The National Rural Electric Cooperative Association

Comments on

Proposed Amendments to the New Source Performance Standards (NSPS) for Greenhouse Gas (GHG) Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units

Submitted Electronically in response to the Small Entity Representative Pre-Panel Outreach

to:

The Environmental Protection Agency

via

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by

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I. Electric Cooperatives: Small Entities and unique characteristics

The National Rural Electric Cooperative Association (NRECA) appreciates the opportunity to comment on the Environmental Protection Agency's (EPA's) Small Entity Representative Pre-Panel Outreach on Proposed Amendments to the New Source Performance Standards (NSPS) for Greenhouse Gases (GHG) Emissions from New, Modified and Reconstructed Stationary Sources: Electric generating units.

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, providing reliable, affordable, and responsible electricity is the shared commitment of NRECA's members. The association represents nearly 900 not-for-profit rural electric utilities that provide electric service to approximately 42 million consumers in 48 states or 13% of the nation's population. The electric cooperatives provide electric service in 83% of the nation's counties that collectively covers 56 percent of the U.S. landmass, as the map at the end these comments depict.

For over 80 years, electric cooperatives have responded to the needs of their communities and adapted to changes in policy in meeting that commitment. We believe policymakers must continue to balance realism with aspiration, recognizing that any energy transition to less carbon emitting electric generation overall will require additional time and technology and must be inclusive of all energy sources to maintain the reliability and affordability that is the cornerstone of American energy security.

All co-ops share an obligation to serve their members by providing reliable and affordable electric service. This obligation is not without challenges. Electric co-ops serve 92 percent of the nation's persistent poverty counties, and the sparsely populated and primarily residential communities powered by electric co-ops are often the most expensive, hardest to serve areas of our country. Electric co-ops proudly shoulder the responsibility of bringing electricity to these communities. Data from the U.S. Energy Information Administration (EIA) show that rural electric cooperatives serve an average of 8 consumers per mile of line and collect annual revenue of approximately $19,000 per mile of line. In other utility sectors, the averages are 32 customers and

$79,000 in annual revenue per mile of line.[1] Due to those geographically driven differences, 63% of rural electric cooperative members pay higher residential electric rates than customers of neighboring electric utilities. Higher rates impede the economic recovery of rural communities and can even challenge their viability. These facts make it especially important for electric cooperatives to keep their electric rates affordable and avoid any unnecessary rate increases brought about by imprudent regulatory policy.

NRECA's member electric cooperatives include sixty-three electric generation and transmission cooperatives (G&Ts) that generate and transmit power and 832 distribution cooperatives that distribute electric power to cooperative electric consumers. The G&Ts are owned by the distribution cooperatives they serve. Some distribution cooperatives receive power directly from other generation sources within the electric utility sector. Overall, the cooperative distributed electric generation fuel mix includes 19% from renewable generation and over 32% from natural gas fired generation, which is now the dominant fuel source for the cooperative distributed electric generation. Importantly, all but three of NRECA's member cooperatives are "small entities" under the Regulatory Flexibility Act, 5 U.S.C. §§ 601-12, as amended by the Small Business Regulatory Enforcement Fairness Act.

II. Electric Cooperatives' specific interests in this rulemaking

The nation's electric grid increasingly will depend on natural gas generation as a reliable "firm power" source of base load and intermediate load generation with the continuing transition to a less carbon intense grid. These "firm power" functions cannot be fulfilled by renewable energy sources such as wind and solar. These facts, combined with the increasing electrifying of other sectors of the economy, are anticipated to require a three-fold expansion of the transmission grid and up to 170% more electricity supply by 2050, according to the National Academies of Sciences.[2] More electricity demand and more renewable energy will place enhanced requirements on the electric grid and increase measures to enhance grid reliability. In this regard efforts to address greenhouse gas (GHG) mitigation must not jeopardize a resilient and reliable electric grid

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[1] Information taken from U.S. Department of Energy, Energy Information Administration EIA Form 861; Platts UDI Directory of Electric Power Producers and Distributors, 2017.

[2] National Academies of Sciences, Engineering, and Medicine. 2021. *Accelerating Decarbonization of the U.S. Energy System.* Washington, DC: The National Academies Press. https://doi.org/10.17226/25932.

that affordably keeps the lights on and is the cornerstone of America energy security and economy.

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. Section 215 of the Federal Power Act (16 U.S.C. Section 824o) is the legal basis for FERC's oversight of NERC. NERC's jurisdiction includes users, owners, and operators of the bulk power system, which serves nearly 400 million people.

NERC's 2022 Long-Term Reliability Assessment[3] mirrors many of our concerns over future electric reliability. The conclusions and recommendations in the executive summary[4] include:

- Manage the pace of older traditional generator retirements until solutions are in place to continue essential reliability services that include avoiding the loss of necessary sources of system inertia
- Consider the impacts of electrification may have on future electric demand
- Expand resource adequacy evaluations beyond reserve margins at peak times to include energy risks for all hours and seasons
- As retiring conventional generation is being replaced with large amounts of wind and solar planning considerations must adapt with more attention to essential reliability services

Electric generation from natural gas combustion turbines is needed now, and more will be needed in the future to serve these vital needs of maintaining grid reliability and affordability. While this section 111 rulemaking cannot resolve growing concerns over future grid reliability, it could

[3] Report can be found at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf

[4] Id. At 6-7

serve as an impediment to alleviate these concerns for example by proposing a system of emission reduction that is too costly or one that cannot be implemented broadly throughout the country or one for which necessary infrastructure to achieve a performance standard is lacking.

III. Comments on specific issues and questions

- CCUS or clean hydrogen are not a best system of emission reduction (BSER) within the context of section 111. Technologies for these strategies lack necessary associated infrastructure, are too costly, and are not available nationwide. CCUS remains woefully undemonstrated for gas combustors and is not at the same technology development as CCUS for coal-fired generation, where, among other shortcomings, the necessary infrastructure is also lacking.
- NSPS should include peaking, baseload, and intermediate subcategories. NRECA anticipates generation needs for new units will likely change as more and more renewable generation is brought online and existing coal-fired generation is retired. Unit required dispatch could go from peaking to intermediate peaking again over its lifetime. Likewise, unit shifting generation needs could require a unit go from baseload to intermediate back to baseload. The subcategories and requirements should accommodate these kinds of anticipated need changes over a unit's lifetime.
- In addition to above-described subcategory flexibility, the rule should allow compliance flexibility including rate-based or mass limits such as tons/year.
- The rule should allow emissions average as an optional compliance tool
- Combined Cycle with heat recovery stream generation (HRSG) unit with triple pressure with reheat has been commercially applied to very large units but for smaller units, higher unit costs and compromised thermal efficiency, as compared to that of larger units, presents challenges. Presently there are no demonstrations on smaller units.
- Supercritical Steam- There is no commercial application of supercritical steam application on a HRSG unit. Simply put, the "driving force" to generate such steam conditions in a HRSG unit is not potentially compelling as the case maybe for a coal-fired boiler. Thus far there is no commercial demonstrations of supercritical steam application on a HRSG unit
- Supercritical CO_2 in lieu of steam as the working fluid "demonstrated at compressor station", as EPA describes, is not adequately demonstrated technology for section 111 nationwide application. In fact, it has not been demonstrated at any commercial scale.

Extremely high temperature metallurgy as required for an expansion turbine is an ongoing materials science challenge, and the required materials are not proven for commercial duty

- Financial benefits such as tax credits should not be used as a factor to demonstrate reasonable cost of a technology necessary for defining a best system for section 111 application. Financial benefits calculation requires numerous assumptions that may not prove to be accurate, such as the anticipated assumed utilization of the unit as opposed to design capacity upon which the financial benefits may be linked, the assumed timing of the financial benefits, and the presumed intent of the Congress to sustain the benefits for the duration included in the original enacting legislation.

IV. NRECA response to the draft White Paper

A. Section 111(b) regulations and the White Paper should facilitate needed new natural gas generation, not impede it.

As the comments above have stressed, electric generation from natural gas combustion turbines is needed now, and more will be needed in the future to serve these vital needs of maintaining grid reliability and affordability. EPA's draft White Paper addressing gas-fired combustion turbine GHG mitigation technologies, when finalized, must not result in a tool that could be used or easily construed to delay, impede, or prevent the development of much needed natural gas combustion turbine generation to support a reliable and affordable electricity from the grid. Our principal concern is that the draft falls woefully short in fulfilling its main intent "to assist states and local air pollution control agencies, tribal authorities and regulated entities in their consideration of technologies and measures that may be implemented to reduce GHG emissions from stationary combustion turbines." Draft White Paper, page 1.

It is noteworthy that EPA views the draft White Paper, presumably when finalized, as merely providing a "context" for Federal Clean Air Act (CAA) permit development under the Prevention of Significant Deterioration (PSD) program Best Available Control Technology (BACT) assessment, and it "may be useful to EPA" in developing CAA Section 111 New Source Performance Standards (NSPS) best system of emission reduction. Id. Under these CAA programs, any proposed GHG mitigating technology or measure as applied to an NSPS category or a BACT assessment would necessarily undergo regulatory scrutiny addressing the many factors the CAA requires before arriving at a prudent technology or measure. Such scrutiny includes accessing the actual commercial viability, adequate technology demonstration, and a reasonable cost of the technology or measure.

The draft White Paper, however, provides no background or explanation of the additional considerations needed for a reasonable and prudent commercial technology application to a source that would assist a state or local permitting agency in evaluating whether it would be appropriate to consider any of the draft White Paper's technologies or methods in any applicability technology or process determination. If, as EPA states, the White Paper's principal use is to inform state and local permit agencies of GHG mitigation technologies for EGU combustion turbine application, it must be significantly revised consistent with these comments.

Additionally, the draft White Paper needs to appropriately describe the stage of development for each of the emerging and possibly available technologies included in the White Paper. Merely citing planned projects, application of the technologies to other types of units or citing units in other industrial sectors, or citing limited application in an electric utility setting, as the draft White Paper does, easily could lead to false conclusions by local regulators that in fact a given technology is commercially available, adequately demonstrated, or otherwise applicable for a given EGU combustion turbine.

B. CCUS or hydrogen blending are not BSER for Section 111 application

While promising technologies both Carbon Capture Utilization and Storage (CCUS) and hydrogen blending for gas combustion turbines requires, among other advances, vast new developments in infrastructure to allow broad geographic applicability needed to demonstrate best systems of emission reduction (BSER). For CCUS both pipelines and sequestration fields would be to be developed in addition to addressing significant water requirements and mitigating enormous cost of control issues. For hydrogen blending, needed infrastructure to transport and store "clean hydrogen" presents insurmountable obstacles for present day BSER application. Indeed, the existing pipeline infrastructure for transporting natural gas for commercial, industrial, electric utility, and home use is structurally and technically inadequate for transporting hydrogen for blending.[5] While the concept of Hydrogen Hubs shows promise for future application, that infrastructure on a geographic basis in not available today and may not be for years.

The draft White paper includes projects undergoing design exercises on NGCC units. It also details the status of these projects. They are all presently Front-End Engineering Design (FEED) studies that are the first prerequisites to a full-scale demonstration test. In addition to these four projects, DOE in late 2021 announced funding for additional design studies, also as a first step to demonstration tests. These additional studies are also not mentioned in the draft White Paper. These projects engage the Calpine Deer Park Energy Center in Texas, the Calpine Delta Energy Center in California, and a unit to be selected by GE Gas Power for which to design a CCUS process. These are design studies, and additional work must be completed prior to successful demonstration of the technology.[6] Hopefully successful technology demonstrations will eventually lead to lead to commercialization of CCUS on NGCC. The draft White Paper should also stress that at a minimum, commercialization, and technical feasibility is achieved only when a process successfully operates over a wide range of varied sites, and ambient conditions, as well as having a supplier who can provide a performance guarantee.

In summary, the draft White Paper should be revised to appropriately describe the state of technology development in all the technologies identified, especially where a given technology is not clearly already commercialized for EGU combustion turbine application. When used according to its portended purpose the White Paper should provide the reader with accurate and reliable information on the various available methods and technologies including the status of commercialized development and associated costs for application to EGU combustion turbines. Accordingly, the White Paper would need to be updated periodically to correctly represent changes including both setbacks and advancements in technologies and methods, as well as updates on costs of application.

[5] See California Public Utilities Commission Final Report, Hydrogen Blending Impacts Study at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF

[6] See 26 U.S.C. § 48A(g); also 42 U.S.C. §§ 13573(e), 13574(d), 15962(i) EPA may not consider demonstration projects that receive assistance from various federal programs "adequately demonstrated" for the purposes of NSPS, PSD and LAER application.

C. The draft White Paper should be rewritten to address the following specific issues and concerns related to source permitting

The comments above express our concerns with the draft's failure to adequately describe in technical terms the status of technology development for each GHG mitigation technology listed. In addition, the white paper should address the following concepts and concerns:

- Each technology should be categorized based on stage of development potentially applicable to the EGU combustion turbines. Due to the potential inherent differences between EGU combustion operation and combustion turbine operation within the other industrial sectors, it cannot be presumed that a technology even reasonable perfected and possibly even commercialized in one sector has achieved that status for EGU application.

- Each technology should describe its potential application that would be consistent with the purpose and need of the EGU combustion turbine. For example, if an EGU combustion turbine application is for intermittent generation to support existing renewable generation, it would make little sense to consider an Energy-Output Integrated Renewables option described in Section5.6.2. of the drift White paper to complement the combustion turbine. In the context of Section 111 NSPS, the best system of emission reduction cannot effectively "redefine the source." The white paper should make clear that in all permitting cases the GHG reduction technology must be consistent with source objective, purpose, and design.

- Each technology should incorporate guidelines for qualifying and quantifying GHG reductions. For example, the draft White Paper correctly points out in the Hydrogen Section in 5.9 that among the different processes producing hydrogen, the selected one largely determines the amount of GHG emissions mitigation associated with the application of that technology to a combustion turbine. In some cases, GHG emissions associated with the way in which hydrogen is produced can negate any GHG reduction benefits directly associated with using that hydrogen at an EGU combustion turbine. Thus, the draft White Paper should provide appropriate guidelines for evaluation of GHG emissions associated with all technologies associated with a potential combustion turbine GHG reduction option.

- The top-down PSD BACT process notwithstanding, each technology or method description should enable readers to delineate the potential technological applicability to units that are new versus existing units that may be undertaking major modifications. Options at existing units may be more limited due to the physical layout, physical location, and design constraints, and these factors must be considered.

- The draft White Paper must recognize that existing infrastructure capabilities including electric transmission availabilities and supply chain limitations may dictate new unit locations, limiting the potential applicability of some of the options discussed in the draft White Paper, such as hydrogen co-firing, carbon sequestration or pipeline transmission to sequestration. The infrastructure needed to support some of the White Paper's options may not be available at existing sites or new source sites where location may be dictated by source purpose, need, and necessary infrastructure (*e.g.*, transmission capacity). Further, even if a given location my support a GHG reduction option, if the materials or services are not available on a timely basis to utilize that option consistent with source purpose and need, that option should be eliminated.

- The draft White Paper should provide some discussion of the costs and economic feasibility of each of the included technologies and methods. This should include a discussion of the costs and feasibility in relation to the application of the technologies reviewed to new versus existing sources. The discussion also should address any non-air quality health and environmental impacts (benefits and detriments) and energy requirements associated with the technologies under consideration.

- The draft White Paper should recognize that the location of a source is dictated by the generation need and existing transmission capabilities. A given source location may present space constraints or geographical factors that effectively negate availability of wind or sun that make co-locating the combustion turbine with renewable generating infeasible, whereby such renewable constraints would not alter the need for base or intermediate load electric generation in the region.