AMERICAN PUBLIC POWER ASSOCIATION
Powering Strong Communities

2451 Crystal Drive
Suite 1000
Arlington, VA 22202-4804
202 467-2900
www.PublicPower.org

May 28, 2024

U.S. Environmental Protection Agency
Docket Center, Docket ID No. EPA-HQ-OAR-2024-0135
Mail Code 28221T
1200 Pennsylvania Ave, NW,
Washington, DC 20460.

Submitted electronically via www.regulations.gov.

RE: COMMENTS OF THE AMERICAN PUBLIC POWER ASSOCIATION IN THE NONREGULATORY DOCKET ON REDUCING GREENHOUSE GAS EMISSIONS FROM NEW AND EXISTING FOSSIL FUEL-FIRED STATIONARY COMBUSTION TURBINES; Docket ID No. EPA-HQ-OAR-2024-0135

I. Introduction

The American Public Power Association (APPA or the Association) appreciates the opportunity to provide comments in the Environmental Protection Agency's (EPA or Agency) nonregulatory docket entitled, "Reducing Greenhouse Gas Emissions From New And Existing Fossil Fuel-Fired Stationary Combustion Turbines" (the GHG CT Docket or the Docket).[1] EPA created the GHG CT Docket to "gather input about ways [EPA] can design a stronger, more durable approach to greenhouse gas regulation of the entire fleet of existing gas combustion turbines in the power sector under Clean Air Act [CAA] Section 111(d)." EPA intends to re-propose emission guidelines for existing electric generating unit (EGU) CTs and propose revisions to the new source performance standards (NSPS) for stationary combustion CTs and address air toxics for this source category under the national emissions standards for hazardous air pollutants (NESHAP). APPA's members operate power generation plants that include natural gas CTs that would be directly affected by any such future regulation. Therefore, the Association and its members have a strong interest in providing comments to inform EPA's future regulatory approach for this category of sources.

APPA is a trade association composed of not-for-profit, community-owned utilities that provide electricity to 2,000 towns and cities nationwide. APPA protects the interests of the more than 49 million people that public power utilities serve and the 93,000 people they employ. Our members strengthen their communities by providing superior service, engaging citizens, and instilling pride in community-owned power. Our

[1] Docket No. EPA-HQ-OAR-2024-0135. See https://www.epa.gov/stationary-sources-air-pollution/nonregulatory-public-docket-reducing-greenhouse-gas-emissions.

Association advocates and advises on electricity policy, technology, trends, training, and operations. APPA has been heavily engaged in commenting on EPA's solicitations for comments on the CT subcategory. APPA filed comments in EPA's 2022 nonregulatory docket to "Solicit Public Input on the Agency's Efforts to Reduce Emissions of Greenhouse Gases from New and Existing Fossil Fuel-Fired Electric Generating Units" (EPA-HQ-OAR-2022-0723).[2] APPA also filed three sets of substantive comments in the proposed Greenhouse Gas CAA section 111 Rule (the Proposed GHG Rule) docket, which applied to the CT subcategory before EPA decided to defer further action on existing CTs to a future rulemaking.[3]

APPA and our members have been and continue to be dedicated to clean air in our communities and the protection of the environment. Our members have made significant investments to reduce emissions and comply with the suite of air regulations that EPA has promulgated over the last ten years. Many members are impacted by the Final Greenhouse Gas CAA section 111 Rules (the Final GHG Rules)[4] which affects existing coal-fired units and new gas-fired generation. Compliance with the Final GHG Rule will require substantial environmental compliance investments, retirements, and replacement generation to be built. Due to the energy transitions and financial investments, existing gas fired CTs will be more crucial to ground grid stability. Existing natural gas-fired simple cycle CTs serve as quick start generation that complements and follows the load of intermittent renewable resources, like wind and solar. Larger combined cycle CTs offer dispatchable baseload megawatts that anchor the grid. Burdening these essential generation assets with lengthy, costly, or unproven controls would be unworkable. For this reason, APPA members have a significant stake. APPA appreciates EPA's recognition and consideration of the impacts any new requirements will have on existing CTs, on public power as small entities and on grid reliability.

APPA offers comments on the options that EPA will be evaluating, reliability impacts, and the structure of a future regulation. Thank you for considering our specific comments on the Existing Stationary Combustion Turbine EGUs Framing Questions for Stakeholder Input (the Framing Questions) discussed *herein*.

II. EPA's New "Holistic" Approach to Regulating Combustion Turbines Must Ensure an Affordable and Reliable Energy System.

A. New Requirements for Existing Natural Gas Units Must Not Compromise Electric Reliability

1. The Role of CTs in Grid Stability Must Be Preserved.

[2] *See* APPA comments at https://downloads.regulations.gov/EPA-HQ-OAR-2022-0723-0016/attachment_1.pdf

[3] *See* APPA comments at https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0566/attachment_1.pdf (Proposed Rule general comment period); https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0895/attachment_2.pdf (SBAR process); https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-8231/attachment_1.pdf (Small entity comment solicitation).

[4] 89 Fed. Reg. at 39,798 (May 9, 2024).

Existing natural gas CTs are essential to maintain reliability during the power sector's ongoing a transition to lower and non-emitting generation resources. Natural gas CTs are dispatchable resources. In other words, they are available when called upon by grid operators. In contrast, renewable resources are intermittent. Existing natural gas CTs offer similar reliability services as coal-fired units, including acting as a capacity resource and providing inertia and voltage support.

Gas generation comprised nearly 40% of the total U.S. electricity generation in 2022 and 43% of generating capacity based on the Energy Information Administration (EIA) data from 2023.[5] The natural gas sector is expected to continue to grow as older coal-fired units retire and EPA's suite of environmental regulations[6] require costly retrofits, such as carbon capture and sequestration/storage (CCS). Power demands are projected to increase, causing the need for more dispatchable resources to be more acute. With coal generation marginalized, gas generation will be the most sizable,[7] dispatchable generation sector. Maintaining gas generation capacity to serve load during sever weather events, such as those recently experienced in Texas (Winter Storm Uri) and in the northeast (Winter Storm Elliott), is central to avoiding power interruptions.

Gas generation outages during recent large-scale power failures illustrate the importance of CTs to maintain a reliable electricity grid. A recent study confirms that natural gas was the largest source of generating capacity that failed in these emergency events as compared to other fuels.[8] The storm events illustrate how dependent the grid is on reliable natural gas assets. Natural gas may be a bridge to a future with primarily non-fossil generation options. But these data confirm that the future is not now, nor is it reasonably foreseeable when technologies will develop to take the place of natural

[5] EIA, "Electricity generation and heating are the primary uses for natural gas in the United States" (April 28, 2023), https://www.eia.gov/energyexplained/natural-gas/use-of-natural-gas.php; Burns & McDonnell, "The future of Gas Generation in an Increasingly Decarbonized World" (Nov. 21, 2022), https://blog.burnsmcd.com/the-future-of-gas-generation-in-an-increasingly-decarbonized-world; Union of Concerned Scientists, "Gas Malfunction: Calling into Question the Reliability of Gas Power Plants" (Jan. 9, 2024) (UCS Report).

[6] New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39798 (May 9, 2024); Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR Surface Impoundments, 89 Fed. Reg. 38950 (May 8, 2024); Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 89 Fed. Reg. 40198 (May 9, 2024); National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 89 Fed. Reg. 38508 (May 7, 2024).

[7] EIA, "Increased U.S. Renewable and Natural gas generation like to reduce summer coal demand" (June 8, 2023), https://www.eia.gov/todayinenergy/detail.php?id=56760

[8] USC Report at 3.

gas.[9] Therefore, a feasible and cost-effective regulatory solution for gas CTs is imperative due to the nation's reliance on this sector.

Indeed, baseload generation sustains the grid. Baseload CTs serves a different role than cycling gas units or units following seasonal or daily patterns (solar or wind) do. Meanwhile, load-following units are equipped to meet day-to-day variable demand.[10] Plainly, generation assets are not one-size-fits-all due to the fluctuating nature of flexible versus inflexible generation. Grid operators recognize the variability in asset type and their role, which is essential considering the large quantities of baseload coal generation coming off-line. Gas CTs are the most flexible asset fuel group. Depending on the size of the unit, CTs step in as baseload, peakers, or even infrequently operated backup generation during high load events. Any regulation imposed on gas CTs as a category should preserve these roles to assure grid stability.

CTs also play a crucial role in integrating renewable energy. They offer significant flexibility, ramping up quickly to provide power when renewables are not available and ramping down, as needed. This agility minimizes emissions related to start-up and shutdown, supporting the integration of variable renewable resources. Any new rule regulating existing natural gas fired CTs should preserve the ability of CTs to serve this key role in the overall reliability of the electric grid and support clean and non-emitting generation resources.

2. Future Regulation of Gas Assets Should Consider Increasing Demands and Regulatory Pressures

The reliability requirements of the power sector are multifaceted. As electrification increases, the demand for reliable service grows. Additionally, the need for resilience in the face of severe weather remains crucial. Simultaneously, the industry aims to advance clean energy deployment to align with incentives provided by Congress. The energy sector faces a delicate balancing act: ensuring reliability, cost-effective, resilience, and environmental progress while adapting to changing resource availability.

Organizations responsible for electric reliability continue to raise concerns about the reliability of the bulk power system. PJM issued a statement shortly after the issuance of EPA's Final GHG Rules, expressing continued reliability concerns.[11] The Southwest Power Pool (SPP) also issued a statement to its members expressing "concerns about future production capacity remain among those in the power-providing

[9] For a discussion of nuclear asset project development, see DOE, Sector Spotlight- Advanced Nuclear (May 17, 2024), https://www.energy.gov/lpo/articles/sector-spotlight-advanced-nuclear. Some dispatchable nuclear assets have come on-line recently, but many projects are at least 10-15 years away from fruition.

[10] NREL, "The Role of Energy Storage with Renewable Electricity Generation" (January 2010), https://www.nrel.gov/docs/fy10osti/47187.pdf

[11] PJM Statement on the Newly Issued EPA Greenhouse Gas and Related Regulations, See https://www.pjm-eis.com/-/media/about-pjm/newsroom/2024-releases/20240508-pjm-statement-on-the-newly-issued-epa-greenhouse-gas-and-related-regulations.ashx.

sector . . ."[12] These concerns would have intensified if EPA had included GHG requirements for the existing gas fleet in its Final GHG Rules. As EPA has done during the proposed rule and the final GHG Rules stage, the Agency should continue its coordination with the Department of Energy and North American Electric Reliability Corporation (NERC) and the Federal Energy Reliability Commission (FERC) to coordinate the electric reliability.

Grid operators continue to forecast future reliability threats. The FERC 2024 Summer Reliability Assessments (Summer Assessment) highlights "anticipated summer heat, natural gas supplies and hydrologic conditions could affect electric reliability."[13] The Summer Assessment found that in Electric Reliability Council of Texas, Inc. (ERCOT) that raising demand is challenging resource adequacy. The region is experiencing both load growth and insufficient energy supply in the summer evening hours.[14] As a result energy "risks are growing, and this is a risk of supply shortages as solar resources ramp down in the evening hours when demand is high, and transmission constrains limit transfers."[15] This summer Midcontinent Independent System Operator (MISO) is projected to have sufficient resources, for normal summer peak demand. However, the MISO region is flagged as an elevated risk of reliability concerns if the region experiences above-normal peak demand if wind and solar resource output is lower than expected. "Wind generator performance during periods of high demand is a key factor in determining whether there is sufficient electricity supply on the system or if external (non-firm) supply assistance is required to maintain reliability."[16]

In summary, gas CTs play an important function in grid reliability. With increased electricity demand in the United States and regulatory pressures, EPA should preserve the functionality of CTs, their operational flexibility and their overall capacity. No regulation should compromise the ability of CTs to operate at full capacity to meet load.

B. Public power utilities are unique as not-for-profit entities of state and local government.

Public power entities are responsible for supplying reliable, affordable, and sustainable power to the communities they serve. Public power utility customers have lower electricity rates and have shorter outages.[17] Due to their structure, public power

[12] SPP, "Statement on the Recent Greenhouse Gas Emissions Rule," (May 20, 2024), https://www.spp.org/documents/71677/spp%20statement%20on%20epa%20final%20ghg%20rule%20202405020.pdf.

[13] Federal Energy Reliability Commission (FERC) 2024 Summer Energy Market and Electric Reliability Assessment at 2. (FERC Summer Assessment). See, https://www.ferc.gov/sites/default/files/2024-05/24_Summer%20Assessment_0523_0940.pdf.

[14] *Id*. at 24.

[15] *Id.* at 25.

[16] North American Electric Reliability Corporation (NERC) 2024 Summer Reliability Assessment at 5. See, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf. (NERC 2024 Summer Reliability Assessment).

[17] American Public Power Association 2024 Statistical Report at 14-15. See https://www.publicpower.org/system/files/documents/2024-Public-Power-Statistical-Report.pdf.

entities are typically more directly affected by regulations that impose significant financial impacts and aggressive compliance schedules. This Section discusses important considerations for public power utilities that EPA should factor into its decision-making.[18]

Limitations when funding large projects.

Public power utilities do not have investors to raise capital as investor-owned utilities (IOUs) do. Instead, they rely on an existing generation asset's operating income to perform projects, such as environmental compliance projects, or to invest in constructing new generation assets. Both are large endeavors for municipalities and public power. If a project exceeds that operating budget for a given year, public power entities often look to bonds, loans, and emergency funds. To finance large projects, municipalities must have revenue-producing assets to use as leverage to secure a loan or bond. Existing generation is crucial as collateral. A municipality may have already leveraged the asset to perform another large environmental project, such as the installation of an air pollution control device or a large coal combustion residuals project. The municipality may need to wait for the maturity of existing loans or bonds before further indebting the entity. Large expenditures must be spaced over time due to this structure.

Many municipalities, especially our smaller members, have limited emergency funds. The revenue to stash into emergency funds or to fund outside-of-budget projects comes from revenue collected from the sale of power from the generation asset. Consequently, public power entities are particularly sensitive to environmental regulations that require the generating asset to be offline for a long period of time. Without revenue coming in, public power utilities must self-fund debt payments and project costs. The municipality financing structure hinges on the availability of the generating unit. Large and expensive environmental projects are difficult to fund, particularly in abbreviated time frames.

The solvency and financial health of a public power entity has a direct correlation to its availability finance future projects.[19] The city of Denton, Texas provides an example. The city incurred $140 million costs above its budget during Winter Storm Uri. Denton's overall financial position faltered and caused the credit rating agency, Fitch Ratings, to assign a Rating Negative Watch to the series 2017 utility system revenue bonds issued by the city. This rating publicly flags the lending risk due to the city's

[18] Public power utilities serve some of the nation's largest cities (including Los Angeles, California, Seattle, Washington, and Austin, Texas) but most serve smaller communities. Approximately 1,300 of the nation's 2,000 or so public power utilities have 10 or fewer employees and serve towns, villages, or counties with fewer than 10,000 people, and all but 144 of the nation's public power utilities would be considered a "small governmental jurisdiction" under the Regulatory Flexibility Act (5 U.S.C. § 601(5).
[19] See Fitch Ratings,: Fitch Maintains Rating Watch Negative on Denton, TX's Utility System Revenue Bonds, May 11, 2021, https://www.fitchratings.com/research/us-public-finance/fitch-maintains-rating-watch-negative-on-denton- tx-utility-system-revenue-bonds-11-05-2021

weaker leverage profile. Lower ratings often cause interest rates to rise for the borrowing entity, making it more difficult to borrow money.[20]

Costs of projects must not force retirements.

When small entities cannot sustain large environmental costs, their only choice is to shutdown or sell the generation if compliance cannot be achieved. Although selling a generation asset many be even more difficult if the plant is no longer economic because of GHG requirements. Existing generation units would be stranded before their end of life. Public power entities would have to continue paying on loans or bonds for retired assets without the income stream the assets would have generated. EPA must consider costs as it forges a regulatory path for CTs.

Owning generation is vital to public power entities. Expensive power purchases are not a possibility. Unpredictable market conditions are becoming frequent as the market becomes more volatile due to regional transmission organizations (RTOs)/independent system operators (ISOs) experiencing generation shortfalls.[21] In addition, extreme weather events have caused recent exorbitant market purchase prices. Small entities must shoulder large transmission upgrade costs for interconnection of intermittent resources. Renewable generation requires more transmission capability to safely handle peak generation highs (e.g., when the sun shines). RTOs charge large interconnection costs to support the necessary transmission upgrades to support renewables.

Costs to public power customers must be considered.

Public power entities are particularly cost sensitive. New and existing generation project costs are *directly* passed onto public power customers without the benefit of rate recovery. These costs would be passed onto end users, which include residential customers. Public power entities are also seeing rising transmission costs. Increased transmission investment in recent years has resulted in substantial increases in transmission rates in some regions, and this trend is expected to continue. This concern is especially relevant to public power customers in disadvantaged communities, who pay a higher percentage of their income to cover power bills. Electric rates are generally formulated to recover the cost of delivering electricity. Therefore, any new environmental rules applicable to electric generators will result in additional costs to public power utilities, which are passed through to electric customers in America's communities.

C. EPA should build considerations for Public Power into its regulatory structure for any future regulation of CTs.

[20] https://www.garlandtx.gov/DocumentCenter/View/1298/Fitch-Electric-Rating-PDF

[21] For example, the PJM Interconnection region market prices during Winter Storm Elliott in December 2022 exceeded $4,000/MWh at one point during the storm when there was no sunlight to power solar resources. Public power entities and their communities cannot absorb this type of cost.

The foregoing sections outline the challenges public power utilities experience with financing, timelines, and rates. APPA solicits EPA's recognition of this unique sector and asks for meaningful evaluation of the following suggestions for future CT rulemaking:

- Coordinating the retirement of existing CTs and investing in new-generation technologies is imperative. Public power utilities cannot be left without generation assets -- stranding debt – without any revenue source or ability to generate electricity for their customers.
- Public power utilities must be able to continue to own and operate electric generation to mitigate market fluctuations. Public power entities must continue to have the opportunity to generate their own electricity. Otherwise, they would have no option but to purchase power – if it is available – regardless of the real-time market price.
- EPA should consider the cumulative costs of environmental regulations on public power The costs of the Biden Administration's suite of environmental regulations are staggering. Any new compliance costs should be viewed in light of the overlapping costs of *all* new environmental requirements on an entity that must finance multiple projects and, potentially, build replacement generation.
- Compliance costs for CTs should be given critical consideration. The public power entity and customers in the community must shoulder these costs.

III. Guiding Principles to Regulate Existing Combustion Turbines.

Any new regulations affecting existing CTs should fall within intentional guardrails to ensure that EPA achieves its goals to protect human health and the environment while, at the same time, allowing regulated entities to continue to provide reliable, affordable and sustainable power. Given the large diversity of unit types and capabilities, APPA observes the undeniable challenges in regulating CTs. The following principles should be considered:

- ***Reliability—***EPA must recognize that it is imperative to maintain overall grid reliability while transitioning to a clean energy future. Reliability is essential to making the transition a success. Negative reliability impacts due to pressures from the ongoing transition could ultimately slowdown that transition, resulting in fewer environmental and economic benefits. New requirements for baseload CTs must not force these units out of the market as there would not be sufficient dispatchable generation to support the electric grid 24/7. EPA must not further aggravate this precarious situation.
- ***Straightforward—***Any future emissions guidelines should offer a simple state plan procedure. Emissions guidelines should not be overly burdensome or time-consuming for states to implement in state plans or for regulated sources to adopt and implement. More complex and lengthy state plan requirements will particularly burden public power utilities with limited environmental staff.

- ***Flexibility—***During the implementation process, states should be allowed to provide substantial flexibility to sources to meet the standard of performance in the emission guidelines. To assist states, EPA should outline various implementation options in the guideline document that states can adopt. Flexible opportunities that EPA must consider include averaging between units at a plant or fleet level, trading among unaffiliated sources and setting a mass-based limit without an annual backstop these flexibilities should be tailored to the existing natural gas-based turbine fleet.
- ***Source Specific—*** Emission guidelines should account for the diversity of existing natural gas generating units. Existing sources vary extensively by age, size, technology, operating duty, economics, geography, and remaining useful life. The differences in sources are vast and deserve individual consideration due to the different capabilities of the CTs and the role they play on the grid.
- ***Achievable at Different Load Levels and Capacity Factors—***Due to market structures and fluctuations in fuel prices, sources often operate at different load levels and capacity factors, which affect their CO_2 emissions. In many cases, third-party system operators determine when and at what level a generating unit will run. Flexible emissions guidelines should not constrain unit operation as needed for dispatch.
- ***Account for Heat Rate Deterioration Over Time—***CT operational efficiency deteriorates over time, causing heat rates to increase. Less favorable heat rates cause CO_2 emissions to increase and to fluctuate over time. Additionally, CO_2 emission rates can be affected by factors such as cycling frequency and ambient conditions. Any rule must recognize the fundamental nature of CTs and account for these realities.
- ***Cost Effective—***EPA should reject any emission guideline technology chosen as the best system of emissions reduction (BSER) if the cost is too great. Systems that require substantial source changes or large pollution control projects should be carefully analyzed. In addition, the costs of expensive infrastructure, such as pipelines, transmission line upgrades, or storage of CO_2 must also be factored into EPA's cost analysis. As previously discussed, small cannot tolerate a costly BSER. BSER must be cost-effective.
- ***Avoid Permitting Complexities—*** EPA should reject any BSER that would trigger New Source Review (NSR) major modifications or New Source Performance Standard (NSPS) source recategorizations. If a unit must traverse substantial permitting changes due to becoming "modified" or "reconstructed" within the meaning of CAA, section 111(b), permitting timelines and certainty would suffer. NSR permitting would, similarly, cause protracted timelines and associated costs.
- ***Compliance Timelines—*** EPA must account for other required environmental permits needed to support energy infrastructure such as compliance with the National Environmental Policy Act to build natural gas or CO_2 pipelines.

IV. Comments on Specific EPA Framing Questions

In order to facilitate EPA's efforts to solicit input on how to regulate emissions from combustion turbines we offer response to EPA's "Key Framing Questions." The below discussion summarizes APPA's observations and conclusions for Framing Questions #1, #2, #4, and #7.

Framing Question #1

1. *What technologies should the EPA consider as part of the Best System of Emission Reduction (BSER) for reducing GHGs from existing combustion turbines? The following is a list of potential technologies that is not meant to be limiting, but, rather, is meant to suggest the expansive nature of the inquiry on which the EPA is seeking feedback. In addition to the control measures proposed in May, which included carbon capture and sequestration (CCS) and hydrogen co-firing, the EPA is interested in feedback and information on the technologies listed below as well as on other technologies that should be considered.*

    a. *Combustion turbines integrated with battery storage*
    b. *Combustion turbines integrated with solar*
    c. *Improving efficiency of simple cycle turbines by upgrading to combined cycle plants.*
    d. *Improving the efficiency of existing turbines, with retrofit options for both simple and combined cycle turbines.*
    e. *Utility scale fuel cells integrated with combustion turbines*

A. Carbon Capture and Sequestration (CCS) for CTs.

BSER cannot be supported because it is premature. CCS is a nascent technology as applied to combined cycle units. No commercial applications of CCS on combined cycle units could be identified. As a result, operating experience is not available; costs are "highly uncertain." A technology supplier offering to install a CCS system is materially different than saying CCS is commercial availability. Meaningful manufacturer guarantees would be indicative of process performance. Commercial guarantees are not available, and the deployment of CCS would take much longer than EPA's estimate of 5 years.[22]

B. Hydrogen Co-firing for CTs.

BSER cannot be supported because it is premature. Hydrogen (H_2) combustion is another promising technology that is not yet ready for widespread industry development as a best system of emission reduction. Several significant hurdles must be overcome before that can be the case, including EGUs being able to combust large

[22] Declaration of Lynn Helms, Exhibit 16, May 13, 2014. State of West Virginia, et al., Petitioners, v. Environmental Protection Agency and Michael S. Regan, in his official capacity, as Administrator of the U.S. Environmental Protection Agency.

amounts of hydrogen for extended periods of time, a ready supply of hydrogen being available, and ability to transport and store the hydrogen.

Hydrogen in blends with natural gas have been tested for short durations, but testing is limited to five commercial combustion turbines.[23] Four applications were short tests; one has been in continuous operation since July 2021 on a 181 megawatt (MW) CT (Linden CoGen) with only a 12 % H_2 blend.[24] Long-term experience is needed. In addition, the availability of the appropriate hydrogen at sufficient quantities is uncertain. Hydrogen is costly. In comments on the Final GHG Rules, Electric Power Research Institute (EPRI) estimates the H_2 production cost $3–5 per kilogram of hydrogen by 2030 before tax credits, additional costs associated with the hydrogen transport, storage, and delivery could add between $0.30/kg-H2 and $3.30/kg-H2, according to U.S. Department of Energy estimates.[25] Increased hydrogen costs could place additional costs pressure on consumers.[26]

C. Battery Storage and CTs.

Experience is too limited to support BSER. Experience with the use of battery storage and CTs is limited. A few applications using simple cycle CTs have attempted this pairing, but experience is lacking.[27,28,29] Although this technology may be possible, more applications would be needed, as all application are of CTs less than 100 megawatts (MWs).[30]
CT with battery storage is only favorable when existing transmission infrastructure is available.

D. Solar and CTs.

This pairing presents limitations in application. National Energy Technology Laboratory (NETL) and EPRI evaluated the feasibility of paring solar panels and CTs to lower CO2 emissions.[31] Solar power can augment the function of a heat recovery steam

[23] Air & Waste Management Association, EM Magazine, “Carbon Capture, Utilization, and Storage (CCUS) and Hydrogen: The Potential to Contribute to Low Greenhouse Gas Power Generation in the United States” by J. Edward Cichanowicz, April 2024 at 14.
[24] *Id*. at 14.
[25] EPRI Comments on the U.S. Environmental Protection Agency’s “New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule”, EPA-HQ-OAR-2023-0072-0500, (EPRI Comments) at 5.
[26] *Id*.
[27] Hybridized Gas Turbine (GT) Plus Battery Energy Storage Systems (BESS): Technology Benefits and Application Barriers, EPRI White Paper, EPRI 3002022317, August 2021. Available at https://www.epri.com/research/programs/113170/results/3002022317.
[28] Hybrid Plant Provides Clean Power Solution, Power Magazine, October 2, 2023.
[29] Hybrid Generation and Energy Storage Facility, Power Engineers, Available at: https://www.powereng.com/library/hybrid-generation-and-energy-storage-facility.

[30] *Id.*
[31] Turchi, C. et. al., Solar-Augmented Potential of U.S. Fossil Power Plants, NREL Technical Report NREL/TP-5500-50597, February 2011.

generator (HRSG) of a combined cycle, by displacing heat generated by fossil sources with solar; it can modestly low CO_2 per MWh. Ideal applications are for units with duct-firing and thus "reserve" capacity for the HRSG and steam turbine.

Drawbacks are that benefits may be limited or non-existent. If a CT does not have any unused capacity in the HRSG and steam capacity, then solar augmentation is not a benefit. Without such excess capacity, the thermal efficiency of generation could decrease with solar augmentation. In addition, this option may not be practical since 50-100 acres of land may be needed.

E. Fuel Cells and CTs.

BSER cannot be supported due to limited information. The largest project is not yet operating but will be using an 8 MW equivalent hydrogen fuel cell as a utility-scale battery and not in conjunction with a CT.[32] Other fuel cell battery projects are under development, such as Xcel Energy's 10 MW fuel cell capable of 1,000 megawatt hours (MWh).[33] This project is slated to be operational in 2025. BSER cannot be supported for any fuel cell technology in any mode.

F. CT Hardware Modifications.

1. Simple to Combined Cycle CTs.

Conversions can improve thermal efficiency but are expensive. Physical modifications to convert a simple cycle CTs to a combined cycle CT are possible; however, few applications exist. Ramp rate may be limited with such a conversion as units with high ramp rates are desired to manage renewable penetration and may limit the unit's participation in the whole sale energy markets.

A conversion may improve thermal efficiency by 50% or more and is dependent on unit load, whether the HRSG employs duct burners and the means of heat rejection. These types of conversion project require a significant capital commitment and the conversion may not be cost-effective given the remining useful life of the unit. It also requires permitting. Dispatch may be affected by the large project costs.

The two technologies simple cycle and combined cycle CT serve two different needs in the marketplace today, a combined cycle CT may be more efficient and have lower GHG emissions per fuel burned but the market would still need a resource to replace the simple cycle CT to serve peak load.

2. Thermal Efficiency Improvements.

[32] https://www.chemengonline.com/plug-power-and-energy-vault-to-deploy-the-largest-hydrogen-powered-fuel-cell-in-the-u-s/?printmode=1
[33] https://formenergy.com/xcel-energy-receives-approval-to-build-multi-day-battery-storage-at-sherco-site/

Efficiency projects only result in small improvements that will not materially impact CO_2 emissions. Physical modifications are possible to make "hot gas path" improvements to the design and material of construction key components (buckets. nozzles, and combustor). The Southern California Edison Mountainview Generating Station efficiency project demonstrated marginal thermal efficiency improvements.[34] Improvements range based on CT type – improving to about 1% higher thermal efficiency due to these improvements or a 4% increase in generating output.[35]

Framing Question #2

Should the EPA include market mechanisms like mass-based trading or emissions averaging in its proposal?

a. *Should market-based mechanisms be limited to implementation and compliance, or do they have a role in establishing the emissions guidelines?*
b. *Many stakeholders have advocated for mass-based trading. Are there mechanisms (either mass- or rate-based) that can be designed in such a way as to maintain protectiveness while addressing local impacts and the significant uncertainties about future utilization levels for turbines?*

The development of a CO_2 mass-based emissions trading program is an effective compliance tool for states. We believe that any trading regime must be dynamic and cannot be static (e.g., based upon a single historical year)." Rather, the trading program must be permitted to capture future operations, changing dispatch conditions and unit performance. In other words, future operations may not match baseline conditions.

Framing Question #4

What other compliance flexibilities should EPA provide for state implementation guidelines?

Compliance flexibilities are indispensable and should be built into emissions guidelines. APPA supports future emissions guidelines that offer flexible compliance. CTs, as a category, would particularly benefit due to the diversity of unit types. Several concepts that EPA should evaluate are:

- **Multiple-Year Baseline Lookback Period**—Any standard of performance based on a unit's historical baseline emissions performance should evaluate multiple years. Due to the lower cost of natural gas in recent years, CT capacity factors have fluctuated. Pricing and utilization of CTs will be dynamic in future years with the transitioning grid, especially as retiring coal comes offline. The Association believes a unit-specific baseline should be no less than five years,

[34] Mountainview Generating Station – Hot Gas Path Component Replacement, California Energy Commission, Docket Number 00-AFC-02c. November 11, 2016.
[35] *Id.*

but a period of ten years would be preferable. In addition, states should be offered the flexibility to diverge from the chosen emission guideline baseline for the standard of performance with an adequate source-specific justification. Shorter periods of time may not capture the different operating conditions and operating loads of the unit. Moreover, the emissions data smooths out over longer periods of time, removing spikes and other abnormalities seen in shorter review periods.

- **Multiple-Year Compliance Period**—For similar reasons, a compliance period longer than one year minimizes the risk of non-compliance due to changes in load level, capacity factor, and other operational variabilities. This approach would also minimize economic impacts and improve reliability. APPA suggests a multi-year compliance period of at least three to five years for the standard of performance.
- **Sub-categorization offers the existing sources needed flexibility**—Emissions guidelines should support subcategorization. These subcategories will allow EPA to devise durable and tailored emissions guidelines that CTs can achieve as performance evolves over time. They are a heterogenous collection of emissions units. New CTs are more efficient, but older CTs have an important role in grid stability and renewable support. Emissions guidelines should recognize the differences in capabilities, age, and usage, among other things. Subcategories should allow for movement from subcategory to subcategory to allow for fluidity, as the grid changes.
- **Reliability mechanisms**—APPA encourages EPA to consider reliability tools and off-ramps. The Association is encouraged by EPA's decisions to include several reliability mechanism in the recent final CAA section 111 power sector rulemaking. Reliability mechanism that addresses both short- and long-term concerns should be included in any existing CT emissions guidelines to prevent the loss of crucial generation assets. These mechanisms should be addressed in the guidelines themselves, although remaining useful life and other factors (RULOF) may address site-specific nuances.
- **Sufficient time for compliance**—APPA supports timelines that allow public power entities sufficient time to obtain compliance funding and construction. Timelines should also consider the potential overlaps of timelines for other rules, such as the Final GHG Rules. These timelines affect community expenditures -- which must be triaged; unit outage timing – to avoid unnecessary downtime, and, finally, practical project considerations – to account for supply chain, construction resources, and compliance with other environmental requirements (e.g., National Environmental Policy Act (NEPA) for projects using federal funds or on federal lands and environmental permitting).
- **State plan development**—States must have adequate time to prepare state plans. We recommend that states develop their plans and submit them to EPA for approval at least 36 months at a minimum after issuance of any final rule. This timeframe is warranted to allow states to fulfill new meaningful engagement requirements, evaluate remaining useful life and other factors, and assess the reliability impacts of the state plan and their administrative processes.

APPA appreciates EPA's thoughts around these considerations in rule development.

Framing Question #7

> *For EPA's development of the NSPS (40 CFR 60 KKKK) for stationary combustion turbines and to review and update the NESHAP (40 CRF 63 YYYY) for stationary combustion turbines, what are the interactions between these three rulemakings that the EPA should consider?*

While the technologies EPA has identified may reduce CO_2, other emissions may result. EPA should consider these impacts cumulatively as part of its evaluation on how to regulate stationary combustion turbines. The chart below outlines some of the potential non-CO_2 impacts by control technology.

Potential CT Technology	**Potential Non-CO_2 Air Impacts to Consider**
CCS	NOx may slight decrease, however this is dependent on NO_2 in the gas stream; Formaldehyde (increase, removal options may be available); PM may increase if amine carryover into clean flue gas) Increased parasitic load
Hydrogen co-firing	NOx increases or (unchanged if SCR is installed, SCR install causes increase in auxiliary load and possible increase in ammonia); CO is like to decrease, depending on operating time at the revised minimum load; hazardous air pollutants, (HAPs) are likely to decrease because of the reduction on carbon content of the fuel and higher flame temperatures.
Simple to Combined Cycle	A unit with an SCR and CO oxidation catalysis will have lower NOx, CO and formaldehyde but start time and ramp time could be affected including time in non-steady-state modes. Ammonia is a precursor to PM emissions and may require the installation of a baghouse is unit is in a non-attainment area for PM.
CT/Battery Pairing	By potentially reducing startup events, the battery may lower emissions of NOx, CO, formaldehyde, and carbon-generated PM
CT/Solar Pairing	If the CT has unused capacity in the HRSG and steam turbine then lower NOx and CO emission may occur; No impacts on formaldehyde
Hot Gas Path Upgrade	Possible ammonia emissions due to SCR usage; possible decrease of CO; HAPs (undetermined). No material impacts on emissions

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Thank you for considering these comments. The Association looks forward to working with the Agency as it develops this rulemaking. Should you have any questions regarding these comments, please contact Ms. Carolyn Slaughter (202-467-2900) or cslaughter@publicpower.org.