The National Rural Electric
Cooperative Association

Comments on

Proposed Repeal of Carbon Pollution Emissions Guidelines for Existing Stationary Sources:
Electric Utility Generating Units

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Executive Summary

The National Rural Electric Cooperative Association (NRECA) submits these comments on behalf of America's Electric Cooperatives in support of EPA's proposal to repeal the Clean Power Plan (CPP). While other commenters address the numerous legal flaws and overreaching requirements in the CPP that are otherwise inconsistent with historic implementation of Section 111(d), our comments mainly address the major obstacles and impediments many of the rural electric cooperatives would face if forced to implement the CPP.

The CPP mandates extend far beyond those contained in the dozens of other regulations previously promulgated under Section 111 of the Clean Air Act (CAA). Besides requiring electric utilities to build additional generation or purchase generation from sources outside the CAA's purview, it unabashedly requires significant amounts of the nation's coal-fired electric generation units (EGUs) to either significantly curtail generation or cease generation completely. These requirements are unprecedented and far exceed EPA's authorities.

The nature, consumers served, size and generation portfolios of the electric cooperatives set them apart from others in the electric utility industry. These characteristics also present immense challenges for them if forced to comply with CPP mandates. All but three electric cooperative generators (G&Ts) are small business entities as defined by the federal government, and they are also small generators as compared to their counterparts within the utility sector. Due to federal government mandates between 1978 and 1987 making natural gas uneconomic to utilize for electric generation at the same time very significant needs for cooperative electric generation arose, the vast majority of G&T generation built was coal-fired and remains the predominant source of G&T generation today, accounting for about 60 percent of total G&T

generation in MWh sales as compared to around 30 percent utility-wide. Thus, the CPP-mandated shifts away from coal-fired generation would pose disproportionately significant hardships for the G&Ts as compared to the utility sector as a whole. This is especially the case given that the G&Ts have limited generation portfolios outside coal-fired EGUs making generation options within the G&T systems severely limited in most cases.

Given that the G&Ts would be forced to significantly reduce coal-fired EGU generation or completely abandon some units, the financial burdens for building or buying substitute generation from alternative sources would completely fall on segments of the American population least able to afford it. Collectively, the electric cooperatives serve over 90 percent of the nation's persistent poverty counties within low or sparsely populated geographic areas. Cooperative revenue per mile of distribution line is only 20 percent of the overall utility average. The electric cooperatives have no equity investors to share the financial burdens that the CPP would cause. Thus, cooperatives must rely on debt investors to finance capital projects, and ultimately the electric consumers would bear 100 percent of the debt service costs through increases in electric rates that many rural electric consumers can ill afford.

But the burden on the electric consumer to fund additional generation would not end there. Many of the cooperatively owned coal-fired EGUs the CPP would effectively scuttle still have outstanding debt obligations that must be serviced by rural electric consumers. While the original loans to construct these units may have been paid, many coal-fired EGUs have required additional costly retrofits for emission controls to meet ongoing environmental obligations where the loans to fund these projects remain outstanding. This means in many cases the rural electric consumer would pay twice for the CPP, once for the scuttled coal-fired EGUs that carry outstanding debt and again for the new generation required under the CPP.

Additionally, EPA made numerous and dubious assumptions about the availabilities of efficiency improvements at coal-fired EGUs, natural gas and renewable generation capacities and needed infrastructure to effectuate the required massive shifts away from coal-fired generation to other generation resources to meet CPP goals. EPA assumed coal-fired EGU 4 percent overall efficiency improvement, natural gas generation operating as 75 percent overall capacity, unprecedented growth of renewable generation and significant additional electric and gas transmission infrastructure all would be available simply because they are needed to meet CPP goals. None of these assumptions have any historic precedent or adequate technical justification that otherwise may justify a rational rule. We have included some of the G&Ts' individual case studies to exemplify the CPP's impracticality and associated problematic assumptions.

Lastly, we encourage EPA to propose and finalize a Section 111 regulation to address CO_2 for existing EGUs consistent with the agency's legal authorities and historic traditional source-focused approach. That means the standards can be achievable at the unit without requiring curtailed operation or unit shutdown.

Introduction

I. NRECA and the Electric Cooperative Profile

The National Rural Electric Cooperative Association (NRECA) appreciates the opportunity to comment on EPA's proposed "Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" (also known as the Clean Power Plan), 82 Fed. Reg. 48,035 (October 16, 2017) (Proposed Rule).

NRECA is the national service organization for America's Electric Cooperatives. The nation's member-owned, not-for-profit electric cooperatives constitute a unique sector of the electric utility industry. Due to their size, history, and structure, rural electric cooperatives and their customers would face a distinct and likely catastrophic set of challenges if forced to comply with the Clean Power Plan (CPP). These comments discuss those challenges and explain why they, along with the legal infirmities noted by EPA in the Proposed Rule, justify repeal of the CPP.

NRECA represents the interests of the nation's nearly 900 rural electric utilities. Our members are responsible for keeping the lights on for more than 42 million people across 47 states and over 70% of the United States land mass in the lower 48 states. Electric cooperatives power communities and empower their residents to improve their quality of life. Affordable electricity is the lifeblood of America's economy. For 75 years electric cooperatives have proudly shouldered the responsibility of bringing electricity to rural parts of this country. Because of their critical role in providing affordable, reliable, and universally accessible electric service, electric cooperatives are vital to the economic health of the communities they serve.

America’s electric cooperatives serve all or parts of 88% of the nation’s counties and 13% of the nation’s electric customers, while accounting for approximately 11% of all electricity sold in the United States. NRECA’s member cooperatives include 63 generation and transmission (G&T) cooperatives and 834 distribution cooperatives. The G&Ts are owned by the distribution cooperatives they serve. The G&Ts generate and transmit power to nearly 80% of the distribution cooperatives, which in turn provide power directly to the end-of-the-line consumer-owners. Remaining distribution cooperatives receive power directly from other generation sources within the electric utility sector. NRECA members account for about 5% of national generation. On net, they generate approximately 50% of the electric energy they sell and purchase the remaining 50% from non-NRECA members. All electric cooperatives are incorporated as private entities in the states in which they reside. All but three of NRECA’s member cooperatives are “small business entities” as defined by the Small Business Administration. Distribution and G&T cooperatives share responsibility for serving their members by providing safe, reliable, and affordable electric service.

A. Cooperative Generation Poses Unique Challenges for CPP Compliance

Electric cooperatives strive to offer their member-consumers an array of distributed energy resources including solar, energy efficiency, and energy storage commensurate with the interests of their local consumers and communities. Especially over the past decade, many G&Ts have added significant amounts of renewable electric generating resources, along with natural gas, to their generation portfolios. Nevertheless, due to historical factors, steam-electric, coal-fired generation remains the cooperatives’ principal means of generating electricity.

For the cooperatives, the need for significant coal-fired generation arose out of necessity, not choice. In the mid 1970’s, many existing non-cooperative generation sources could not or would not continue providing affordable and reliable electric generation to the cooperatives. Commensurate with the significant need for cooperative self-generation, the federal government passed the 1978 Powerplant and Industrial Fuel Use Act, 42 U.S.C. § 8301 et seq., which pushed the cooperative generators — the G&Ts — to build significant new baseload generation. That Act *mandated* that all such new generation be "coal capable," so as to preserve natural gas supplies for nonelectric and nonindustrial purposes. The coal capability requirement meant the new generating units bore significantly higher capital costs per megawatt of capacity than units constructed before Congress instituted the requirement. To produce electricity at competitive prices, therefore, the new units had to use coal, which was less expensive than natural gas.[1] The Fuel Use Act was repealed in 1987, but about two-thirds of today's cooperative coal-fired generation was built under the Act's "coal capable" mandate. Given the investments in coal capable generation mandated by the federal government, coal-fired electric generation remains the dominant source of electric generation for G&T cooperatives, comprising 61% of self-generation in 2016, compared to a nationwide average of just over 30%. That is a major reason why the CPP-mandated shift away from coal to other generation sources, if implemented, would disproportionately harm electric cooperatives relative to the other utility sectors.

B. Cooperative and Consumer Characteristics Present Additional Challenges for CPP Compliance

Rural electric cooperatives serve large expanses of the country that are primarily residential and typically sparsely-populated. Those characteristics make it comparatively more expensive and less profitable for rural electric cooperatives to do business than it is for other utility sectors, which usually serve more compact, industrialized, and densely-populated areas.

[1] These units today cannot use natural gas as a primary fuel and provide competitively-priced electricity. Coal to gas converted units typically serve short term purposes or provide non-baseload generation, and are only available where adequate gas supply is available at the site.

This is also why other types of utilities have typically shied away from serving rural areas, thus necessitating the government-assisted advent of the cooperatives. Data from the United States Energy Information Administration (EIA) show that rural electric cooperatives serve an average of 7.8 consumers per mile of transmission line and collect annual revenue of approximately $16,000 per mile of line. In other utility sectors, the averages are 32 customers and $79,000 in annual revenue per mile of line.[2] Due to those geographically-driven differences, 63% of rural electric cooperative members pay higher residential electric rates than do the customers of neighboring electric utilities. Higher rates impede the economic recovery of rural communities and can even challenge their viability. That makes it especially important for electric cooperatives to keep their electric rates affordable and avoid the sorts of unnecessary rate increases the CPP almost certainly would have spawned.

Low population density affects not only the cost of providing electricity, but also the demand for it. In this respect, rural Americans are uniquely vulnerable to rising electricity costs. For instance, in America's rural expanses, people generally do not live in closely-confined houses or in apartments, but in detached, single-unit homes that endure significant exposure to the elements. More than 14% of cooperative consumers live in manufactured housing, which is often energy-inefficient. The national figure, by comparison, is 6%.[3] For those reasons, among others, the average household served by electric cooperatives uses 1,128 kWh of electricity each month, significantly higher than the 825 kWh monthly average for households served by

[2] Information taken from U.S. Department of Energy, Energy Information Administration EIA Form 861.

[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.

investor-owned utilities (IOUs), or the 902 kWh monthly average for households served by municipal-owned utilities (MOUs).[4]

Many cooperative consumers are among those least able to afford higher electric rates. In 2015, the median household income for electric cooperative consumers was 11% below the national average. That is unsurprising, given that electric cooperatives serve 92% of persistent poverty counties (364 out of 395) in the United States.[5] Compounding this problem is the fact that many of these economically disadvantaged customers live in areas with harsh winters and without access to natural gas. Most other heating alternatives, like propane and heating oil, are relatively expensive. Many cooperative customers thus depend on cooperative-generated electricity for warmth during the coldest months of the year. Especially because they lack viable, affordable heating alternatives, it is vitally important to these households that electric rates remain reasonable and that electric supplies remain reliable.

More generally, the electricity supplied by rural cooperatives is vital to rural economies and an essential element of modern residential, rural life. Developing rural parts of the country requires access to affordable and reliable electric power. Factors that increase the cost of producing that electricity, or that threaten its availability, thus pose serious threats to maintenance and growth in large segments of rural America.

To summarize, it is the special province of rural electric cooperatives to serve areas: (1) where it is especially costly to supply electricity; and (2) where aggregate demand for electricity is comparatively low; but (3) where the average resident needs and consumes more electricity

[4] 2016 weighted average data from EIA Form 861; of course, there is wide variation geographically due to different weather patterns and availability of heating alternatives.
[5] Data from the U.S. Treasury's Community Development Financial Institutions Fund (the CDFI Fund), based on U.S. Census data.

than residents elsewhere; and (4) where many of the nation's poorest citizens live. For decades, rural electric cooperatives have met those challenges head-on, with remarkable success. Today, cooperatives continue to play a vital role in life and development in rural communities across the country, despite the obstacles they face in keeping rates reasonable and electricity supply reliable.

C. All Cooperative Financing Costs for Capital Projects Must be Borne Directly by the Cooperative Consumer

Electric cooperatives are not-for-profit entities; they have no investor equity shareholders who can bear the costs of stranded generation assets or investment in new or alternative generation resources. Consequently, electric cooperatives must ultimately pass along capital costs directly to their customers through increased rates. Given that electric cooperatives serve areas with low population density, there are fewer customers to share in those costs. The ones who are there do so, even though they already spend more of their limited incomes on electricity than do comparable MOU or IOU customers. That is yet another reason why cooperatives' members are disproportionately affected by the sorts of rate increases to which the CPP would give rise.

Given that the G&T cooperatives maintain only marginal cash reserves for unforeseen events and anticipated operating expenses, financing for many capital projects necessarily requires reliance on debt investors such as the United States Department of Agriculture's Rural Utilities Service (RUS), National Rural Utilities Cooperative Finance Corporation (CFC), and CoBank. The costs of borrowing, too, are necessarily passed on to cooperatives' members, who invariably pass them on to their consumers. Ultimately, then, it is the cooperatives' members and their consumers who bear the cost of changes required by laws like the Clean Air Act and burdensome regulations like the CPP.

II. The Clean Power Plan Should be Repealed Because Most Rural Electric Cooperatives Could Not Feasibly Comply with It Except by Curtailment or Shuttering of Units, and the CPP is Therefore Arbitrary, Capricious, and Contrary to Law

Section 111 of the Clean Air Act reflects Congress's intent that new and existing sources in a category employ the best technological and operational measures available, after due consideration of those measures' costs and nonair quality health and environmental impacts and energy requirements, to ensure that those sources' emissions are consistent with such measures. It was never intended to require the shuttering or curtailment of any existing source. *See, e.g.*, Standards of Performance for New Residential Wood Heaters, New Residential Hydronic Heaters and Forced-Air Furnaces; Final Rule, 80 Fed. Reg. 13,672, 13,685 (March 16, 2015) (declining to adopt commenter suggestions that EPA ban wood-burning "because section 111(a)(1) of the CAA requires that the emission standards reflect the degree of emission limitation achievable by the application of the BSER [best system of emission reduction].").

Yet the CPP imposes emission reduction obligations that cannot be met, particularly by cooperatives, through any technological or operational measure that reduces the individual source's emissions of CO_2 per unit of electricity produced (a true "standard of performance"). Rather, given that demand for electricity is assumed by the CPP to remain relatively constant, the CPP effectively requires rural electric cooperatives to curtail generation from, or to shutter altogether, their government-mandated coal capable generation in favor of gas-fired or renewable generation.

In this section of NRECA's comments, we discuss the specific threats to cooperatives' viability posed by the CPP and explain why those threats render the CPP arbitrary, capricious, and otherwise contrary to law, thus justifying its repeal.

A. Many Rural Electric Cooperatives Cannot Comply with Building Block 1.

The first CPP building block relies on heat rate improvements to existing coal-fired electric generating units (EGUs). The CPP estimates that, by installing the latest emissions-reducing technologies, coal-fired EGUs can improve their heat rates by up to 4%. That estimate is overly optimistic, both because many owners of generation have already implemented all available heat rate improvements, and because the heat rate improvements EPA assumed could be made to all units simply are not available to many. By way of illustration, when Arizona Electric Power Cooperative (AEPCO) evaluated potential heat rate improvements at three of its EGUs, it found that no such improvements are available at one unit, and that the maximum heat rate improvement achievable at the other two is only 2.1%. After a similar evaluation of its own facilities, East Kentucky Power Cooperative (EKPC) found that it could not achieve *any* further heat rate improvements at its units; all available heat rate improvements had already been made. This should not come as a surprise. Most owners of generation resources are already incented by economic factors to make heat rate improvements to reduce the amount of fuel consumed to generate each megawatt-hour of electricity. The CPP's assumption that all EGUs could make *additional* heat rate improvements simply was never supported by the record EPA amassed.

In addition, when calculating the emissions reductions attainable by a source through heat rate improvements, the CPP wrongly assumed that EGUs can continually replicate, year after year after year, their lowest-ever heat rates simply by using "good maintenance and operating practices." Heat rates are highly variable, not constant. And, as NRECA's members know firsthand, the variability in heat rates is driven largely by factors beyond cooperatives' control. One such factor is the wear and tear to a generating unit that unavoidably occurs with the passage of time. In 2001, for example, Deseret Power Electric Cooperative installed an upgraded rotor at one of its EGUs in northeast Utah, lowering the unit's heat rate. Shortly after the rotor was installed, a routine malfunction at the facility caused some mineral plating to accumulate on the new rotor blades. Deseret did what it could to refurbish the blades, but the heat rate improvements from the new rotor were significantly and irrevocably reduced because of the event. The low heat rate Deseret achieved upon installation of the upgraded rotor thus no longer represents the rate reasonably achievable at the facility, notwithstanding the CPP's assumption about the continuity of heat rate improvements.

Changes in coal quality also play a major role in dictating heat rates at coal-fired EGUs. This factor is particularly important for mine-mouth EGUs. A mine-mouth EGU is one that derives all its fuel from a single mine to which the EGU is adjacent. Not all coal has the same heat value. Some deposits, even ones within the same mine, have naturally higher or lower heat rates than others. Thus, depending on what part of a mine coal comes from, mine-mouth EGUs may have higher or lower heat rates. Furthermore, because mine-mouth EGUs — like the one operated by San Miguel Electric Cooperative in Christine, Texas — tend to be built in remote areas, away from rail delivery systems, they often have no alternative to using coal from the adjacent mine. They cannot "balance out" the variability in their own coal supplies by procuring coal from other mines. The same limit pertains for other EGUs owned by NRECA's members, including Deseret's Bonanza Station in northeast Utah, which must obtain all of its coal from the Deserado mine in western Colorado. For these facilities and others like them, differences in available coal quality make it effectively impossible to realize the CPP's unfounded assumption that EGUs can consistently replicate the lowest heat rates they have ever achieved.

A host of other factors — like cooling conditions and load changes — also affect heat rate variability. Most are beyond existing coal-fired EGUs' powers to control. Sometimes they will permit lower heat rates; sometimes they will necessitate higher ones. But the first CPP building block demands the impossible by effectively requiring EGUs to consistently attain the lowest heat rates they have ever achieved.

That is especially true given that the CPP's two other building blocks require reduction in the overall utilization of coal-fired EGUs. As EPA itself has recognized, reducing coal units' utilization (capacity factor) typically *increases* CO_2 emission rates. For some electric cooperatives' EGUs, low-load operation can increase heat rate by upwards of 10%, more than negating any possible Building Block 1 heat rate improvements. That the CPP does not account for these changes underscores how unrealistic and unattainable its projections and requirements are, and thus that the rule itself is arbitrary, capricious, and contrary to the law, which requires that a Section 111(d) standard be achievable by existing sources.

In its first building block, the CPP also overestimates the heat rate-improving measures that are available for EGUs to implement. Of consequence to NRECA's members, EPA did not consider that electric cooperatives around the country have already spent hundreds of millions of dollars maintaining their coal-fired EGUs in good operating condition and in that process implemented most of the heat rate improvements on which Building Block 1 is premised. Since many of NRECA's members have already implemented the very technologies called for in the CPP, they are not able to realize the "additional" heat rate improvements that the CPP erroneously assumes will come from use of those technologies. To the contrary the CPP's expectation effectively penalizes these cooperatives for proactively making beneficial modifications to their EGUs.

B. Many Rural Electric Cooperatives Cannot Comply with the Demands of Building Block 2.

The second CPP building block — which calls for electric providers to reduce generation from higher-emitting, coal-fired power plants and replace it with generation from lower-emitting natural-gas plants — is predicated on similarly unattainable emissions reductions from NRECA's members. In the first place, many of NRECA's members do not own or have access to the natural gas generation necessary to replace the electric generation lost by the mandated shift away from coal-fired EGUs. San Miguel, for instance, operates only one EGU, which is coal-fired and not connected to a natural gas supply.

Other rural electric cooperatives have access to some electricity from gas-fired EGUs, but not nearly enough of it to make up for the CPP's forced reductions in coal generation. EKPC, for example, serves localities in eastern Kentucky, where the existing gas-fired units were simply not designed to operate at capacity factors anywhere near the 70%-capacity goal established under the CPP. Even if those units could reliably run that much, the region lacks the infrastructure necessary to transmit the power to cooperatives like EKPC.

The experience of AEPCO's Apache Generating Station underscores the limitations in the generation shifting/repowering approach envisioned in Building Block 2. Apache has a natural gas-fired boiler, but CO_2 emission rate exceeds the CPP's mandated target rate of 1305 lbs. CO_2/MWh, so that merely switching to the natural gas unit does not fulfill AEPCO's obligations. Further, as part of a settlement to avoid a possible $192 million regional haze Federal Implementation Plan (FIP) requirement and with an eye towards the anticipated carbon dioxide rule (eventually the CPP), AEPCO agreed to repower one of its two 175 MW coal-fired units to natural gas. But even this reduction is not enough to preserve operations at Apache's second coal-fired unit because the averaged generation rate remains well above the CPP-mandated rate of 1305 pounds of CO_2 per MW hour.

In many cases, therefore, meeting the targets in Building Block 2 requires constructing new natural gas combined cycle (NGCC) assets, along with the necessary infrastructure. EIA estimates that the cost of a new NGCC facility is just under $1,000/kW.[6] Basin Electric Power Cooperative has calculated that it would have to build approximately 1,740 MW of new gas-fired capacity to comply with the CPP, despite having sufficient coal-fired generation to meet its customers' electricity needs. The new capacity is only part of what will be required, given that sufficient existing infrastructure is simply not available to accommodate the massive amount of new generating resources Basin Electric would need to deploy to meet the CPP's requirements. For Basin Electric to deliver the electricity generated from these new assets to its members, significant new transmission infrastructure would need to be built. Given that the location of all the required new generating assets has not been determined, the number of miles of new transmission lines and substations cannot be quantified at this time. Basin surmises, however, from its past generation development experience that the need for new transmission infrastructure will be substantial. Minnkota Power Cooperative and AEPCO have similarly considered the need to construct massive new NGCC facilities to achieve the emission reductions expected under Building Block 2. Again, in each of these cases, the CPP would not be requiring the improvement of the existing generating resources the rule purports to regulate, but instead is effectively requiring their replacement with new, alternatively-fired generation. Section 111(d) was never intended to operate in this manner.

The enormous cost of constructing new, replacement generation is just one of many problems with complying with Building Block 2. Given that the CPP set a compliance deadline

[6] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf.

of 2022,[7] if implemented according to its schedule, affected utilities would have had just four years to bring online the additional gas-fired EGUs that are effectively required by the CPP. Four years is far too little time to completely develop a new EGU, or even to modify existing ones in ways that would make them CPP-compliant. NRECA's members' internal studies of the issue have repeatedly confirmed as much. Typical lead times for siting, design, engineering, federal, state and local regulatory approvals, federal and state environmental permitting, condemnation proceedings, procurement, construction, and commissioning far exceed four years. Transmission and natural gas infrastructure development alone can take a decade to complete. Minnkota Power Cooperative has evaluated the feasibility of adding natural gas capacity and determined that it would take as long as seven years to bring such a resource online. EKPC has similarly concluded, based on its own independent studies, that it would be exceedingly difficult — and perhaps impossible — to bring new resources online within the time required by the CPP.

Regardless of the problems detailed above, NRECA's members would still face a herculean task to meet the emission reduction targets set out in Building Block 2 because it rests on many premises that do not reflect reality for NRECA's members. For instance, Building Block 2 assumes that existing fossil steam generation will shift to existing gas units within each region "up to a maximum [gas] utilization of 75% on a net summer basis." That 75% figure is based on speculative assumptions about the level of generation the existing fleet can achieve, but is unsupported by real-world data. Among other things, it does not assess the fleet's real-world constraints, nor does it account for things like eventual deterioration and retirement of existing units.

[7] The CPP itself has been stayed by the Supreme Court since February 9, 2016. It is not clear how the courts or EPA would treat the CPP's implementation deadlines if the rule were ever implemented. Presumably, those deadlines would, at a minimum, be pushed back by an amount of time equivalent to the duration of the stay. Even that, however, would pose extraordinary challenges for compliance.

The CPP relies on three types of data to support its assumption of a 75% capacity factor. None of that data actually supports the assumption, though. First, EPA cited a statistical analysis based on 2012 generation which revealed the overall average capacity factor of the gas fleet to have been just 46%. More than 20% of the fleet operated at a capacity factor of less than 20%, and only 5% operated at or above 75%. These data — which occurred in a year with historically low natural gas prices that already incentivized the use of gas generation — hardly establish that a fleet-wide capacity factor of 75% is achievable. In fact, the existing fleet would have to increase its generation by about two-thirds from 2012 levels to meet the 75%-capacity factor, and the CPP provides no data or analysis suggesting how that level of generation might be accomplished. In promulgating the CPP, EPA argued that, because capacity factors of 75% or more were achieved in each of the electricity interconnections on at least one day in 2012, this "demonstrate[d] the ability of the natural gas transmission system to support this level of generation." But EPA never explained how these high usage numbers established that such circumstances could be achieved across the fleet day after day, year after year. Nor did EPA consider the various site- or region-specific factors, such as economics, regional grid restrictions, and regulatory constraints that would inform the answer to that question.

Second, EPA attempted to support the 75% figure by presenting data suggesting natural gas generation is expected to grow over time. By itself, that is irrelevant. Such growth will come to a significant extent from the construction of new units. As noted above, the availability of such units in time to satisfy cooperatives' obligations under the CPP is far from certain. Furthermore, since new units cannot be used to average down the CO_2 emission rates for affected fossil-steam units, the data provide no indication that the capacity factor for the existing fleet can increase by the approximately two-thirds the CPP assumes.

Third, EPA pointed to the availability of the existing gas fleet, stating that "EPA assumes that [gas] has an availability of 87%" and that certain units may have availability factors as high as 92%. But "availability" — which is the percentage of hours during a given year a unit is available and not offline due to outages — does not indicate whether those units are capable of operating at sufficiently higher capacity factors over an extended period to meet a fleet-wide capacity factor target of 75%, or are located sufficiently close to coal units to supply the load that the displaced generation would have served. For example, many units with "available" capacity cannot increase utilization due to permit limits on operations, the need to provide dedicated backup capacity for renewable resources, or their location in areas designated as nonattainment for one or more ambient air quality standards.

EPA never addressed those critical questions in promulgating the CPP, thus rendering the rule arbitrary and capricious. Even if fleets could physically achieve such a high capacity factor, Building Block 2 can work only if those fleets are in areas where they can serve demand that would otherwise be supplied by coal generation. For example, it is of little use that a gas unit in Florida can physically operate at a 75% capacity factor if the coal generation it needs to displace is in EKPC's territory in Kentucky, even though both locations are within the eastern interconnection. The electricity transmission grid does not work that way, which is a problem for EKPC because eastern Kentucky presently lacks the infrastructure required to support the expansion of gas-fired electricity called for under Building Block 2.

EPA's Building Block 2 projections are also unreachable because they rely on capacity from gas units' duct burners for redispatch. Many gas units are equipped with duct burners that can temporarily boost power output during peak load periods. But continual operation of these duct burners is unfeasible because they are simply not meant to be used for extended periods of time. Using them that way leads not only to accelerated equipment wear, but also to increased heat rate at the EGU, thus increasing the EGU's CO_2 emission rate and undermining the entire premise of Building Block 2 (as well as Building Block 1).

By all appearances, EPA took little if any of the foregoing into account when developing Building Block 2, thus further demonstrating its arbitrariness and capriciousness. In the end, even if NRECA's members were to go through the extraordinary steps required to procure the gas-fired electricity called for under Building Block 2, and even if they were to do so in time to meet the CPP's compliance deadline, there is no guarantee that they would be able to achieve the unfounded levels of emission reductions Building Block 2 assumes.

C. Many Cooperatives Cannot Comply with the Demands of Building Block 3.

The CPP's Building Block 3, which focuses on substituting increased electricity generation from renewable energy sources for reduced generation from existing coal-fired plants, is fatally flawed because it assumes an amount of new renewables that is unsupported and unrealistic. EPA calculated growth levels of renewable energy anticipated to occur without the CPP that are significantly greater than the ones projected by EIA — the governmental entity charged with forecasting electricity generation and demand. EPA projected that, by 2020, non-hydro renewable energy generation will grow to 406,000 GWh. EIA projects that it will grow only to 335,000 GWh. The 406,000 GWh figure is also substantially greater than the 299,000 GWh of non-hydro renewable power that EPA projected, in the CPP proposal, would be available by 2020. The final CPP does not explain the significant increase in projections, though it appears to flow from EPA's assumption that the maximum historical rate of growth in renewable generation will continue every year indefinitely even though much of that maximum historical growth was fueled by the anticipated expiration of favorable tax treatment for such resources — a factor that, by definition, will not occur year after year. Neither does the CPP explain why EIA's far lower, expert estimation should be discounted, particularly given that EPA is no expert on the issue.

EPA also assumed that, between 2024 and 2030, wind power would continue to grow at the maximum rate it did between 2010 and 2014. Again, there is no explanation for that extraordinary assumption. Based on the law of diminishing returns associated with market and grid saturation, there is strong indication that growth rates, rather than remaining constant, will likely taper off by 2030. In fact, even assuming implementation of the CPP and continuation of wind tax credits through 2023 (which are now set to expire in 2019), EIA's Annual Energy Outlook 2017 forecasts nearly flat growth rates between 2024 and 2030.[8]EPA further assumed that wind power on average can achieve a capacity factor of 41.8%, when historical average capacity factors across the United States from 2008–2014 ranged between 28.1% and 34%. While technologies may be expected to improve over time, any such improvements will likely be offset by the need to place an increasing amount of wind generating capacity in less optimal locations. In any event, EPA failed to adequately explain how average wind capacity factors can be increased by the approximately 30% it assumes.

Thus, based on its unrealistic and unjustified assumptions, EPA fails to demonstrate that renewable resources can replace higher-emitting resources at levels required to meet CPP CO_2 emission reductions requirements. If the CPP does, indeed, overestimate the amount of renewable resources available, the consequences for electric cooperatives and the public could be disastrous if the rule were ever to be implemented. Under the CPP, because no gas or coal-fired EGUs can comply with the applicable performance rates through any technological or

[8] See EIA Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aeo/pdf/0383(2017).pdf, p. 78

operational measures implemented at the EGU, each must meet the CPP's requirements through an "offset," using credits that are *theoretically* available under Building Block 3. But if the credits don't materialize — because, for example, EPA overestimated the availability of renewable power during a given year — then there would be no way for any gas or coal unit to meet the CPP's emission-reduction requirements. That would result in massive asset stranding, which would in turn cause a significant shortfall in energy production. Again, the CPP makes no provision for this, and thus it fails to comply with the statute's explicit requirement that the BSER take into account the "nonair quality health and environmental impact and energy requirement." 42 U.S.C. § 7411(a)(1).

D. Together, the CPP's Three Building Blocks Pose Insurmountable Problems for NRECA's Members and their Customers.

EPA suggests that one answer to the likely avalanche of asset stranding the rule would cause if implemented lies in the voluntary development by the states of an emissions credit trading program or programs, whereby sources could purchase emissions credits from other power suppliers and thereby get more use from their coal-fired facilities. But the trading program on which the CPP relies is unlikely to emerge if the rule is ever implemented, especially in the manner the CPP predicts. The CPP relies on an emissions credit trading program to make the rule work. Indeed, without the emergence of such programs, many electric providers will be unable to comply with the CPP. The CPP itself acknowledges as much. Despite its centrality to the CPP, however, such an emissions trading program is not part of the CPP's definition of the best system of emission reduction. This is because EPA lacks statutory authority under Section 111 to establish such a trading program. Instead, EPA simply assumes that such programs will arise, fully formed, like Venus from a clamshell.

That assumption is unwarranted, as experience over the last two years has shown. Among other things, EPA's assumption depends on several conditions, including that: (1) states will individually adopt trading programs; (2) those states will then coordinate with each other to allow for interstate trading; and (3) participants within the coordinated trading programs will generate and trade enough credits to allow compliance for all sources. Nothing in the CPP establishes that any of this will happen, because, of course, it cannot. The rule merely "anticipates" that "organized markets will develop," as they have in some other, very different contexts. The mere fact that trading programs have arisen before, in other contexts, hardly means that they will arise here, let alone at the level of robustness that is a fundamental assumption of the CPP.

Statements made by California during the early days of the CPP suggest the difficulties inherent in establishing multi-state trading programs without a federal mandate. In its proposed compliance plan for the CPP, California's Air Resources Board explained that, before California can link its emissions trading program with other jurisdictions, the Governor must find that: (1) the linked program complies with California's requirements for greenhouse gas reductions; (2) California will be able to enforce several of its environmental laws against entities subject to regulation under those statutes *and* against entities located in the linking jurisdictions; (3) the proposed linkage provides for enforcement of applicable laws by the linking jurisdiction of program requirements at least as strict as those required under California law; and (4) the proposed linkage will not impose any significant liability on California or its agencies for failure associated with the linkage.[9] Only if another state's program meets each of those requirements may California even consider linking with that program.

[9] https://www.arb.ca.gov/cc/powerplants/meetings/09222016/proposedplan.pdf

NRECA is aware of no formal position taken by any collection of states to ensure the existence of the necessary trading programs, or that they will meet the requirements for linking under various states' laws. Given that the states take substantially different policy positions regarding if and how to regulate emissions, it appears unlikely they will agree on uniform emission-credit-trading programs.

EPA's whole CPP regime collapses entirely if new, multi-state trading programs do not germinate. Without the programs, many electric providers have no realistic chance of meeting their obligations under the CPP, except by stranding or shutting down even more assets. And that is exactly what many of NRECA's members forecast will happen if the CPP ever takes effect. AEPCO, for instance, has determined that, in part because of the high elevation and relative age of its EGUs, it cannot comply with the CPP and continue to operate all of its existing plants. Even if AEPCO shuts down its older gas-fired EGU, the CPP would still likely forbid AEPCO from running its remaining coal-fired EGU at a capacity factor that would be high enough to support long-term use of that unit.

Many of the other units that would be shuttered because of the CPP have decades of remaining useful life that would be cut short by the CPP. The costs associated with such prematurely-shuttered units would ultimately be borne by the cooperatives' members, who as discussed above are among the least able in the country to bear such costs. By way of illustration, Basin Electric, owns and operates multiple coal-based units with useful lives extending beyond 2040. In 2015, when it analyzed what it would need to do to comply with the CPP, Basin determined that, *even if* it developed approximately 1,350 MW of new wind *and* 1,740 MW of new natural gas resources, it would *still* have to shut down operations at four of its existing coal-fired steam generating units, representing approximately 43% of its existing coal-fired generation capacity.

Basin's predicament is hardly unique among cooperatives, which generally have smaller fleets than other electric utilities. Relative to other electric providers, therefore, cooperatives will have an especially tough time meeting the CPP's generation-shifting requirement, simply because they typically have less flexibility within their fleets to generate power from different sources.

Perhaps the most dramatic illustration of this is the scenario facing San Miguel, which owns just one EGU, a coal-fired plant that began operating in 1982. San Miguel is not connected to a natural gas supply, nor does it have access to renewable generation. It has only the one coal-fired plant to supply energy to its member-customer, the South Texas Electric Cooperative. Due to fuel, age, emission controls for other pollutants, and other limitation, San Miguel's GHG emissions are much higher than the CPP's categorical standard. That means the only way for San Miguel to continue operating the plant — its only EGU — is to substantially curtail its use or purchase vast quantities of emissions credits, or to try some combination of those two. Having studied those options, San Miguel has projected that the CPP would require the unit to be retired in 2022 — the day of the CPP's present compliance deadline and a full 15 years before the end of the unit's expected useful life. As soon as that day arrives, the San Miguel plant will no longer be able to be dispatched at anything like its historic capacity factor. Due to forced reductions in capacity factor, the fixed costs of operating the plant would be distributed over fewer megawatts of generated electricity, making the plant more and more uneconomical to operate until it ultimately must close (along with the mine that supplies it).

San Miguel is not the only cooperative that lacks access to the gas or renewable resources on which the CPP relies. EKPC serves a part of the country (eastern Kentucky) where natural resource constraints make solar and wind power uneconomical and not viable. Thus, the CPP's third building block is not accessible to cooperatives like EKPC. What is more, even if EKPC tried to reduce its emissions by shifting heavily into gas-fired electricity, the infrastructure in its region is inadequate to support more than a fraction of what EKPC would need to meet the CPP's requirements. Improving the infrastructure would cost billions of dollars and take much more time than the CPP allows. The upshot is that EKPC would not have any choice but to curtail or shut down their coal-fired EGUs to comply with the CPP. EKPC would then have to rely on the PJM market to supply needed generation, and risk exposure to uncertain and possibly astronomical cost increases for electricity. Alternatively, replacing the EKPC's coal-fired EGU with a gas-fired EGU would take 5 to 7 years to permit and complete construction assuming gas availability. In the end EKPC's consumers would pay twice for electricity, once for the stranded unusable coal-fired EGU and again for purchased power or for the new gas-fired EGU.

Curtailing or shuttering existing EGUs carries enormous consequences — for the cooperatives that own them, for the cooperatives' customers, and for the country. When a cooperative is forced to partially or wholly impair an EGU, that impairment is irreversible. Furthermore, when cooperatives are forced to retire or curtail active EGUs, it invariably makes the cooperatives' rates less competitive with the rates of other electric utilities in their markets, making it more difficult for the cooperatives to sell any surplus electricity they generate. That, in turn, effectively concentrates all the cooperative's operating costs on the cooperatives' member-customers — again, in many instances those who are least able to bear such costs.

Forced curtailment or early retirement of assets imposes substantial costs in other ways, too. By compelling cooperatives to strand baseload coal-fired EGUs, the CPP jeopardizes the cooperatives' abilities to pay for the additional capacity the cooperatives are required to build to comply with the CPP. Relatedly, many cooperatives carry significant debt with respect to some of the assets that will be prematurely retired under the CPP. The cooperatives built and paid for those assets with the understanding that they would operate for several more decades, during which time they would produce electricity that could be sold to pay off the debt accrued to build them.

By stranding those assets, the CPP makes it significantly harder for cooperatives to repay the debts incurred to build the assets.[10] To avoid that difficulty, cooperatives must charge higher rates for electricity from other EGUs in their fleets. In such a scenario, the cooperatives' member-customers pay twice: once for the debt service on the assets that the CPP has forced the cooperatives to strand, and then again for the substitute electric power mandated by the CPP's generation-shifting requirements.

Ultimately, then, it is the cooperatives' customers who pay for the CPP in areas of the country served by rural electric cooperatives. They pay for the stranded assets and other lost capital investments brought about by the CPP's requirement. They pay for all the surplus electricity that was formerly sold to other entities, but would now be uneconomical to generate. Most of all, consumers pay higher rates for the more expensive electricity mandated by the CPP. Shifting energy sources from coal-fired generation to gas-fired and renewable sources will inevitably — and substantially — increase the cost of the electricity that cooperatives generate. NERA estimates that under the CPP, "[d]elivered electricity prices would increase by about 12

[10] The persistence of the debt, in turn, has a negative effect on the cooperatives' credit ratings, which will hurt the cooperatives' ability to borrow funds necessary to pay for the other additions required by the CPP.

percent on average over 2017 and 2031," before even considering the cost of needed transmission and natural gas infrastructure.[11] This hardship will be borne by populations already facing significant economic difficulties.

Take the example of Associated Electric Cooperative. The average income of Associated's residential member-consumers is between $25,000 and $50,000 a year. Sixteen percent of Associated's customers make less than $25,000 a year. These incomes are lower than national averages. If Associated is required to build additional generation or purchase otherwise unnecessary power to comply with the CPP limits on CO_2 emissions, it will directly result in higher electricity rates for Associated's lower-income customers. The increase in costs will be especially pronounced because, like many other rural electric cooperatives, Associated has fewer customers per mile of transmission line. For instance, the second largest investor-owned utility in Missouri has 29.62 customers per mile of transmission and distribution line, whereas Associated's member cooperatives have only 6.4 customers per mile of line, making its customer density 80% less than that of the investor-owned utility. As a result, Associated has far fewer customers to share the costs of its infrastructure and capital investments.

The same holds true for most of NRECA's other members. One-third of the area served by AEPCO, for instance, sits below the federal poverty line. The figure is 20% in the area served by San Miguel. The USDA characterizes 20 of the 87 counties served by EKPC as in "persistent poverty." The increased costs that come with the CPP are not something many rural electric cooperative customers can bear.

As explained earlier in these comments, affordable electricity is more than a mere convenience for cooperatives' consumers; it is a necessity. Many of them depend on electricity

[11] *See* Potential Impacts of the EPA Proposed Clean Power Plan, NERA Economic Consultants, at S-6 (Oct. 2014).

to heat their homes in winter. These consumers lack access to natural gas, and they lack the money to heat their homes with expensive fuels like propane or heating oil. For these consumers, electric heating is often the only option.

Not only do cooperatives supply a disproportionate number of poor and rural families with affordable electricity, but they also supply the jobs that bolster their customers' communities. Thus, by mandating that certain plants curtail or stop operations, the CPP effectively deprives communities of much needed jobs. AEPCO's Apache Generating Station, for instance, directly or indirectly employs over 230 people, and it requires hundreds of additional skilled contractors that work at the plant during maintenance outages and capital project implementation. Between 300 and 550 contractors worked at Apache during maintenance outages from 2013 to 2015. If AEPCO is forced to close that facility or curtail its operations to comply with the CPP, layoffs will be the inevitable result. Cochise County, Arizona, where Apache Generating Station is located, will suffer economically painful consequences due to those layoffs and the corresponding reductions in critical tax revenue. That is to say nothing of the indirect effects — jobs lost due to a cessation of business-to-business transactions between AEPCO and its suppliers — that would result from closing the Apache Generating Station.

For San Miguel, the consequences are even graver because that EGU also supports a working coal mine. Closure of the EGU means closure of the mine as well, since the mine's operations are tied directly and exclusively to the operations of the EGU. In Atascosa County, where San Miguel sits, some of the highest paying jobs are at the plant and the mine. In all, San Miguel is directly responsible for more than 400 jobs in the local community, plus hundreds of contractor positions. It supports a payroll of $35 million annually, to say nothing of the indirect support it provides for numerous other local businesses and their workers. A 2014 study found that, in Atascosa County alone, San Miguel's operations supported an estimated 969 jobs and over $276.6 million in annual economic activity. Those benefits would all disappear if, as is likely if the CPP were implemented, San Miguel were forced to retire its power plant.

None of those costs is necessary for purposes of supplying electricity. To the contrary, some rural electric cooperatives currently have surplus generating resources at their disposal, which they currently sell to other providers to defray costs for the cooperatives' members. Minnkota, for instance, has excess generation projected until 2030. Procurement of gas, wind, solar, or other renewable electricity serves no discernable purpose except to comply with the CPP's arbitrary and unsupported regulatory mandate.

Aside from the harms to cooperatives, their consumers, and their communities, the CPP threatens the reliability of energy supplied in the communities served by rural electric cooperatives. The premature closing of Apache Generating Station's key generating assets, for instance, will jeopardize electric reliability in southern Arizona. In addition to supplying electricity, the units at Apache Generating Station are utilized year-round to provide necessary dynamic voltage support and to prevent transmission system instability in the area. The surrounding transmission system has been designed around Apache Generating Station. Displacing Apache's resources will cause untenable voltage decline of various transmission elements, along with physical inability to import required power resources for its customers at the levels they demand.

Even where the CPP does not require closure of coal-fired EGUs, its requirement that many of them shift to backup generation creates reliability risks. When units designed for baseload generation are changed to serve as backup generation, they wear out more quickly because of the changed use conditions. The result is not only increased production costs, but also diminished reliability across the system.

Problems of that sort could have been discovered during the rulemaking process, except that in promulgating the CPP, EPA never conducted a true reliability assessment of the generation-shifting required under Building Blocks 2 and 3. It merely assumed that others could "develop a pathway" to a reliable electricity system. That sort of baseless assumption is especially dangerous when electrical reliability is at issue. This is one reason why, in its comments on the proposed CPP, NRECA advocated inclusion of a reliability safety valve (or some state-regulated substitute).[12] If no such safety valve is in place, events like natural disasters or unexpected severe weather — which require dynamic and flexible responses — could have truly disastrous consequences.

The CPP's BSER has not been demonstrated and is not achievable by individual sources. The CPP's explanation about how the three Building Blocks will operate in conjunction with one another is entirely speculative. The CPP does not conduct the kind of individualized assessment the Clean Air Act wisely requires in determining whether a proposed BSER is available to a given source. That is why Section 111(d) specifically reserves to the individual states the job of promulgating a performance standard, after EPA specifies the BSER, based on the state's evaluation of the extent to which each individual existing source within its borders can implement that BSER and on what timeline. The uniqueness and complexity of individual power plants makes this source-specific inquiry especially important. Site-specific factors often prevent individual units from achieving performance equal to region-level assumptions for a given technology. The CPP does not make those unit-level evaluations and effectively and unlawfully

[12] A copy of NRECA's written comments on the proposed CPP is attached for EPA's convenience and incorporated by reference.

strips the states of their authority to do so. Instead, the CPP applies broad assumptions about whole source categories, and what sources in those categories *might* achieve, based on region-wide applications of the Building Blocks. There is no guarantee in the CPP that the BSER adopted is even feasible for many affected EGUs, notwithstanding that the Clean Air Act requires such a guarantee before allowing implementation of BSER.

Similarly, in promulgating the CPP, EPA failed to meaningfully assess the massive infrastructure build-out and upgrades that must occur as part of Building Blocks 2 and 3. Replacing fossil fuel generation with new generation requires transmission infrastructure. EPA has never shown that the CPP's anticipated replacement generation can be delivered in a manner that ensures reliable power to meet user demands in all parts of the country. EPA has also failed to demonstrate that existing gas pipeline infrastructure would suffice to meet the substantially increased demand for gas-fired electricity under the CPP.

Instead of assessing how new infrastructure will be created and paid for, the CPP blithely assumed little additional infrastructure will be needed. That assumption runs contrary to the warnings from a chorus of experts. For example, the North American Electric Reliability Corporation (NERC) — the regulatory authority charged with ensuring the reliability of the North American bulk power network — concluded that the CPP's "transformative shift" in electricity generation would "lead[] to the need for transmission and gas infrastructure reinforcements." NERC noted that thousands of miles of new high voltage transmission would be required to satisfy reliability and contingency analysis requirements. Similarly, Regional Transmission Organizations ("RTOs") charged with operating electric systems to balance generation and demand warned that substantial new infrastructure was needed to ensure reliability. Nothing in the CPP guarantees that the necessary infrastructure will be developed in a way that ensures that the CPP can be implemented in an effective and reliable way.

NRECA notes that these flaws, which render the CPP arbitrary, capricious, and otherwise contrary to law, are in addition to those outlined by EPA in its proposal to repeal the CPP and discussed at length by the Utility Air Regulatory Group (UARG) in its comments. NRECA agrees with the statements made by EPA in its proposal to repeal the CPP and with UARG's comments. But NRECA also urges EPA to consider the additional grounds advanced here as further bases for determining that the CPP was ill-advised, fundamentally ungrounded, and contrary to the plain meaning of and longstanding practice under Section 111 of the Clean Air Act.

The CPP should be repealed, and it should be replaced as promptly as possible with a rule that comports with the limits Congress placed on EPA's authority in Section 111(d) and that provides the states with the right to develop standards of performance for existing fossil fuel-fired units after taking into consideration the remaining useful life of units and other factors specifically enumerated in the statute and EPA's longstanding regulations.