. EPA assumes a 20-year life for efficiency improvements, but a review of several studies of energy efficiency effectiveness points to a much shorter measure life for many efficiency improvements, especially those involving lighting or HVAC rather than ventilation (*e.g.* insulation, duct sealing, etc.), whether due to either equipment failure or early retirement for other reasons.[259] Combined, the shorter measure life and the need for higher spending to promote adoption by residential and low-income consumers appear likely to drive up LCSE significantly.

NRECA believes that these higher cost assumptions for discount rates and retrofit costs are more realistic for the kinds of consumers served by cooperatives. The table below shows how these assumptions

[258] If, for example, a consumer making efficiency improvements on their home lacks the savings to cover up front costs but decides to put these costs on a credit card, they would face a 20% interest rate.
[259] GDS Associate, Inc., *Measure Life Report: Residential and Commercial/Industrial Lighting and HVAC Measures*, prepared for The New England State Program Working Group, June 2007. *Database for Energy Efficient Resources*, sponsored by the California Energy Commission and the California PUC, available at http://www.deeresources.com.

can increase the LCSE for cooperatives significantly above EPA's high-end estimate for generic utilities using a 7% discount rate and 20-year improvement life.

Table 3: Revised Estimates of Levelized Cost of Saved Energy for Electric Cooperatives Using Various Discount Rates, (¢/kWh, 2011 $)

	EPA High End LCSE	Co-op LCSE Including Revised Retrofit Assumptions		
Year	**7%**	**7%**	**11%**	**16%**
2020	10.3	13.7	16.9	19.3
2025	10.8	15.3	18.1	21.5
2030	11.0	14.6	17.2	20.5

vi. How will EPA and States account for situations where consumers do not adopt EE?

As just mentioned, even with incentives, the cost to consumers can be quite high, and in many cases the consumer will simply not choose to take action. Historically, EE programs have largely been voluntary and incentive-laden efforts, and particularly for residential EE programs, success of the program is based upon the consumer being willing to participate.[260] This often means the consumer has to make what are often substantial up-front investments in a product in the short-term, with the hope that over the long-term they will receive a greater savings. For example, a consumer would purchase a $1200 energy efficient refrigerator with an expectation that it will save them more energy over time compared to continued use of their existing refrigerator, or the purchase of a less expensive, less energy efficient unit. In this example, even if the State were to provide a rebate or tax incentive, the out-of-pocket expense may well exceed the potential savings. This choice can be much more difficult, if not impossible, for those with limited means.

Similarly, small businesses or even larger ones that face tough economic conditions such as the 2008 recession will focus all resources on keeping the business profitable and are unlikely to invest in a program viewed as adding to their short-term cost. Businesses and States tend to put EE programs on hold during tough economic times. When businesses are downsizing their work force and reducing shifts, it is much harder to justify expensive investments that do not pay off for many years. For States, tax revenue

[260] EPA acknowledges a series of barriers to the development of EE programs in their GHG Abatement Measures TSD, pp. 5-5 to 5-16.

from business and residences are down, which reduces the State's opportunity to provide tax incentives or grants and rebates that might make EE programs more attractive. All of these factors have been in play in recent years due to a slow and uneven recovery from the 2008 recession. So the energy efficiency gains EPA has noted during this period are likely driven more by reduced demand from idled factories, scaled back construction, and reduced customer spending rather than widespread adoption of energy efficiency programs.

Yet EPA's approach assumes that for EE programs, "if States build it," they will have a steadily increasing customer base that will adopt it. Based upon the EIA data of EE savings, it appears that in many States, that simply is not the case.

vii. EPA does not credit the low-cost EE that States have already implemented

EPA's 2012 baseline, and thus EPA's program, does not credit the reductions that most States have already achieved through EE programs, often at a significant cost. While most States are nowhere near achieving EPA's 1.5% annual savings goal, this does not mean that the States and regulated utilities have taken no action. As EPA noted, at least 48 States have some level of EE programs in place.[261] These programs take a concerted and considerable effort to launch and come at a high price. Both the States and their consumers will incur even greater costs if EPA does not account for the progress already achieved.

For example, when recommending the state scale back their EE program, Arizona Commissioner Gary Pierce discussed the increasing costs of their program as follows: "The rules were set up, and it was pretty easy at first to capture all the low-hanging fruit, but as we started reaching, these companies, because they are under an order to reach certain levels of energy efficiency, they were looking for stuff and trying to plug it in no matter what the cost."[262] By not crediting early action, EPA's approach will substantially increase the cost to consumers as the low-cost options have already been adopted.

This year, the Colorado Energy Office highlights that one of their EE programs, "Energy Performance Contracting" (EPC), has invested $447.4 million dollars ($88.96 per Coloradan) to "finance

[261] GHG Abatement Measures TSD, p. 5-16.
[262] Arizona Republic November 5, 2014: "Arizona energy-saving programs in jeopardy" by Ryan Randazzo

energy and water efficiency improvements with guaranteed energy savings."[263] Yet in spite of these laudable efforts, according to EPA's data, Colorado EE programs through 2012 had achieved only 0.84% annual savings and would still have a long way to go before they could even possibly achieve EPA's 1.5% goal.

NRECA believes that EPA needs to credit the early actions taken by States and permit states to adjust the state-level goals accordingly. Otherwise, States will decline to adopt such programs until they are required by law or regulation. In short, EPA's proposal will discourage, rather than encourage, future development of EE and other voluntary programs.

viii. EPA's method of equating end-use energy efficiency directly to greenhouse gas emission reductions is flawed

In its analysis, EPA consistently makes general assumptions that end-use reduction of kilowatt-hour energy consumption leads directly to specific levels of greenhouse emissions reductions in the power sector. The reality is that electrical end-use efficiency does not necessarily lead to emissions reductions, and certainly does not lead to the emission reductions assumed by EPA in its analysis. The problems of equating end-use electrical energy efficiency to an emission reduction are evidenced by the open questions that even the EPA poses about how to rectify fundamental disconnects in the relationship, such as – what if the efficiency is gained in a home or business that received electricity generated from a nuclear power plant, or wind, hydroelectric or solar power? What if the gains from efficiency improvements of a home or business (defined as more output per unit input) are used to increase output (heating or cooling for comfort) instead of to reduce input (electricity use)?[264] Surely in neither case would greenhouse gas emissions be reduced even though consumption is reduced in the first case and efficiency is improved in the second. An analysis with such fundamental open questions as these is not complete. Thus, basing state emission goals on the analysis is arbitrary and capricious.

[263] http://www.colorado.gov/cs/Satellite/GovEnergyOffice/CBON/1251597744880.

As the purpose of EPA's rule is to regulate GHG emissions, EPA has conflated the end-use electrical energy efficiency with greenhouse gas emissions in a way that breaks with the physical reality of energy production and use and the emission of greenhouse gas associated with electricity generation. The uncertainty that a specific end-use energy efficiency measure will lead to any emissions reduction at all depending on the electricity generation source and whether the consumer decides to spend the dividend from the efficiency on conservation or additional output or comfort shows that end-use energy efficiency is not a proper component of BSER.

ix. The erosion of the viability of EE reductions over time and incremental higher costs for EE after early actions and initial program implementation

EPA does not adequately address the risks of lack of persistence of the energy savings involved with energy efficiency programs. Once an energy efficiency measure is installed, there is a significant risk that the energy savings will not persist. Homes implementing energy efficiency measures can be remodeled and businesses can go under or change out their equipment for any number of reasons. In either scenario, equipment and appliances can be operated at different levels than anticipated, such as if new occupants are added or removed from a home, weather events cause changes in heating or cooling needs, or equipment is not maintained. All of these scenarios would lead to end-use efficiency measures not leading to the greenhouse gas emission reductions anticipated by EPA or utilities and outside of state control, and for that reason analysis based on the assumptions are flawed and the measures themselves are not BSER.

x. EPA ignores the significance of the "rebound effect" on achieving emission reductions

The rebound effect is acknowledged and then largely dismissed in EPA's proposal.[265] Generally speaking, EPA characterizes a 'direct rebound' as an improvement in energy efficiency that reduces cost and therefore boosts its demand, while an 'indirect rebound' reflects energy efficiency savings that are used elsewhere in the economy and may increase energy consumption. EPA doesn't explain how or if it accounts for the "rebound effect" in the Proposed Rule, but instead simply references several studies that find the

[265] GHG Abatement Measures TSD, p. 5-29.

rebound effect to be "relatively modest" compared to the importance of energy efficiency as an effective way of reducing energy consumption and CO_2 emissions.[266] This arbitrarily dismisses the potential impact of the "rebound effect" when EPA sets the state goals.

xi. Whether EE displaces coal vs. natural gas, nuclear or renewable energy generation

EPA seeks comment on how to account for the fact that EE programs may displace emissions from non-affected EGUs such as nuclear, gas or renewable units.[267] Implementation of effective EE programs that actually reduce demand for electricity results in a reduction of whatever generation provides their power. This means EE programs indiscriminately displace generation of any type, including EPA's preferred non-CO_2 emitting generation. As we mentioned earlier, EPA seems to ignore that impact when setting the state goals.

xii. EE programs adopted in one State while the affected generation load is in another State

Similar to the scenario discussed above in which energy efficiency measures do not necessarily equate to emissions reductions depending on the source of the electricity (such as if generation avoided is renewable generation), energy efficiency activities in any given geographic location (State) do not necessarily translate into reduced generation in the same location. The generation unit affected by a given energy efficiency measure may be located in a different State than the implemented measure. A State's inability to control the location of the impact of an efficiency measure on the GHG emissions within the State and the inability to address this issue without making arbitrary assumptions is indicative of the challenges associated with using end-use efficiency to control emissions and further indicates that it is not BSER.

xiii. Enforcement of an EE standard on utilities that have no control over the EE program

As described earlier in these comments, EPA and many of the state environmental agencies have no legal authority to require the development and implementation of EE programs. Further, as EPA describes

[266] *Id.*, pp. 5-28 to 5-29.
[267] 79 Fed. Reg. at 34,919.

in the proposal, these programs may be state-driven, utility-driven, or some combination of the two. Significantly, for purposes of compliance with EPA's proposal, many state-based EE programs are clearly outside the utilities' control, yet EPA suggests that States tie the reduction requirement to the individual utilities. If the utility does not have a role in developing or implementing an EE program, how can it be held accountable for achieving the reductions?

xiv. Protocols for evaluation, measurement, and verification (EM&V) of end-use energy efficiency for measuring compliance with 111(d) should be left to the States

When developing the proposal, EPA did not recognize or account for the inherent differences in EE programs and their EM&V protocols across the States. As discussed earlier, EPA arbitrarily evaluated a handful of States deemed by EPA to be leaders in EE deployment and determined that *all* States could achieve a 1.5% annual EE savings. EPA further assumed that the EM&V protocols in these same States could serve as guidance for other States in developing and measuring their programs. EPA should not assume these state EM&V protocols are the preferred method that other States need to follow.

The evaluation, measurement, and verification of energy *not used* can be overly cumbersome, confusing, and costly if the balance between costs and benefits of EM&V is not properly struck. Many of the measurement and verification practices for end-use efficiency used today were developed for for-profit utilities to ensure that energy efficiency cost (and profit) recovery is rigorously justified. Measurement and verification of energy efficiency projects to meet state goals should not be constrained to those methods employed in the IOU cost recovery paradigm. In the case of statewide programs, it may be most effective to monitor savings upstream of the consumer-utility relationship or at a higher level than some methodologies used by large IOUs that can require large sample sizes, rigorous statistical analysis, or in-home visits in some cases. Given that the cost of EM&V can be a barrier to energy efficiency program adoption, methodologies should be as simple as possible to meet the specific state or program need.

EPA should not assume certain state EM&V protocols are the preferred method that other States need to follow and should not limit future EM&V options to the existing energy efficiency paradigm, especially when compliance is based on greenhouse gas emissions levels, not the energy efficiency (kWh) metrics that existing protocols have been designed to measure.

EPA in fact noted that many States have taken steps to develop EE programs and protocols. In most cases, the individual State tailored their program goals, as well as the EM&V approach, to what made sense for their State. For example, cooperatives and other organizations involved in implementing energy efficiency programs are allowed to follow reliable estimates of energy efficiency savings by using existing technical reference manuals (TRM), program impact evaluation results, and other sources of deemed savings that are available from larger utilities or state government agencies. Where available, there are significant economies of scale and cost savings that can be achieved by using these existing data sources and EM&V studies.[268]

Any final rule must provide each State the flexibility to determine whether and how it might implement EE programs to meet its Section 111(d) obligations. Where States adopt EE programs, NRECA recommends that EPA and the States allow for unit-by-unit flexibility when adopting EM&V protocols to account for the various utilities, after consideration of their size, resources, and customer base. A NRECA-commissioned study in May 2012 indicated that only a handful of States require cooperatives to conduct EM&V studies or to report savings from EE programs. [269] It should be recognized that EPA's proposed plan would introduce a new paradigm under which energy efficiency could potentially be used to meet state GHG reduction targets. As such, the application of existing protocols developed by States for the existing paradigm under which energy efficiency is used to meet different goals may not be the most effective and appropriate. Therefore, it is critical that EPA not specify or mandate existing protocols for use by States and that EPA instead allow States flexibility to use methodologies that are most appropriate given their plans to the extent that they do or do not plan to use energy efficiency to meet their emission rate targets.

[268] https://www.nreca.coop/wp-content/uploads/2013/12/EMVReportAugust2012.pdf.
[269] *Id*.

Consistent with our position that States be given flexibility to adopt individualized EM&V protocols, NRECA recommends that EPA and States not require third party verification or certification of EE programs. These programs quickly become cost prohibitive and are unnecessary because, as mentioned above, numerous existing mechanisms have been developed that reflect best practices in designing EE program and their accompanying EM&V protocols. As needed, States can choose to draw on the best practices of other States to develop or enhance their own EE programs. Ultimately, depending on how their implementation plan is drafted, the States, their affected utilities, or both will be required to demonstrate compliance with any adopted EE program. The compliance requirement alone will ensure that they implement a program that can be adequately evaluated and verified. Adding third party verification would only increase costs of EE programs and the time needed to build them out, without providing any corresponding benefit.

As EPA develops guidance for EE programs, it should ensure States have flexibility to adopt EM&V protocols best suited to their specific needs. For example, NRECA and others worked to ensure that a Department of Energy initiative on measurement protocols would clearly distinguish the unique characteristics and needs of small utilities so that they would have a reasonable and cost-effective approach for developing EM&V without being required to adopt some of the large scale EM&V protocols identified by DOE. The DOE acknowledged this as the "small utilities protocol" and referenced the analysis completed by NRECA as follows:[270]

> ***Options for Small Program Administrators*** *UMP recognizes that even the lower cost options provided in the UMP protocols may be impractical where resources are constrained or programs are small (such as those offered by small utilities).*[271] *In these circumstances, program administrators may consider using deemed savings values from:*

[270] National Renewable Energy Laboratory, *The Uniform Methods Project: Methods for Determining Energy Efficiency Savings for Specific Measures* (April 2013), available at http://energy.gov/sites/prod/files/2013/07/f2/53827_complete.pdf. Note that this report was prepared when NRECA and others worked with the Department of Energy as they developed the Uniform Methodologies Project (UMP) M&V standards. In its UMP, DOE recognized the need States that develop EE programs will need to address small utility challenges. While UMP may not be appropriate for application in the context of this proposed rule for some states, it remains the specific costs and benefits of M&V to small utilizes must be considered separately.

[271] Additional information on the costs and benefits of different measurement and verification approaches for small utilities can be found in the *Analysis of Proposed Department of Energy Evaluation, Measurement and Verification Protocols*, sponsored by the National Rural Electric Cooperative Association available at: http://www.nreca.coop/issues/ElectricIndustryIssues/Documents/EMVReportAugust2012.pdf.

• TRMs created by regional or state entities
• Evaluations of similar programs performed by other regional utilities. (These can serve as the basis for determining energy efficiency savings, provided that the installation and proper operation of the energy efficiency measure or device has been verified.)

Deemed savings may be adjusted to allow for climate or other factors (regional or economic/demographic) that differ from one jurisdiction to another. Given the differences in how TRMs determine savings for identical measures, program administrators choosing this path should use deemed savings values based on calculations and stipulated values derived using the UMP protocols when possible. Those using this approach should update their deemed savings values periodically to incorporate changes in appliance and building codes and the results of new EM&V studies (such as the primary protocols developed under the UMP or other secondary sources). Alternatively, where possible, program administrators may consider other cost-saving measures, such as pooling EM&V resources and jointly conducting evaluations of similar programs through local associations. (This has been done successfully in small utilities in California, Michigan, and the Pacific Northwest.) Small utilities may also consider either coordinating with regional larger utilities or adopting the results of evaluations of similar programs implemented by larger utilities.

States that develop EE programs will need to address these small utility challenges. EPA and the States need to recognize that, with any EE program, the cost impacts on small utilities and their customers will likely be higher, while the benefits of the program will likely be lower. Allowing flexibility for these situations through adoption of measures akin to the small utilities protocols will be critical.

IV. The Proposed Rule is not only invalid, but is unworkable in its present form.

A. The time proposed for States' submissions is too short, and the final compliance date should be extended

EPA proposes to allow the States roughly one year from the finalization of the emission guidelines to submit their state implementation plans (SIPs) establishing and applying standards of performance to affected facilities within their jurisdictions. Although EPA proposes to allow extensions of up to a year for States proposing plans alone, and up to two years for States proposing plans in conjunction with other States, even these extended periods are impermissibly short given the complexity of the task at hand.[272] Section 111(d) specifically refers to Section 110 as a model for the adoption of SIPs addressing emissions

[272] Under the Proposal, a State may be granted a one-year extension if it submits an initial plan by June 30, 2016, that includes commitments for "concrete steps that will ensure that the state will submit a complete plan by June 30, 2017". States cooperating in and submitting a multi-State plan can seek a two-year extension – to June 30, 2018 – also by submitting an initial plan that meets the requirements set out in the previous sentence.

from existing sources in a category.[273] Section 110 allows States *up to three years* after promulgation of a NAAQS to submit SIPs.[274] Even this period of time does not appropriately reflect the complexity of determining how to obtain the required emission reductions and the time necessary to adopt the laws and regulations necessary to achieve them given this rulemaking's unprecedented scale and scope.

EPA should grant States at least five years to submit single state emission guidelines SIPs, and at least seven years to submit multi-state SIPs. Extensions should be liberally granted when a State can demonstrate that it is making good faith efforts to develop its plan or when it is working with other States to develop a multi-state or regional plan. The Proposed Rule would require States to take unprecedented steps to regulate the generation, transmission, and use of electricity within their borders and, in many instances, beyond them. These efforts are likely to require the passage of new legislation authorizing such actions, the development of regulations to implement those statutory authorities, and detailed assessments on a utility-by-utility, source-by-source basis of what reductions can be obtained while still ensuring a reliable and affordable electric supply for the States' citizens. Efforts to negotiate and implement interstate plans, or to convert a rate-based emission reduction goal to a mass-based reduction goal, are likely to be even more time-consuming, as action will be required by multiple States, as well as by RTOs that do not follow state boundaries. Given limited legislative calendars and the burdens already placed on regulators, each of these steps will take considerable time—far more than EPA has allowed even with extensions. This means, as well, that the final compliance deadline must be extended, from 2030 to at least 2035, to account for the more realistic timeframes NRECA urges EPA to adopt.

B. EPA's establishment of stringent interim goals undermines any flexibility for States or utilities to comply with the requirements

Even if state agencies can acquire the necessary statutory authority and somehow meet EPA's aggressive SIP submission deadlines – and assuming expeditious EPA plan approval – implementation of plans including most if not all four of EPA's building blocks will be difficult. As an example, even increasing heat rate efficiency of individual generating units cannot be accomplished in a short period of

[273] 42 U.S.C. § 7410.
[274] 42 U.S.C. § 7410(a)(1).

time. Attempting to meet the heat rate efficiency requirement for individual units will require engineering evaluation and design, and procurement and installation of parts and equipment. Completing this process for all affected generating units is very unlikely to be possible with a three-year or possibly shorter time frame, if plan submission or approval is delayed. And with several hundred units across the country engaged in the same process to improve heat rate efficiency at the same time will undoubtedly result in significant delays.

Even if individual States were able to adhere to the one-year plan submission deadline, and EPA approves plans within an additional year or by June 30 2017, barely two and one half years would remain prior to the 2020 interim goal deadline.

Meeting the 70% dispatch goal for natural gas-fired units is likely to require significant upgrades and modification of many such units to make them capable of operating at that level. To the extent that this is required for many units within a State, completing the needed upgrades and modifications within the short two and one-half year implementation period is highly unlikely.

Substantially increasing natural gas infrastructure to meet the goals, which will require adding new interstate and intrastate pipelines, will require significant time periods and financial investments. Adding pipeline capacity in time for the interim deadline is essentially impossible at this time.

Two new major interstate natural gas pipelines were announced this fall: the Atlantic Coast Pipeline to move gas from shale reserves in West Virginia, Ohio, and Pennsylvania to Virginia and North Carolina, and the Mountain Valley Pipeline to connect the Equitrans transmission system in West Virginia to the Transcontinental Pipeline in Virginia.

As proposed, the Atlantic Coast Pipeline project will be 550 miles long, carry approximately 1.5 billion cubic feet of natural gas per day, and span major portions of three States. An initial application for approval of the project is expected to be filed with FERC in the next few months, followed by a full application by the middle of 2015. Assuming quick review and approval by FERC by 2016 and start of construction later that year, the project would require three to five years for construction and operation, assuming no significant delays in acquiring rights of way for the route and equipment. At best, the project would be completed at approximately the same time as the interim deadline and not be likely to significantly contribute to measures needed to meet those goals.

The Mountain Valley Pipeline project will run for 330 miles and is projected to carry 2 billion cubic feet per day of natural gas. The project will also require FERC approval for construction and operation. Expedited review and approval by FERC would allow start of construction by 2016, with completion by 2019, assuming no significant delays in approval, rights of way, or construction. Once again, even with a current announcement of this project, the likelihood of its completion in time to support the interim deadline is extremely low.

The examples above are best cases, since they are at least well along in the planning stage. Any additional pipeline projects needed to meet requirements of the Proposal will be starting from this point forward or after state plans are crafted. This means they would almost certainly be unable to come on line by the interim deadline and would more likely be completed several years thereafter. Consequently, any interim goal requirements in the final Guidelines dependent on natural gas use and availability must be based solely on existing infrastructure and cannot be premised on construction of additional capacity since it could not be completed prior to the interim deadline.

Increasing the renewable energy sources in a State within such a short period would be highly unlikely due to the time needed to receive required regulatory permits and authorizations, design, contract for, and install the necessary equipment.

Often new transmission will be necessary to support added renewable energy sources. This takes years to plan and implement. In the East and Midwest, two recent examples of the time needed to add electric transmission lines occurred in Pennsylvania and Minnesota. In northeastern Pennsylvania, PPL Electric Utilities has proposed a new 500 kV line from Berwick, Pennsylvania, to the Roseland area of New Jersey, a distance of approximately 120 miles. As described by PPL in its 2008 announcement, the proposed new line is needed to handle increasing customer demand and prevent overloading the current grid system in a way that could result in blackouts of the PJM regional interconnection system. In its original filings with the Pennsylvania Public Utility Commission, PPL stated that this new capacity was needed by mid-2012 to avoid potential blackouts. Due to regulatory delays related to selection of the route for the line and other issues, construction of the line is still ongoing. PPL now anticipates that the line will be completed and in service by mid-2015 – three years later than the original schedule.

In Minnesota, ITC Midwest, a regional transmission company, has proposed a 345 kV electric transmission line to run approximately 73 miles from Jackson County, Minnesota, to several substations in northern Iowa. The line is subject to two separate regulatory approvals by the Minnesota Public Utilities Commission before it can be constructed – a Certificate of Need and a Route Permit – as well as regulatory approvals in Iowa. The draft Environmental Impact Statement for the proposed line was issued in March 2014, with public meetings and hearings following. Scoping meetings with the commission staff began in early 2013. Currently, the applications for the two approvals are pending before the Minnesota commission, with no deadline for decisions on them. If the approvals are both issued, construction of the line will require several years, assuming no significant delays in obtaining rights of way, acquiring equipment, or during construction. At best, the line will not be available for service earlier than 2018-2019.

As these examples highlight, existing transmission projects around the country take many years to complete, well beyond what could be reasonably expected to meet EPA's interim goal deadline. And these are electric transmissions projects that are well along in the planning and regulatory stages. New transmission needed to meet the requirements of the proposal could not be installed and operated until several years later and certainly not by 2020.

Similarly, constructing and operating additional nuclear generating units would be impossible within the time periods in the proposal. At a minimum, a time period of more than ten years is required to plan and obtain financing, obtain federal and state regulatory authorizations for the project, construct the plant, and commence operation.

A current example is the V.C. Summer Nuclear Station Units 2 and 3 project in South Carolina. The application for approval by the S.C. Public Service Commission (SCPSC) was filed in May 2008, following several years of planning and coordination with the staff of the commission. The application was considered by the SCPSC and an order approving the project issued in March 2009. The application anticipated commercial operation startup dates of April 2016 and January 2019, respectively. However, as of the most recent report to the commission in June of this year, engineering and construction delays have pushed the projected completion dates to early 2019 for Unit 2, with Unit 3 extended to early 2020. Assuming these extended dates are met, the time period from filing of the SCPSC application in 2008 to projected completion will be eleven years for Unit 2, and twelve years for Unit 3. And these time periods do not include the several additional years needed to plan, engineer, and craft necessary regulatory applications prior to 2008.

Duke Energy currently has a two-unit nuclear project application for a combined Construction and Operating License (COL) pending before the Nuclear Regulatory Commission (NRC) that clearly demonstrates the extended time period necessary to license, construct and operate nuclear generating units. The application for the W.S. Lee Nuclear Station near Gaffney, S.C., was filed with the NRC in December 2007. Duke originally anticipated that the two units would come into service in 2016-2018. However, the project has been repeatedly delayed. Most recently, the NRC announced that a final hearing on the COL application would not occur until 2016 due, in part, to limited agency resources. Assuming the hearing occurs in 2016, the COL is issued by 2017, and construction commences immediately, the units would still not come into service until at least 2023-2025. Consequently, they would not be available to provide non-GHG emitting generation until well after the 2020 interim deadline.

A recent, and untoward, example of lack of progress in adding nuclear (non-GHG emitting) generation is Duke Energy's cancellation of two proposed nuclear units, Levy 1 and 2, in Florida. Plans for the two units were announced in 2008, based on issuance by the Nuclear Regulatory Commission (NRC) of regulatory approvals by January 2014. The company cancelled the project last year based on the inability of NRC to issue the needed approval by that date. This example clearly demonstrated a typical time period required prior to issuance of regulatory approvals and start of construction – six years. Combined with the eleven and twelve year construction periods for the Summer project described above, this illustrates that a time period in excess of fifteen years to bring on additional nuclear generation as contemplated in the Proposal is more realistic.

Overall, the electric utility industry proposed more than two dozen nuclear reactors across the country, but only two major projects are under construction: one in Georgia and the V.C. Summer project in South Carolina. Thus, the timeline in the Proposal for additional nuclear generation to be added by States is entirely fanciful. Only nuclear units well along in the planning process or for which regulatory applications have been filed could be constructed and operated as part of a state plan prior to the 2030 final deadline.

Finally, even relatively simple energy efficiency programs require extensive evaluation, planning, regulatory authorizations and permits, creation of financial incentives, and construction or installation of new equipment to be fully implemented. As we highlighted previously, the energy efficiency programs of even the twelve best performing States have been in place for several decades and with three exceptions, none of them has achieved anywhere close to the 1.5% annual energy efficiency requirement EPA proposes. Clearly, a period of two and one-half years to ramp up the program, even allowing until 2025 as EPA suggests, is entirely insufficient to implement these build block components.

C. The Proposed Rule's tight implementation deadlines ignore forty-four years of Clean Air Act history

To attain the newly-established National Ambient Air Quality Standards,[275] Congress recognized, the 1970 Clean Air Act would require several years for States to implement. Thus, initial SIPs were to be implemented within three years after approval by EPA.[276] However in July 1976, EPA notified forty-five States that their SIPs were inadequate due to the failure to attain one or more of the standards. To remedy this situation, Congress, in the 1977 amendments to the Clean Air Act,[277] established new requirements and deadlines for States to submit revised SIPs to attain the standards. The new deadlines initially extended implementation deadlines for an additional five years to 1980 for submission and implementation of revised SIPs. However, also recognizing the intractable nature of two pollutants, carbon monoxide and oxidants,

[275] EPA established NAAQS for six pollutants in 1971: ozone, hydrocarbons, particulate matter, sulfur dioxide, nitrogen dioxide, and carbon monoxide.

[276] EPA's track record of reviewing and acting on SIP submittals belies the agency's assertion that it can and will act on plans under the Proposal within one year. Recognizing EPA's delays and failure to act on SIP submittals, Congress included an 18-month deadline for EPA action on SIPs in the Clean Air Act Amendments of 1990. Despite this deadline, EPA has been sued several times to compel the agency to act on pending SIP submittals.

[277] P.L. 95-95 CLEAN AIR ACT AMENDMENTS OF 1977..

Congress provided an additional five years to 1987 to attain the two standards.

Thirteen years later, Congress was again faced with the inability of all States to attain the standards, particularly for ozone, and once again extended the timelines for SIP submissions and attainment of standards. With the benefit of twenty years of experience since SIPs were originally required, Congress in 1990[278] established a five-level tiered system for SIP submittals and deadlines for attaining the ozone NAAQS based on the severity of the nonattainment.[279] For two of the lower tiers, Moderate and Serious areas, with relatively modest additional regulatory requirements, States were authorized three and four years, respectively, to submit revised SIPs to attain the standard.

Given the inability of States to attain the ozone standard, Congress set separate attainment dates for each tier. For Moderate and Serious areas, the new attainment dates were set at six and nine years, respectively, after enactment. For the most polluted areas, designated as Severe and Extreme, States were allowed ten years, or more, for submission of SIP revisions with attainment dates set at fifteen and twenty years, respectively, after enactment of the amendments.

The collective experiences of States and EPA working to attain air quality standards, and Congress' statutory recognition of the difficulties in each successive set of Clean Air Act legislation, highlights the folly of the extremely short timelines in the Proposed Rule. Under the statute, an Extreme area is authorized *twenty years* to attain a standard that it had already been working to reach for twenty previous years. By contrast, under the Proposed Rule all States have essentially the same very short timelines with no more than three years to meet unrealistic Interim Goals and less than fifteen year to meet the Final Goals. And these unrealistic timelines under the Proposed Rule are for reduction of CO_2 emissions, a pollutant that few States have any experience controlling. The history of the Clean Air Act described above clearly demonstrates how unrealistic the deadlines in the Proposal are.

A fundamental principle of cooperative Federalism under the Act is that state air pollution agencies are not acting as delegates of EPA authority or directly implementing the Federal Clean Air Act in

---

278 P.L. 101-549, CLEAN AIR ACT AMENDMENTS OF 1990.

279 From lowest to highest level of nonattainment, the five tiers are: Marginal, Moderate, Serious, Severe, and Extreme.

establishing their programs and requirements under Sections 110 and 111(d). Instead, they are acting and implementing EPA-mandated requirements derived from the Clean Air Act through organic state statutes. As such, they are governed by the statutory and constitutional principles of each State, subject to the limitations in such authorities as exist in each State. Some States may have no statutory authority to regulate CO_2 as a greenhouse gas, especially in the broad manner EPA dictates in its Proposed Rule.

Consequently, the extremely tight time schedules and deadlines in the Proposal – final rules by June 2015, with SIPs to be submitted by June 2016 (with limited opportunities for one- and two-year extensions[280]), and interim reduction goals to be met by 2020 – will be impossible for most, if not all, States to meet. In most States, legislatures meet for limited time periods during each year – if they meet annually. Other state legislatures meet every other year, further delaying those States' ability to meet EPA's unrealistic timelines.

Consistent with CAA Section 110, NRECA recommends EPA provide at least five years for individual States to develop implementation plans under 111(d) and seven years for States that choose to adopt multi-state plans. These time periods are necessary for States to fully evaluate compliance approaches, including modeling and additional technical analyses, obtain necessary statutory authority, draft and finalize implementation plans that are subject to notice, comment, and hearing administrative procedures. The additional recommended time will account for the significant coordination needed for state agencies to develop plans with other agencies with jurisdiction over aspects of the requirements under the Proposed Rule, and especially for the coordination needed among multiple agencies in States participating in multi-state plans.

EPA should also provide a sufficient time period for state legislatures to enact necessary legislation. The time allocated under the Proposed Rule is unrealistically short and will not provide the time necessary to enact the legislative authority needed to implement at least three of EPA's building blocks. At

[280] Under the Proposal, a State may be granted a one-year extension *if* it submits an initial plan by June 30, 2016 that includes commitments for "concrete steps that will ensure that the state will submit a complete plan by June 30, 2017". States cooperating in and submitting a multi-State plan can seek a two-year extension – to June 30, 2018 – also by submitting an initial plan that meets the requirements set out in the previous sentence.

a minimum, EPA should include at least two to three years for state legislatures to act, and extend that part of the implementation process to 2019.

Following enactment of state legislation, state regulatory agencies, both environmental agencies and public utility regulators, will require, at a minimum, 18 months to two years to adopt implementing regulations and draft plans, even on an expedited basis. Coordinating regulations among several state agencies under a multi-state plan will require additional time, at least two to three years.

For example, EPA frequently cites the Northeast States' formation of the Regional Greenhouse Gas Initiative (RGGI) as an example of how States can band together for collective action to comply with the Proposed Rule.[281] RGGI was not created overnight – as EPA would have States try to do under its proposal – but required many years to plan and implement. The initial effort began in 2003, with two years needed to craft a CO_2 emissions reduction plan for submission to participating States for review. An additional three years were required to establish the first auction of CO_2 credits in 2008. In this instance, with all participants voluntarily working towards a shared, and much more limited, goal than EPA imposed in its proposal, the project took five years to accomplish. Under EPA's proposal, even the RGGI program would not have had sufficient time to be launched.

Moreover, the outside-the-fence-line options and requirements in the proposal will, at a minimum, require direct participation by each State's public utility regulatory body. This results from EPA's inclusion of requirements for increased use of renewable energy and non-emitting electricity sources, dispatch of generating units based on CO_2 emission rates rather than traditional least-cost dispatch, and energy efficiency measures such as demand management. These measures are well beyond the jurisdiction and statutory authority of state air pollution agencies. In many States, these agencies have not worked together

[281] As originally established, RGGI was comprised of ten Northeastern States: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont, with New Jersey withdrawing in 2011. In withdrawing New Jersey, Governor Chris Christie declared RGGI to be an ineffective way to reduce CO_2 emissions, that "does nothing more than tax electricity, tax our citizens, tax our businesses, with no discernible or measurable impact upon our environment." (New York Times, page A20, May 27, 2011). Only seven States formed the original group, with three more joining later prior to New Jersey's withdrawal.

previously and under EPA's proposal will be imposing its own oversight over their respective roles and jurisdiction.

Thus, implementation of the Proposal, or anything like it, will require new legislation to authorize involved state agencies, both air pollution and public utility regulators, to devise and implement the types of measures in the proposal. In cases where electric generating companies subject to the proposal operate in more than one State or a State's electric generating system is part of a multi-state system, the complexity and types of regulatory structures needed to implement the requirements in the proposal increase exponentially. Consequently, serious questions arise as to whether multi-state implementation plans as prescribed in the proposal will prove practical or feasible.

Even if an individual State can surmount these statutory and legislative hurdles in the very limited time provided under the Proposal, unless EPA grants an extension each State would need to complete its plan for submittal within a year following issuance of final rules by EPA. This time period is woefully inadequate for a State to create a plan approvable under the proposal. The complexity of the measures in each of the building blocks means that each State will have to extensively evaluate all electric generating units within the State: (1) for opportunities to meet the 6% heat rate improvement required under building block 1; (2) to determine whether or not all natural gas-fired units are capable of being dispatched on a 70% basis; (3) for means and opportunities to add to the State's renewable energy unit portfolio; (4) to determine whether or not nuclear generating units are capable of operating on an increased usage basis; and (5) what options are available to decrease electricity usage through demand-side management or other energy efficiency measures.

EPA then has a year to review and either approve each plan, seek changes to it, or disapprove the plan and issue a Federal Implementation Plan in its place.[282] During this period, the relevant state agencies and the state legislature will not know whether their plan will be judged acceptable. Even if EPA reviews

[282] In the event that EPA issues its own plan to a State in lieu of the State's submittal, significant issues arise as to what entity would administer and implement the plan, whether EPA would attempt to do so – in the face of its own limited resources and statutory authorities under the Clean Air Act – or attempt to mandate that the State must implement the plan.

and acts expeditiously to approve state plans, the earliest approvals cannot likely occur until at least late 2016. This places state agencies in the position of being unable to begin implementing an approved plan until well into 2017, with interim compliance required barely three years later in 2020.

A significant additional complication is that many additional sources and entities beyond traditionally regulated electric utility companies would likely be subject to requirements under building blocks 2, 3 and 4 of the proposal.[283] In particular, independent power producers and other electricity suppliers that are generally not subject to public utility regulation by States would have to be brought into the regulatory scheme. Statutory and regulatory means to include these sources, and coordinate their activities under a state plan will have to be devised and the legislative authority to implement them enacted.

Meeting the 70% goal of building block 2 could require significant participation by entities, such as independent power producers and others that are not owners or operators of the coal-fired power plants that are the primary targets of the proposal. For the most part, they are not regulated by state public utility regulatory agencies and may not subject to state statutory requirements for traditionally regulated utility companies. In such cases, integration of additional electricity providers into a state 111(d) SIP will require new legislative authority and evaluation of the significant practical and legal issues involved.

Similarly, increasing renewable energy sources and generating under building block 3 involves many other types of companies that design, build, and operate these sources of electricity. In general, they are even more diverse and not currently under any sort of state regulation. Careful evaluation will be needed to determine how and whether to incorporate them into a state 111(d) SIP to effectuate this building block. Inclusion of such sources would require new legislative authority for state agencies.

[283] Examples include: building block 2, increased dispatch of natural gas-fired units, many of which are owned and operated by such non-utility entities; building block 3, increasing renewable energy and non-emitting electricity generating sources; and building block 4, energy efficiency measures to reduce electricity usage, including demand-side management.

A significant aspect of adding renewable, nuclear and other non-GHG emitting sources of electricity is the need for added transmission capacity[284] to deliver electricity generated by the sources to end users. Without adequate electric transmission capacity, any additional output from these sources would be unavailable to reduce the use of GHG-emitting generation sources.

With very limited exceptions, authorization and regulation of electric transmission lines is by state public utility regulatory bodies under each State's organic statutes, rather than the Federal Energy Regulatory Commission (FERC), which generally has regulatory jurisdiction over natural gas pipelines as discussed below. Thus, any new electric transmission would be subject to the limitations and variations of state laws. As an initial matter, the need for any new transmission line must be established to the satisfaction of public utility regulators, along with approval of a route for the line, cost, and other legal requirements. With frequent and often vociferous opposition in recent years to siting electric transmission lines, regulatory approval is often difficult to obtain and time-consuming. On average, transmission lines require at a minimum 5 to 7 years from conception to construction and operation. For example, Utah permitting guidance estimates a seven year process for a routine siting, permitting and construction of a new, 100 mile power line that crosses federal lands.[285] Similarly, the Southwest Power Pool, in comments to EPA states that an average of six years is needed for new transmission lines and often can exceed 8.5 years from design to construction.[286]

Finally, increasing efficiency of electricity usage under building block 4 will require an integrated structure that includes all electricity suppliers in a State to be effective. Once again, other, non-public utility electricity suppliers will have to be brought into and integrated into each State's plan. The is especially the case with this building block since goal of 1.5% reduction in electricity usage continues into the future on an annual basis, and is not simply a one-time requirement like the 6% heat rate reduction. As discussed

[284] In this discussion, electric transmission capacity refers to those portions of the national electric grid that transport electricity at high voltages over distances to load centers as distinguished from electric distribution networks that deliver electricity at lower voltages to end users.
[285] Utah Office of Energy Development, "Guide to Permitting Electric Transmission Lines in Utah," at iii, Figure ES-1 (August 2013), http://energy.utah.gov/download/reports/PermittingGuide_Final%20080913%20(cd%20ver).pdf.
[286] http://www.spp.org/publications/2014-10-09_SPP%20Comments_EPA-HQ-OAR-2013-0602.pdf.

previously, including all electricity providers in a demand-side energy efficiency program to meet this goal will require complex integration of each of these entities and new state legislative authority to do so.

For the reasons discussed herein, and as recommended above, consistent with CAA Section 110, NRECA recommends that at least five years be provided for individual States to develop implementation plans under 111(d), and seven years for States that choosing to participate in multi-State plans. These extended deadlines will provide additional time for the significant coordination needed for multiple agencies in several States to develop plan and for the necessary legislative authority to implement at least three of EPA's building blocks to be enacted. EPA should adjust State's final compliance goals accordingly.

The Proposed Rule also makes no provision for States that are unable, despite best efforts, to meet the final emission reduction goals by the final compliance year. The final emission guidelines should provide procedures under which States that have demonstrated their efforts to attain the emission reduction targets but have not achieved those targets by that deadline can request and obtain extensions of time within which to meet those targets. NRECA suggests that EPA should grant extensions of up to five years to applying States that demonstrate that they have been making good faith efforts to implement the guidelines and are on glidepaths to compliance.

EPA admits that the interim goal it proposes for NGCC is problematic, yet it requests comment on a proposed solution—a phase-in schedule for Building Block 2 goals based on the need for infrastructure improvements—that lacks any documentation to support it.[287] It is impossible for States to determine during the timeline provided what infrastructure will be required and how long it will take to plan, site, and build it. Therefore, it is impossible for States to determine now what phase-in schedule will be needed to meet EPA's targets. EPA thus commits the same basic legal and practical error in its NODA that invalidates its Proposed Rule: it imposes on its own, without statutory authority, universal standards of performance which, by statute, the States are supposed to set and are supposed to apply on a source-by source basis. Accordingly, NRECA reiterates its comment that EPA should (1) revise the Proposed Rule to allow States

[287] 79 Fed. Reg. 64,548-49.

to set the standards of performance, and to determine the extent to which, and the timing for applying those standards individually for each unit in its jurisdiction and (2) abandon the interim goals altogether.

EPA also requests comment on taking into account the book life of the facility and major upgrades when determining the timeline for attaining the interim goals.[288] Facility book life is an accounting metric that does not tell the whole story of a facility. Book life is merely the length of time an asset is depreciated for purposes of public accounting—typically around 30 or 40 years, unless the unit is subject to accelerated appreciation. A facility may have an additional 20 years of remaining useful life beyond the end of its book life. Basing the glidepath on book life thus does not account for circumstances where continued operation of the facility beyond the end of its book life is needed for system reliability. Furthermore, building book life into the glidepath will not necessarily protect facility owners from stranded investments. Facilities selling power into organized markets recover their capital investments according to market conditions, without a recovery guarantee. Operating units beyond the end of their book lives is therefore often necessary to recover investment capital. Future market conditions cannot be predicted, and so States will not be able to predetermine a glidepath for these units that ensures cost recovery. Even facilities that sell into unorganized markets, and thus may have some form of guaranteed return through a FERC tariff or state rate, may not be able to recover the costs of pollution control retrofits if these are not included in their respective tariff or rate.

For these reasons, EPA should abandon its unlawful effort to establish universal standards of performance and interim goals for existing units.

In addition to eliminating the interim goals, EPA must clarify the regulatory obligations associated with improvements. To the extent it continues to promote its proposed rule, EPA must make clear that heat-rate improvement projects undertaken to comply with the existing source emission guidelines are exempt from NSR as routine maintenance. Subjecting units to both this rule and NSR may result in economically indefensible decision-making, stranding of assets, and premature unit closures. Furthermore, since this process is state-directed, if modifications are likely to trigger NSR, the additional cost of

[288] *Id.*

compliance should be included in determining whether a unit can go forward with improvements. If, for example, viable heat rate improvements for a unit require the types of physical or operational modifications that historically trip new source review entailing significant additional expenditures, that should be a paramount factor in concluding that the implementation of the heat rate improvements is not feasible or is not cost-effective based on costs associated with new source review compliance.

EPA recognizes the risk that units implementing HRI will become subject to expensive, delaying NSR enforcement actions. For example, it notes this risk in its discussion of the potential for "rebound effects" resulting from HRIs achieved at individual EGUs.[289] It takes up the issue again in a section discussing the implications of the proposed rule for other EPA programs.[290] EPA appears to recognize that the kinds of HRI recommended to achieve the 4% to 6% HRI in Building Block 1 would reasonably be foreseen to trigger NSR review. It acknowledges that heat rate improvements at a unit could result in operating cost reductions making it economical to raise that unit's output. The increase in CO_2 emissions caused by the increased output could thus offset or outstrip the emission reductions achieved by the HRI, triggering NSR. Nevertheless, EPA maintains that flexibility afforded States by the other proposed Building Blocks—e.g., adjusting demand side measures and increasing renewable energy reliance—will enable them to avoid subjecting units within their jurisdiction to NSR.

EPA's assurances are contradicted by its enforcement history. The types of HRIs referred to in the Proposed Rule include upgrades to components such as soot blowers, boilers and boiler feed pumps, economizers, turbines, air and feedwater heaters, condensers, pulverizers, and condensate pumps, among others. Since 1999, EPA has targeted over 400 projects in NSR enforcement actions for making these kinds of upgrades as listed in Attachment K.[291] These actions can take more than a decade to litigate.[292] EPA has brought NSR actions against companies making efficiency upgrades where emissions resulting from

[289] Fed. Reg. at 34,858.
[290] *Id.*at 34928.
[291] *See* Attachment K.
[292] *See United States v. Cinergy*, 623 F.3d 455 (7th Cir. 2010); *United States v. Duke Energy Corp.*, No. 00-CV-1262 (M.D.N.C.); *United States v. Ala. Power Co.*, No. 01-152 (N.D. Ala.); *Pennsylvania v. Allegheny Energy, Inc.*, No. 05-885 (W.D. Pa.); *National Parks Conservation Ass'n v. TVA*, No. 01-71 (E.D. Tenn.).

increased output following efficiency gains are only *projected* to increase, regardless of whether they actually did. *See United States v. Ohio Edison*, 276 F. Supp. 2d 829 (S.D. Ohio 2003). EPA has even brought NSR challenges where emissions were projected not to increase as a result of efficiency upgrades. *See United States v. DTE Energy*, 711 F.3d 643 (6th Cir. 2013). Moreover, EPA and citizens have alleged an additional 600 projects have triggered NSR, as listed in Attachment L. [293] These projects as well were efforts to maintain or improve unit reliability and efficiency.

Nor are States going to be able to avoid triggering NSR by exercising the flexibility afforded them under the Proposed Rule, as EPA appears to suggest. As demonstrated elsewhere in these comments, the goals associated with other Building Blocks are likely not achievable for many States, especially those that are predominately rural and lack diverse generating units. EPA has thus proposed a rule that likely will result in the Agency suing the very entities that implement it. Baldly asserting that States will avoid this absurd result by implementing theoretical Building Blocks that many States lack the ability to implement will not protect companies seeking to implement Building Block 1. The logical and appropriate remedy is for EPA to amend its proposed rule to exempt from NSR all unit projects undertaken for HRI purposes.

D. Reliability will be Threatened if EPA Retains the Interim Compliance Goals

Individual States as well as regional transmission authorities are also raising significant concern over EPA's interim compliance goals. The changes to individual plants, transmission and pipeline infrastructure, and the function of state and regional power markets will all necessitate much more time than EPA allocates by imposing 2020 as the interim compliance goal.

For example, the Southwest Power Pool (SPP) has met with NRECA and other stakeholder groups, and it has provided comments to EPA stating that the interim compliance goals cannot be met. On October 9, 2014, the SPP submitted comments to EPA stating that the Agency is 1) not providing sufficient time to make the changes that will be required by EPA's rule, 2) that reliability will be adversely impacted, and 3) the rule will have material impacts on market-based dispatch of EGUs within the SPP.[294] Among other

[293] *See* Attachment L.
[294] *Supra* note 286.

recommendations, SPP says that more time is needed to meet the compliance goals. SPP further states that without the added time to make the transmission and generation capacity changes, grid reliability could be overloaded in portions of six States and may well be severely overloaded in portions of three of those States.[295]

Yet EPA claims to provide significant flexibility for States in choosing when and how to achieve BSER through its four building blocks. As EPA states:

> We also note that a state is not required to achieve the same level of emission reductions with respect to any one building block as assumed in the EPA's BSER analysis. If a state prefers not to attempt to achieve the level of performance estimated by the EPA for a particular building block, it can compensate through over-achievement in another one, or employ other compliance approaches not factored into the state-specific goal at all. EPA has estimated reasonable rather than maximum possible implementation levels for each building block in order to establish overall state goals that are achievable/while allowing states to take advantage of the flexibility to pursue some building blocks more aggressively, and others less aggressively, than is reflected in the goal computations, according to each state's needs and preferences.[296]

However, by imposing interim goals to be met by 2020, States, and the regulated entities under the Guidelines, will be required to achieve at least two-thirds of the reductions within at most two to three years after State plans are approved.[297] EPA claims states and the regulated community will have sufficient time to understand the requirements and begin implementing them, which apparently assumes they would take action prior to the state plans being finalized and approved. To justify this approach, EPA states that affected sources "will have knowledge of state requirements as they are adopted" and will therefore have more time to act.[298]

Regardless, the requirement for States to develop and implement interim goals, including "achievement demonstrations," imposes substantial cost and timing burdens on both the States and the regulated community.[299] Further, the tight timeframe for meeting the interim goals largely negates the opportunity for States to develop any reasonable alternatives to EPA's approach, thereby eliminating any

---

[295] *Id.* p. 6.
[296] 79 Fed. Reg. at 34,904.
[297] *Id.* at 34,905.
[298] *Id.*
[299] *Id.* at 34904.

flexibility for States and affected facilities. This will force shutdowns of many coal-fired power plants as the only means of achieving interim goals in such a short time frame. These plants will often have a useful life that extends well beyond the 2030 compliance deadline, and EPA's guidance must be revised in a way that assures the States and utilities have the ability to keep these plants economically viable.

For example, the Arizona Department of Environmental Quality (ADEQ) has already notified EPA of the significant challenges it faces. On August 22, 2014, ADEQ documented that EPA's interim goals remove any flexibility for the State to comply with EPA's guidelines.[300] Arizona's emission reduction of almost 52% is already one of the most stringent under EPA's proposal. EPA compounds the challenge faced by Arizona and its coal-fired utilities by requiring over 95% of their reductions by the interim compliance goal of 2020. This leaves the State with little choice but to shut down coal-fired capacity and dispatch natural gas (Building Block 2), as the expected ramp up and utilization of either Building Blocks 3 or 4 would occur too late to meet the 2020 goal. Compounding this, the ability of Arizona to meet the 2020 interim goal rests solely on Building Block 2, as improvements to heat rate efficiency would be of no consequence if the units are shut down. Furthermore, the utilities would have no business case to install expensive upgrades if they are to be shut down anyway.

While EPA suggests States should begin to ramp up energy efficiency requirements by 2017, which would likely precede the time when many States receive EPA approval of their plans -- as described above -- States will be unlikely to have legislative authority in place for several of the building blocks and, at most, only have authority over building block 1. That leaves most States with only the option of forcing fuel switching from coal over to natural gas for baseload power plant – assuming they even have the natural gas available and infrastructure in place to make such a sudden and dramatic change. As described by the State of Arizona, this would create complications of needing an uninterruptable supply of natural gas, pipelines and storage and enough sufficient available NGCC units to make up the difference in electric generating capacity.

[300] Steve Burr, ADEQ, email to EPA's Deborah Jordan and Colleen McKaughan 8/22/14, Attachment J.

Most of the merchant plant generators have current contracts with in-state and out-of-state entities, and Arizona has no control on how the units would be dispatched. ADEQ explains that building new NGCC units imposes siting and permitting requirements that average 10 years, or more time if federal lands are involved. Thus, no short-term solution is available and certainly would not be available in time to meet EPA's interim goals.

With these limitations or inability of these types of generation and infrastructure to meet the timeline in the proposal, EPA should remove the interim compliance goals. The focus of any final 111(d) Guidelines should be primarily on meeting the final compliance deadline.

As described in these comments, many coal-fired units will have useful lives that extend beyond the 2030 deadline. While the 2030 deadline for compliance is less unrealistic than the 2020 interim deadline, it still may not allow States with higher reduction goals to achieve them without significant coal-fired power plant shutdowns. Even then, with all of the statutory, regulatory, and practical changes needed to implement a set of requirements as sweeping as the proposal, all involved – States, public utility companies, and other entities subject to proposal requirements – face substantial challenges in meeting the ambitious goals of the Proposal.

E. EPA should identify in this rulemaking both the nature and the scope of the federal implementation plans it would prescribe where a State fails to submit a satisfactory plan

Section 111(d)(2) of the Clean Air Act gives the EPA Administrator the authority to issue a "federal implementation plan," or "FIP," if a State-submitted SIP is unsatisfactory and to enforce the FIP provisions if a State fails to do so.[301] In crafting a FIP, the EPA must consider the same factors Section 111 permits States to consider when crafting their SIPs, including "the remaining useful lives of the sources in the category of sources to which such standard applies."[302] One of the problems States will encounter in crafting their SIPs is the lack of clarity in the Proposed Rule concerning how and to what extent States are to

[301] 42 U.S.C. § 7411(d)(2)(A), (B). In the event that EPA issues its own plan to a State in lieu of the State's submittal, significant issues arise as to what entity would administer and implement the plan, whether EPA would attempt to do so – in the face of its own limited resources and statutory authorities under the Clean Air Act – or attempt to mandate that the State must implement the plan.
[302] 42 U.S.C. § 7411(d)(2).

consider the “remaining useful lives of the sources” and “other factors” while crafting SIPs that have a chance of being approved. It would be helpful for the EPA to promulgate in the Final Rule a model plan that will be deemed minimally acceptable for approval. Specification of the general terms of a FIP that it would issue to replace an unsubmitted or unsatisfactory SIP would provide much-needed guidance on the minimum elements of state plans that must be included for such a plan to be approved.

The Proposed Rule contains no model state plan and not even the broadest outline of what EPA believes it could lawfully prescribe in lieu of a submitted or acceptable state plan. This glaring absence is a conspicuous failure of the rule as it has been proposed. It leaves States guessing as to what aspects of the proposed existing source emission guidelines EPA believes it could prescribe under the Act if it were acting in the shoes of a State. EPA should therefore provide the States and regulated community with its views on the nature and scope of such a plan so that the States may be guided by the EPA’s assessment of what the law Clean Air Act allows with respect to considering the “remaining useful life” of sources and “other factors.”

EPA should therefore issue a supplemental notice of proposed rulemaking in which it specifies, and invites public comment on, the common elements of the federal plan it would prescribe if a State failed to submit a satisfactory plan. This should include, among other things, identification of each of the four Building Blocks EPA would expect to include in a federal plan and the legal rationale for them, discussion of how EPA would calculate a State’s emission reduction goal under a FIP, and how EPA would, in crafting such a plan, take into consideration the various factors, including the remaining useful life of the regulated sources, the Act requires it to consider.

F. EPA’s proposal would constitute a regulatory taking for which compensation would be required

Both the statute and the practicality of regulating existing sources impose additional limitations on the factors EPA may consider in determining BSER. Under the Clean Air Act and its accompanying regulations, performance standards and emission guidelines must be based on a BSER that is “achievable” in light of considerations such as cost and energy usage. However, even the most conservative measures prescribed in the Proposed Rule—e.g., heat-rate improvements and co-firing of renewable energy sources—will make plants operated by many of NRECA's members economically unsustainable. This is particularly true to the extent EPA considers reductions in operating capacity or frequency as components of BSER. Under the limitations that would result from such treatment, many units owned and operated by NRECA's members would be prevented from operating with sufficient frequency to generate the revenues required to service their existing debt. Even if a unit were not altogether prohibited from operating during specified periods, it is likely that diminished productivity caused by EPA's definition of BSER would make it commercially infeasible to maintain a particular unit. The result is a standard that not only disregards the "remaining useful life" of the unit, but also prescribes requirements that, by definition, are not "achievable" by many NRECA-member-owned units.

The forced retirements following adoption of the Proposed Rule would not be limited to aging units. On the contrary, several NRECA members have recently completed construction of state-of-the-art facilities, equipped with the latest pollution-control technologies. Seminole Electric Cooperative, for instance, has invested more than $530 million in environmental control technology and recycling practices, $260 million of which was placed into service less than 5 years ago. Even these units might be unable to meet the requirements established under EPA's proposed definition of BSER. The effects of the Proposed Rule could be so prohibitive as to be a taking requiring government compensation. Courts consider three factors to determine whether a regulation constitutes a compensable governmental taking: (1) the economic impact of the regulation on the property owner; (2) the extent to which the regulation interferes with the property-owner's distinct investment-backed expectations; and (3) the character of the government's invasion of the property owner's property interest.[303]

It is possible that the effects of the Proposed Rule are so severe that all three factors would support a finding that the proposed rule is a compensable taking. The regulation could force many facility owners to shut down their plants altogether, leaving them with parcels of worthless land blighted by useless power

[303] *See Lingle v. Chevron U.S.A. Inc.*, 544 U.S. 528, 538-39 (2005); *Connolly v. Pension Benefit Guarantee Corporation*, 475 U.S. 211, 224-25 (1986) (same).

plants and pollution-control equipment. The Proposed Rule would also completely upset utilities' investment-backed expectations by denying them the use of their investments. NRECA's members have each spent hundreds of millions of dollars on their facilities, making improvements and installing the latest pollution-control technologies. They have made these investments for the sole purpose of continuing to sell electricity in compliance with EPA rules that were promulgated pursuant to Section 112. The Proposed Rule could make it impossible for a number of even the most modern, up-to-date facilities to continue doing business, squandering the money invested in these facilities. This deprivation could be so severe as to be equivalent to a physical appropriation of the owners' property interests. Even if the land retains some of its residual value, hundreds of millions of dollars invested in the pollution controls and technological improvements will be rendered just as worthless as if they had been physically appropriated. EPA should thus carefully consider the risk of takings liability the Proposed Rule might trigger.

V. EPA must adopt a dynamic reliability safety valve that provides the States the flexibility they need to ensure reliability

In the Mercury and Air Toxics Rule, EPA recognized that overly aggressive schedules for implementation could undermine the reliability of the electric utility sector. EPA wisely provided in that rule for a reliability safety valve under which utilities could seek an additional year in which to implement the rule without running the risk of an enforcement action. EPA should recognize that this rule too poses risks to reliability and that a safety valve provision is therefore a critical component of any final emission guideline.

All of the FERC Commissioners who have spoken publicly concerning the Proposed Rule have supported consideration and/or adoption of a reliability safety valve. Chairman LaFleur stated in response to questions from the House Subcommittee on Energy and Power, "I would support a carefully designed mechanism to consider reliability if an issue arises. FERC is prepared to assist the EPA with reliability topics as we have in the past, and one approach might be to focus such a mechanism on multi-state aspects of compliance, to ensure that individual state plans do not conflict in ways that might pose reliability problems." Commissioner Bay stated, "I believe that a reliability safety valve should be considered by the

EPA." Commissioner Moeller stated "I am absolutely supportive of a reliability safety valve." Commissioner Clark explained, "I would support a reliability safety valve. One way to effectuate a safety valve would be to ensure that no state, federal, or regional implementation plan shall take effect until such time as FERC certifies that the implementation plan, taken together with other implementation plans, will not have a detrimental effect on bulk electric system reliability. In making its certification decision, FERC would need to employ an open and transparent process, and avail itself of information that resides with institutions such as the North American Electric Reliability Corporation and the various regional planning entities and RTOs/ISOs."[304]

The ISO/RTO Council (IRC) and the Southwest Power Pool have also asked for a safety valve. The IRC proposed a reliability safety valve (RSV) under which system operators would work with States and relevant reliability regulators prior to finalization and approval of a SIP to identify reliability issues and solutions, provide for regulatory review and approval of the assessment and solution, and then "accommodate the reliability solution under the CO_2 rule and/or SIP by providing for appropriate compliance and/or enforcement flexibility while a long-term reliability solution is developed and implemented.

In explaining the need for a reliability safety valve, Lanny Nickell, SPP's vice president of engineering, explained that "If the CPP compliance period begins before generation and adequate infrastructure can be added, the SPP region will face a significant loss of load and violations of regulatory reliability standards."[305] He added that it can take up to 8.5 years to plan, design, and build the transmission infrastructure needed to meeting changing generation resources.[306] According to the SPP's impact assessment, its transmission system could face severe overloads that will lead to cascading outages.

[304] Note that Commissioner Clark also stated that "because reliability and cost are so intertwined, I believe an important part of a reliability safety valve would be an associated cost safety valve, so that the impact on both reliability and cost could be considered as a package."
[305] Southwest Power Pool Press Release, *SPP assesses Clean Power Plan, says more time is needed to implement*, available at http://www.spp.org/publications/Clean%20Power%20Plan%20Report%20100914.pdf.
[306] *Id.*

For these reasons, in addition to asking EPA to extend the time for developing SIPs and to eliminate the interim goals, NRECA also asks EPA to permit States to stage the implementation of the rule out past 2030 as necessary to recognize a number of factors including reliability and the remaining useful lives of existing EGUs. And like FERC and the Transmission Operators who are responsible for keeping the lights on in their regions, NRECA also asks for a reliability safety valve that ensures that States are not forced to adopt SIPs that could undermine the reliability of the bulk electric system.

Unfortunately, a safety valve applied at the time that SIPs are drafted and approved is unlikely to be adequate to preserve reliability. Unlike with the mercury rule, compliance with the Proposed Rule doesn't revolve around the one-time installation of discrete technological fixes to specific power plants. Thus, merely pushing out the dates for designing SIPs and for demonstrating compliance, as the MACT reliability safety valve did, would be inadequate to maintain reliability in this context of this proposal. Nor are static reviews of the multi-state reliability impacts of SIPs at the time the States begin to implement them likely to be adequate in light of conditions on the grid at that time.

EPA must also give States the opportunity to adjust their SIPs *dynamically* in response to changes in the electric grid that at the time of original SIP development are not foreseeable. The IRC recognized this in proposing that "the final rule should allow for the use of a "rolling" RSV process to assess system reliability on a prospective basis at multiple states both prior to the SIP being finalized and approved and at various steps during its implementation, as necessary.

This kind of ongoing assessment and flexibility is essential because the proposed rule has an unprecedented scope and degree of complexity. It requires a wide range of entities to take action over a long period of time, including but not limited to FERC, the Nuclear Regulatory Commission, federal resource agencies responsible for permitting new electric and gas infrastructure, state legislatures, state regulators, state-regulated utilities and a wide range of non-state-regulated entities including transmission owners and operators, regional transmission entities, gas producers, owners of gas storage, gas pipelines, independent power producers, providers of energy efficiency services, and financial entities.

Moreover, the States' and EGUs' ability to comply with the Proposed Rule, and to maintain compliance with it, depends on an unusually broad range of conditions that are completely beyond the States' and EGUs' ability to control. The resources on the grid and their ability to serve consumers' energy needs change dynamically in response to intentional and unintentional changes in grid architecture, changes in market design and market conditions for the different participants, changes in technology, fires, floods, ice storms, and even economic growth and contractions. By defining the "best system of emissions reductions" to encompass the whole electric system, the EPA has made compliance dependent on all of those changing factors. For example:

- A State whose SIP relies heavily on efficiency improvements at existing coal plants could find compliance stymied by a number of factors that undermine those efficiencies, such as new environmental requirements that impose parasitic loads on the plant and changes in plant dispatch as a result of market rules or market outcomes that reduce the efficiency of the plant.
- A State whose SIP relies heavily on the completion of a new nuclear unit could find compliance stymied by changes in NRC regulations, changes in the availability of financing, changes in the market value of the new nuclear unit, or even an accident that significantly delays completion of the nuclear plant. The State would be forced to rely on more emitting resources to provide reliable electric service to consumers.
- A gas, nuclear generator or other low-emitting resource on which a SIP relies could suffer a severe breakdown that requires months or years to fix – forcing the State to rely more heavily in the meantime on higher-emission resources. This is what happened in California with the San Onofre Nuclear Generating Station (SONGS) suffered a major breakdown. SONGS never reopened;
- A gas generator on which a SIP relies could lose access to gas needed to operate because of a major breakdown in the pipeline that serves it that could take months to fix – forcing the State to rely more heavily in the meantime on higher-emission resources.

- A non-state regulated owner of a gas generator, nuclear generator, or other low-emitting resource on which a SIP relies could be forced to reduce its output because of transmission congestion caused by damage to a major element of the transmission system or changes in the locations of major generation and load on the transmission grid, or simply to changing transmission loading patterns resulting from significant changes in dispatch of generation resources. The State would be forced to rely more heavily on higher emitting resources until the congestion is relieved, which could take months or years.
- A non-state regulated owner of a gas generator, nuclear generator, or other low-emitting resource on which a SIP relies could choose to shut down the generator because it is not economic in the market due to increases in fuel prices, increases in fuel transportation costs, loss of a major customer, decreases in competing higher emitting fuel prices, or a range of other changes in wholesale market design and market outcomes that the State cannot control. The State would be forced to rely more heavily on higher-emission resources until a new lower-emitting resource could be built. But, if the market fundamentals are not there to support the lower-emitting generator that shut down, they may not be there for a new resource.
- Market prices for power could drop to such a degree and/or the uncertainty of cost recovery could rise to such a degree that the financial community might be unwilling to provide financing for new low-emitting resources on which a SIP relies. The State would be forced to rely on higher-emitting resources until market fundamentals change to the point required to attract capital back into generation investments.
- A State with a mass-based SIP could experience significant economic growth and thus significant load growth. That State would be forced to dispatch more power from emitting resources to meet the new demand reliably. No one predicted the level of economic and load growth that developments in oil recovery would have on North Dakota. We cannot predict what changes in technology or the economy will cause similar growth elsewhere.

- A State that relies heavily upon energy efficiency in its SIP could be stymied by new plug loads that increase per capita energy demand, such as electric vehicles or new high-demand consumer electronics. Notwithstanding extraordinarily high investments in energy efficiency, the State could be forced to dispatch more power from emitting resources in order to meet the new demand reliably.
- A State that relies heavily upon energy efficiency in its SIP could be stymied because the physics of the system and/or the operation of the wholesale market could cause the energy efficiency – to a significantly unanticipated degree -- to displace lower emitting resources more than higher emitting resources or to displace primarily generation in neighboring States. The effect of the energy efficiency on other resources is likely to change dynamically over time as the nature, location and economics of generation, transmission, and loads change.
- A State that relies heavily upon renewable energy investments in its SIP could be stymied because the physics of the system and/or the operation of the wholesale market could cause the renewable resources – to a significantly unanticipated degree to displace lower emitting resources more than higher emitting resources or to displace primarily generation in neighboring States. The effect of the renewable energy on other resources is likely to change dynamically over time as the nature, location and economics of generation, transmission, and loads change.

The States ought to be considering the availability, dispatchability, and emissions impacts of different emissions control approaches in developing their SIPs. But, as noted above, these factors are interdependent across the electric system and change dynamically. If EPA does not permit States to amend their SIPs and their compliance goals dynamically as the system changes – and thus as the best system of emissions reductions available to the States changes – EPA will force the States to choose between compliance and reliability, economic growth, and technological innovation. States and EGUs could face EPA compliance penalties and citizen suits due to factors entirely beyond their control. EPA cannot permit that result.

VI. Translation of emission rate-based CO_2 goals to mass-based equivalents

EPA's recent notice of additional information regarding the conversion of rate-based CO_2 goals to mass-based equivalents illustrates two methods for converting rate-based goals to mass-based or tonnage-based limits: one for existing sources and another for both existing and new fossil-fired sources.[307]

A. EPA's proposed methods can only serve as guidance to states and not requirements

The notice is unclear as to whether in EPA's view the proposed methodologies would be mandatory or optional if finalized. On one hand the notice states that the two methods are "illustrations of two potential options" that States may choose.[308] On the other hand, the notice also states that methodologies employed in translating a rate into a mass goal must achieve "…the equivalent in stringency."[309] The proposal's requirement that a State's rate-to-mass conversion must result in tonnage limits "equivalent in stringency" to that determined under the proposed methodologies indicates that, in EPA's view, methods a State employs cannot diverge from the methods described in the referenced technical support document (TSD), [310] because otherwise the calculated tonnage goal would be inconsistent with the calculations required by the TSD and possibly not as "stringent." Consistent with our earlier comments on EPA's authorities under Section 111(d), the methodologies proposed here can only serve as guidelines for States and cannot be binding on States. EPA cannot displace authorities granted States under section 111(d) to establish performance standards. The establishment of a tonnage goal based on EPA-selected methodology would thus unlawfully usurp state authority and discretion.

B. EPA proposed methods are inconsistent with methods utilized to determine state rate-based goals and are otherwise arbitrary.

EPA's proposed methods employ a hallmark of arbitrary rulemaking, because the underlying presumptions are inconsistent with those employed in the determination of state rate-based goals. For the denominator, the rate goal computation essentially incorporates the projected future sum total of all the

---

[307] 79 Fed Reg. 67406.
[308] *Id.* at 67408.
[309] *Id.* at 67407.
[310] Translation of the Clean Power Plan Emission Rate- Based CO2 Goals to Mass- Based Equivalents, Docket ID No. EPA-HQ-OAR-2013-0602

MWhs of all the sources in Building Blocks 1-3, as well as the MWhs associated with energy efficiency measures, while backing out the MWhs associated with future projected loss of coal-fired dispatch in the numerator. The result is a maximization of goal MWhs and a minimization of CO_2-based MWhs resulting in a stringent rate-based goal.

However, the proposed method to convert a rate-based to mass-based goal employs presumptions that are opposite of those employed in the goal computation. Here, EPA's proposed method backs out non-CO_2 based MWhs that are included in the rate-based goal computation, yielding a mass-based computation process that would *always* result in fewer tons in a rate to mass conversion than if the MWhs in the rate-based goal computation were utilized instead.

The most straightforward approach that is consistent with the method used in the goal calculation for a rate to mass conversion is to use the product of the goal-computed MWHs (the denominator) and the goal-calculated CO_2 rate/ MWh.

C. EPA cannot mandate tonnage rates for new fossil fuel sources

As discussed earlier in these comments, EPA cannot regulate new sources as existing sources under Section 111(d). Thus, to mandate tonnage limits on for new fossil fuel sources as part of a Section 111(d) plan, as EPA proposes in its new source rate to mass-based methodology, is plainly unlawful.

VII. Additional Responses to Specific EPA Requests for Comment

NRECA believes it has responded to most of the pertinent specific EPA requests for comments previously in this document, and we have endeavored wherever possible to identify the requests to which our comments are responsive. In this section, we respond to a few remaining specific requests on which NRECA has views or pertinent information for the Agency to consider.

A. Five Year Alternative, Monitoring and Compliance of Performance Goals.

EPA requests comment on the milestone approach and emission performance checks against projected performance in state plans in the context of the alternative 5-year performance period and the planning approach for alternative state goals that would include projections demonstrating that emissions performance would continue for up to ten years beyond 2030, and also whether EPA should establish BSER based on state performance goals for affected EGUs that extend further into the future.[311]

NRECA's Response: Where actual emissions exceed the performance goal due to unanticipated circumstances such as economic conditions, severe weather, or necessary postponement of planned retirements, the State or individual utility performance goal, as the case may be, should be adjusted accordingly with no penalty attached. Should the actual emissions only modestly exceed the performance goal without the influence of intervening unanticipated factors, no corrective measures should be required so long as a State is reasonably close to its performance goal.

Further, EPA lacks legal authority under Section 111 to establish a subsequent BSER based on levels of improved performance. Specifically, Section 111 does not permit EPA to reestablish a second BSER or performance goal. EPA refers to the eight-year review provision in Section 111(b) as authority to re-issue NSPS for existing units.[312] This view is misplaced, however, because EPA cannot re-issue a NSPS for new sources that have already gone through the process. Likewise here, existing sources that undergone a section 111(d) process cannot be forced to undergo it again.

B. Five Year Alternative, Maintenance vs. Improvement.

In connection with the alternative state goals, for the years after 2027, EPA requests comment on the same 'out-year' issues and concepts for maintaining or improving emission performance over time that are described for the final goal. Specifically, whether a state plan should provide for emission performance after 2025 solely through post-implementation emission checks that do not require a second plan submittal, or whether a State should also be required to make a second submittal prior to 2025 to demonstrate that its programs and measures are sufficient to maintain performance meeting the final goal for at least 10 years? What would be the appropriate date for any second state plan submittal designed to maintain emission performance after the 2025 performance level is achieved?[313]

[311] 79 Fed. Reg. at 34,907-08.
[312] 79 Fed. Reg. at 34,908.
[313] 79 Fed. Reg. at 34,909.

NRECA's Response: As stated above, EPA lacks legal authority under Section 111 to establish a subsequent BSER based on levels of improved performance. Specifically, Section 111 does not permit EPA to reestablish a second BSER or performance goal. EPA refers to the eight-year review provision in Section 111(b) as authority to re-issue NSPS for existing units.[314] This view is misplaced, however, because EPA cannot re-issue a NSPS for new sources that have already gone through the process. Likewise here, existing sources that have undergone a section 111(d) process cannot be forced to undergo it again.

Second, the only legally permissible alternative is post-implementation emission checks. When goal exceedances arise due to unforeseen circumstances, goals should be adjusted accordingly. For other exceedances, post-implementation checks coupled with state readjusted plans are appropriate.

C. Trading Programs.

EPA solicits comment on whether any of prior or existing trading programs like RGGI or emissions averaging should be considered as the BSER.[315]

NRECA's Response: Trading and/or emissions averaging approaches should not be considered as the BSER. The BSER on which a Section 111(d) standard of performance is based can only derive from reductions that are attainable "inside the fence" *at the affected source*. Once the performance standard is set, the affected utility may, with state approval, exercise flexible options to satisfy its obligations to reduce CO_2 emissions. This could include emissions averaging or offsetting among affected EGUs or with other generation sources, as well as other actions. In no case should a State be required to achieve emission reductions that exceed those required by aggregating individual EGU obligations within the State; nor should an EGU be obligated to achieve reductions that exceed its individual obligations.

D. Combining Two Source Categories.

EPA solicits comment on whether the two existing categories for the affected EGUs should be combined into a single category for purposes of facilitating emission trading among sources in both

[314] 79 Fed. Reg. at 34,908.
[315] 79 Fed. Reg. at 34,892.

categories.[316] EPA also solicits comment on whether combining the categories is, as a legal matter, a prerequisite for (i) identifying as a component of the BSER re-dispatch between sources in the two categories (i.e., re-dispatch between steam EGUs and NGCC units), or (ii) facilitating averaging or trading systems that include sources in both categories, which states may wish to adopt.[317]

NRECA's Response: NRECA opposes the combining of the two existing categories for the affected EGUs into a single category. The NSPS industrial categories have always been defined by engineering design and function. The two respective categories for steam EGUs and NGCC units should remain separate for this reason. NRECA does not believe BSER can legally include trading or dispatch between units, and we do not believe the two categories need to be combined to allow trading or emissions averaging as a compliance option.

E. Enforcement Beyond EGUs.

EPA solicits comment on whether, for state plans where emission limits applicable to affected EGUs alone would not assure full achievement of the required level of emission performance, the state plan must include additional measures that would apply if any of the other portfolio of measures in the plan are not fully implemented, or if they are, but the plan fails to achieve the required level of emission performance. EPA recognizes that a portfolio approach may result in enforceable state plan obligations accruing to a diverse range of affected entities beyond affected EGUs, and that there may be challenges to practically enforcing against some such entities in the event of noncompliance. EPA requests comment on all aspects associated with enforceability of a state plan and how to ensure compliance including enforceability considerations under different state plan approaches, as addressed below in VIII.F.1.[318]

NRECA's Response: As NRECA has made clear throughout these comments, EPA's authority under Section 111 is limited to defining BSER that may be implemented "inside the fence line" at each source – specifically, technological and operational measures that can improve that source's emissions per unit of production. EPA has no authority to require levels of emission reduction that cannot be achieved

[316] 79 Fed. Reg. at 34,855.
[317] 79 Fed. Reg. at 34,892.
[318] 79 Fed. Reg. at 34,909 .

through such source-specific measures. Hence, there is no need to include additional measures in state plans that would apply in the event that the required level of emission performance is achieved.

F. Using Section 110 Approval Mechanisms.

EPA is taking comment on whether, for complete state plans under these guidelines, the agency may use two approval mechanisms provided for in CAA sections 110(k)(3) and (4), 42 U.S.C. 7410(k)(3) and (4). The first mechanism is partial approval/partial disapproval. The second mechanism is a conditional approval.[319]

NRECA's Response: NRECA believes that both partial approval and the conditional approval options for state plans are legally permissible and should be part of the mechanisms for eventual plan approval. NRECA supports the broadest possible mechanisms for allowing full or partial plan approval.

G. Exception From New Source Review Program.

EPA solicits comment on whether, with adequate record support, the state plan could include a provision, based on underlying analysis, stating that an affected source that complies with its applicable standard would be treated as not increasing its emissions, and if so, whether such a provision would mean that, as a matter of law, the source's actions to comply with its standard would not subject the source to NSR. What level of analysis that would be required to support a State's determination that sources will not trigger NSR when complying with the standards of performance included in the State's CAA section 111(d) plan and the type of plan requirements, if any, that would need to be included in the State's plan?[320]

NRECA's Response: As explained earlier in these comments, the 15-year history of EPA NSR enforcement, including the Agency's propensity to prosecute utilities for NSR violations years after the change even though units undergo no actual emissions increase, makes the NSR issues one of EPA's own making. No state provisions could effectively mitigate this concern. EPA must make clear in any final rule that heat-rate improvement projects undertaken to comply with the existing source emission guidelines are exempt from NSR as routine maintenance. Subjecting units to both this rule and NSR may result in

[319] 79 Fed. Reg. at 34,916.
[320] 79 Fed. Reg. at 34,928-29.

economically indefensible decision-making, stranding of assets, and premature unit closures. If unit HRI actions are likely to trigger NSR as determined by the State, the additional cost of compliance including costs of additional emission controls should be included in determining whether a unit can go forward with improvements or be subject to different requirements due to costs.

H. Goal Calculation.

EPA solicits comment on whether any aspects of the goal computation procedure warrant comment. Specifically whether the state-specific historical data to which the building blocks are applied in order to compute the state goals, as well as the state-specific data used to develop the state-specific data inputs for building blocks 3 and 4 are appropriate? (These data are contained in the Goal Computation TSD and the Greenhouse Gas Abatement Measures TSD.)[321]

NRECA's Response. Establishing performance standards should be unrelated to state historic data. EPA must establish BSER and the emission standard by taking into account cost, non-air and environmental impacts, and energy requirements. The statute does not contemplate consideration of historic baselines. Also, as required by the statute and existing regulations, States must be granted flexibility in establishing state goals that include goal adjustment based on state-specific or unforeseen circumstances well as consideration of specific facts applicable to designated facilities including remaining useful life.

I. Alternative Calculations; NGCC Data in Re-dispatch.

EPA solicits comment on whether with respect to building block 2, the alternate procedure in Step 3 (applying building block 2), to maximize the resulting emission reductions, it is appropriate to decrease generation from the State's coal-fired steam group first, and then decrease generation from the State's oil/gas-fired steam group (instead of decreasing generation from the coal-fired steam and oil/gas-fired steam groups proportionately).[322]

[321] 79 Fed. Reg. at 34,896-97.
[322] 79 Fed. Reg. at 34,897.

NRECA's Response: The States should have the discretion to determine which plants would decrease generation as NGCC generation is increased.

J. Multi-State Goals.

EPA solicits comment on whether and if so how it should incorporate greater consideration of multi-state approaches into the goal-setting process, and whether and if so how the potential cost savings associated with multi-state approaches should be considered in assessing the reasonableness of the costs of state-specific goals.[323]

NRECA's Response: EPA lacks the expertise to properly assess cost savings associated with multistate approaches. Even if that expertise existed, it would be inappropriate to penalize States that are willing to and can reduce program costs by utilizing multi-state options or to gauge the reasonableness of the costs of state-specific goals by surmising potential economic benefits associated with theoretical multi-state approaches.

K. Five-Year Alternative.

EPA solicits comment on whether the alternate final goals representing performance that would be achievable by 2025, after a 2020-2024 phase-in period, with interim goals that would apply during the 2020-2024 period on a cumulative or average basis as States progress toward the final goals may underestimate the extent to which the key elements of the four building blocks—achieving heat rate improvements at EGUs, switching generation to NGCC facilities, fostering the penetration of renewable resources or improving year-to-year end-use energy efficiency—can be achieved rapidly while preserving reliability and remaining reasonable in cost, and whether the alternate goals can be applied at a greater level of stringency.

NRECA's Response: As detailed earlier in these comments, NRECA has provided numerous reasons detailing that the interim 2025 compliance option and 2030 compliance building block goals are unachievable. Each building block goal is based on flawed assumptions without which the building block

[323] 79 Fed. Reg. at 34,898-99.

goals are not achievable for numerous States. The five-year alternative building block goals are no more achievable for similar reasons; they certainly cannot be rationally strengthened.

L. Emission Reduction Beyond Proposed Goals.

EPA solicits comment on whether a number of other measures that could also lead to CO_2 emission reductions from EGUs such as electricity transmission and distribution efficiency improvements, retrofitting affected EGUs with partial CCS, the use of biomass-derived fuels at affected EGUs, and use of new NGCC units are appropriate to include in a state plan to achieve CO_2 emission reductions from affected EGUs, and if so, whether EPA should provide specific guidance on inclusion of these measures in a state plan.[324]

Response: NRECA supports the inclusion of any measure that mitigates CO_2 as credit towards goal achievement. We do not believe that other measures should be required as a facet of BSER.

M. Substitution by New NGCC EGU.

EPA solicits comment on how emissions changes under a rate-based plan resulting from substitution of generation by new NGCC for generation by affected EGUs should be calculated toward a required emission performance level for affected EGUs. Should, considering the legal structure of CAA section 111(d), the calculation consider only the emission reductions at affected EGUs, or should the calculation also consider the new emissions added by the new NGCC unit, which is not an affected unit under section 111(d)? Should the emissions from a new NGCC included as an enforceable measure in a mass-based state plan (e.g., in a plan using a portfolio approach) also be considered?[325]

NRECA's Response: The treatment of new NGCC emissions where the new unit displaces existing generation should be left up the individual State. Including new NGCC NSPS emissions in 111(d) plans in States where the statewide goal in less than the NGCC NSPS is counterintuitive under a state emissions rate compliance alternative. On the other hand, in States experiencing high electricity growth rates thereby negating an tonnage cap and forcing an emission rate compliance alternative, including new

[324] 79 Fed. Reg. at 34,923.
[325] 79 Fed. Reg. at 34,924.

NGCC emissions may well be the only method to meet state goal where the goal is greater that the NGCC NSPS. Therefore, individual States should be given the discretion to decide new NGCC emission inclusion into 111(d) plans.

N. Emission levels that exceeding New Fossil-Fuel Fired EGU NSPS.

EPA solicits comment on whether, where new fossil fuel-fired EGUs emissions performance exceeds the NSPS, the emission difference should be credited toward a State's required CAA section 111(d) goal and allowed as a compliance option.[326]

NRECA's Response: NRECA supports, at the States' prerogative, such as credit inclusion in 111(d) compliance demonstration.

O. Additional Agency Guidance.

EPA states that it intends to make additional technical resources available and consider developing guidance for States, and whether it should provide guidance in other areas beyond those discussed above.[327]

NRECA's Response: NRECA would welcome additional guidance in areas EPA deems appropriate. However, any such guidance should be advisory in nature and not mandatory. EPA should also provide to the States guidance on multi-state plan development.

P. Reductions Concurrent with and before the Plan.

EPA solicits comment on whether there is a rational basis for choosing a date that predates the base period from which the EPA used historical data to derive state goals.[328]

NRECA's Response: Standard-of-performance determinations historically have not been based on historic emissions on any particular date, but instead have been based on standards achievable considering the relevant statutory factors. For this proposal EPA has completely departed from this process and has incorporated one that is flatly illegal. States should be able to appropriately credit CO_2 mitigation activities both concurrent with and backdated before the plan towards state goal accomplishment or allow appropriately adjustment of state goals.

[326] 79 Fed. Reg. at 34.924.
[327] 79 Fed. Reg. at 34,924.
[328] 79 Fed. Reg. at 34,924.

Q. RE and Demand-Side EE in a Rate-Based Plan.

Although EPA is proposing that RE and demand-side EE measures be incorporated into a rate-based approach through an adjustment or tradable credit system applied to an EGU's reported CO_2 emission rate, it is seeking comment on different approaches for providing such crediting or administrative adjustment of EGU CO_2 emission rates, which are elaborated further in the State Plan Considerations TSD. MWH crediting or adjustment approach implicitly assumes that the avoided CO_2 emissions come directly from the particular affected EGU (or group of EGUs) to which the credits are applied. An alternative approach is to provide an adjustment based on the estimated CO_2 emissions that are avoided from the power pool or identified region as a result of RE and demand-side EE measures. In addition, because some of the CO_2 emissions avoided through RE and demand-side EE measures may be from non-affected EGUs, how might this be addressed in a state plan, when adjusting or crediting CO_2 emission rates of affected EGUs based on the effects of RE and demand-side EE measures or otherwise, how these dynamics may be addressed?[329]

NRECA's Response: This is an issue that should be decided by individual States, so long as there is a reasonable assurance that there is not a double counting of benefits

R. RE and Demand-Side Evaluation, Monitoring, and Verification.

EPA solicits comment on whether the approaches described in the context of an approvable state plan are suitable, and whether harmonization of state approaches, or supplemental actions and procedures, should be required in an approvable state plan. In particular, EPA intends to establish guidance for acceptable quantification, monitoring, and verification of RE and demand-side EE measures for an approvable EM&V plan, and is seeking comment on critical features of such guidance, including scope, applicability, and minimum criteria. What is the appropriate basis for and technical resources used to establish such guidance, including consideration of existing state and utility protocols, as well as existing international, national, and regional consensus standards or protocols? EPA does not intends to limit the types of RE and demand-side EE measures and programs that can be included in a state plan, provided that

[329] 79 Fed. Reg. at 34,919-20.

supporting EM&V is rigorous, complete, and consistent with the guidance. Should such guidance identify types of RE and demand-side EE measures and programs for which evaluation of results is relatively straightforward and which are appropriate for inclusion in a state plan? Or as an alternative to the EPA's proposed approach of allowing a broad range of RE and demand-side EE measures and programs to be included in state plans, provided that supporting EM&V documentation meets applicable minimum requirements should the guidance should limit consideration to certain well-established programs, such as those characterized in Section V.A.4.2.1 of the State Plan Considerations TSD?[330]

NRECA's Response: Protocols for evaluation, measurement and verification of renewable energy and of end-use energy efficiency for measuring compliance with 111(d) should be left to the States. At a minimum, EPA should accept the methods of evaluation, monitoring and verification that States have adopted as part of their renewable portfolio standards and end-use energy efficiency without any modifications. Those States with existing RE and EE programs engaged in a stakeholders' process during which parties negotiated the terms of their RPS and EE programs. These States should not be asked to re-hatch the process and undo the systems in place. It will be too costly and imprudent to do so.

S. RE and Demand-Side EE Reporting Obligations.

EPA lists examples of potential reporting obligations for affected entities implementing RE and demand-side EE measures in an approvable state plan are provided in the State Plan Considerations TSD. Are there any comments on these examples and suitability of potential approaches described in the TSD and any other appropriate reporting and recordkeeping requirements for affected entities beyond affected EGUs?[331]

NRECA's Response: Protocols for reporting should be left to individual States to determine.

[330] 79 Fed. Reg. at 34,920-21.
[331] 79 Fed. Reg. at 34,922.

T. Emission Reduction Affecting Multiple States.

EPA solicits comment on whether an emission reduction becomes duplicative (and therefore cannot be used for demonstrating performance in a plan) if it is used as part of another State's demonstration of emission performance under its CAA section 111(d) plan.[332]

NRECA's Response: This is an accounting issue for States to resolve to avoid double counting. EPA's involvement should only be as a last resort. Upon resolution, state goals should be modified as appropriate but the credits should not be voided resulting in no state benefit.

U. Compliance Averaging Time.

The proposed Carbon Pollution Standards for new utility fossil fuel sources proposed an averaging time for an emission standard of no longer than 12 months. Similarly, the EPA proposes for the existing source rule that an appropriate averaging time for any rate-based emission standard for affected EGUs and/or other affected entities subject to a state plan is no longer than 12 months within a plan performance period and no longer than three years for a mass-based standard. Should longer and shorter averaging times for emission standards included in a state plan be considered?[333]

NRECA's Response: There is no apparent reason why the compliance averaging time cannot be equal to the performance period. The 12-month averaging time proposal is too short for existing units that may have to compensate for unforeseen circumstances such as increased run time due to inclement weather or unexpected outages of other generating units, etc.

V. Goal Performance Tracking.

In addition to demonstrating that projected plan performance will meet the interim and final state goals, the EPA proposes that state plans must contain requirements for tracking actual plan performance during implementation. Should, in addition to submitting a plan demonstrating emission performance through 2030, States be required to make a second submittal in 2025 showing whether their plan measures would maintain the final-goal level of emission performance over time? If not, should the state submittal

[332] 79 Fed. Reg. at 34,913.
[333] 79 Fed. Reg. at 34,912-13.

would be required to strengthen or add to measures in the state plan to the extent necessary to maintain that level of performance over time? Would 2025, or an earlier or later year, the optimal year for a second plan submittal under the second option?[334]

NRECA's Response: The States should be given the flexibility to determine how to track performance.

W. Multi-year Format for Performance Goals.

The EPA is proposing state-specific CO_2 emission performance goals in a multi-year format to provide States with flexibility for the timing of programs and measures that improve EGU emission performance, while ensuring an overall level of performance consistent with application of the BSER. Specifically, the agency is proposing the state-specific goals (shown in Table 8 on page 34895) which represent emission rates to be achieved by 2030 (final goal) and emission rates to be achieved on average over the 2020–2029 period (the interim goal). EPA invites comment on this and other approaches to specifying performance periods for state plans.[335]

NRECA's Response: The interim goal should be eliminated entirely. They are simply not workable.

X. Compliance Record Retention.

Although EPA is proposing ten years, what is the appropriate time for state plan record retention? The EPA is proposing that state plans must include a record retention requirement of ten years, and we request comment on this proposed timeframe?[336]

NRECA's Response: There is no justification for record retention exceeding ten years.

Y. Offsetting RE and EE with Equivalent Fossil Reductions

Finally, in its October 2014 NODA, EPA requests comment on various proposals for requiring States to eliminate a MWH of fossil fuel generation for each MWH of RE generation added and each MWH of generation avoided through EE.

---

[334] 79 Fed. Reg. at 34,905.
[335] 79 Fed. Reg. at 34,906.
[336] 79 Fed. Reg. at 34,914.

NRECA's Response: If implemented, these proposals would make the current unattainable targets even more stringent. In so doing, it would create insurmountable reliability problems. If States are forced to cut off a MWH of baseload generation for every MWH of intermittent renewable generation, then what will States do when the wind fails to blow or the sun does not shine? Worse than failing to respond to reliability concerns raised by the Proposed Rule, this proposal would exacerbate them.