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August 11, 2025

Honorable Lee Zeldin
Administrator
U.S. Environmental Protection Agency
EPA Docket Center
Docket ID No. EPA-HQ-OAR-2025-0124
Mail Code 28221T
1200 Pennsylvania Ave. N.W.
Washington, D.C. 20460

Submitted electronically via http://www/regulations.gov.

RE: Comments of the American Public Power Association on the Proposed Repeal of Greenhouse Gas Emission Standards for Fossil Fuel-Fired Electric Generating Units (90 Fed. Reg. at 25,752, June 17, 2025; Docket Id. No. EPA-HQ-OAR-2025-0124)

Administrator Zeldin:

The American Public Power Association (APPA or Association) is pleased to provide comments to the Environmental Protection Agency (EPA or Agency) on its proposed rule: "Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units" (Proposed Rule).[1]

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 55 million people that public power utilities serve, and the 100,000 people they employ. APPA advocates and advises on electricity policy, technology, trends, training, and operations. The Association and its members have a strong interest in Clean Air Act (CAA) regulations, including those that regulate greenhouse gas (GHG) emissions. Our members own and operate fossil fuel-fired electric generating units (EGUs) that are the subject of regulations the Proposed Rule would repeal. For these reasons, APPA and its members have a significant stake in the Proposed Rule.

APPA supports the Proposed Rule, and we encourage EPA to move forward with finalizing the Proposed Rule. As further explained in these enclosed comments, APPA strongly encourages EPA to first finalize the Alternative Proposal. Doing so—along with the recommended adjustments to the new source performance standards for new stationary combustion turbines, in these comments—would offer APPA members much-needed relief from the 2024 GHG Standards. APPA believes the Alternative Proposal, grounded in longstanding

[1] 90 Fed. Reg. 25,752 (June 17, 2025).

interpretations of the CAA and decades of case law, offers a more certain and durable path to the regulatory clarity the power industry urgently needs.

APPA looks forward to working with the Agency on this rulemaking. Should you have any questions regarding these comments, please contact Ms. Carolyn Slaughter (202-467-2900 or cslaughter@publicpower.org).

Sincerely,

Carolyn Slaughter

Carolyn Slaughter

Senior Director, Environmental Policy

American Public Power Association

Cc: Aarron Szabo, Assistant Administrator, Office of Air and Radiation
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COMMENTS OF THE AMERICAN PUBLIC POWER ASSOCIATION ON THE
U.S. ENVIRONMENTAL PROTECTION AGENCY'S PROPOSED RULE:
"REPEAL OF GREENHOUSE GAS EMISSIONS STANDARDS FOR
FOSSIL FUEL-FIRED ELECTRIC GENERATING UNITS"

90 Fed. Reg. 25,752 (June 17, 2025)

Docket ID No. EPA-HQ-OAR-2025-0124

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I. Introduction and Background

The American Public Power Association (APPA or Association) is pleased to provide comments to the Environmental Protection Agency (EPA or Agency) on its proposed rule: "Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units" (Proposed Rule).[1]

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 55 million people that public power utilities serve, and the 100,000 people they employ. APPA advocates and advises on electricity policy, technology, trends, training, and operations. The Association and its members have a strong interest in Clean Air Act (CAA) regulations, including those that regulate greenhouse gas (GHG) emissions. Our members own and operate fossil fuel-fired electric generating units (EGUs) that are the subject of regulations the Proposed Rule would repeal. For these reasons, APPA and its members have a significant stake in the Proposed Rule.

Public power utilities have taken significant action to address GHG emissions, reducing their carbon dioxide (CO_2) emissions by 33.4 percent from 2005 to 2023, which contributed to the electric generating industry being the industrial sector with the largest amount of GHG emission reductions in that period.[2] Many APPA members have established goals to reduce their GHG emissions, including net-zero goals. Equally important, APPA members have a duty to provide their communities with reliable and affordable electricity. APPA has been concerned that compliance with the GHG standards that the Proposed Rule would repeal would jeopardize this obligation by making the electric grid less reliable and increasing electricity prices.[3] Because of this concern, APPA has taken a proactive approach with respect to the Proposed Rule, including by meeting with the White House Office of Management and Budget (OMB). As APPA explained during that meeting and as further described in these comments, APPA supports

[1] 90 Fed. Reg. 25,752 (June 17, 2025).

[2] Center for Climate and Energy Solutions, U.S. Emissions, https://www.c2es.org/content/u-s-emissions/ (citing EPA and U.S. Energy Information Administration (EIA) data for 2022).

[3] APPA submitted comments on the proposed 2024 GHG Standards. Comments of the American Public Power Association on the U.S. Environmental Protection Agency's 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; Proposed Rule, Docket ID No. EPA-HQ-OAR-2023-0072-0566 (Aug. 8, 2023) (APPA Comments on Proposed GHG Standards). APPA also submitted comments on EPA's supplemental notice of proposed rulemaking to examine electric reliability issues associated with the proposed 2024 GHG Standards. Comments of the American Public Power Association on Supplemental Notice of Proposed Rulemaking for the New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule; Proposed Rule, Docket ID No. EPA-HQ-OAR-2023-0072-8231 (Dec. 20, 2023) (APPA Comments on Supplemental Rulemaking for Proposed GHG Standards). The APPA Comments on Proposed GHG Standards and the APPA Comments on Supplemental Rulemaking for Proposed GHG Standards are incorporated herein and are included in Addendum 1, which APPA is filing with these comments.

EPA's Proposed Rule, and APPA encourages EPA to move forward with finalizing the Proposed Rule.

In 2024, EPA issued revised new source performance standards (NSPS) for GHG emissions from new, modified, and reconstructed fossil fuel-fired EGUs and emission guidelines to address GHG emissions from existing fossil fuel-fired steam generating units (the 2024 GHG Standards).[4] The NSPS, which are codified at Subpart TTTTa of 40 C.F.R. Part 60, were promulgated pursuant to section 111(b) of the CAA, and the emission guidelines, which are codified at Subpart UUUUb of 40 C.F.R. Part 60, were issued pursuant to section 111(d) of the CAA.[5]

The Proposed Rule offers two approaches to repealing or revising the 2024 GHG Standards. The first approach is EPA's "Primary Proposal." The Primary Proposal would repeal the 2024 GHG Standards in their entirety based on a finding that GHG emissions from the covered EGU source category do not significantly contribute to endangerment of public health and welfare.[6] If finalized, the Primary Proposal would also have the effect of repealing EPA's 2015 NSPS for GHG emissions from fossil fuel-fired EGUs, which is codified at Subpart TTTT of 40 C.F.R. Part 60.[7] The second option is EPA's "Alternative Proposal." The Alternative Proposal would revise Subpart TTTTa and repeal Subpart UUUUb based on changes to EPA's best system of emission reduction (BSER) determinations.[8]

As discussed further in these comments, APPA urges EPA to finalize the Alternative Proposal first because doing so (along with adjustments to the NSPS for new combustion turbines as discussed in Section V below) would provide APPA members with the relief that they need from the 2024 GHG Standards. APPA believes that because the Alternative Proposal rests on existing interpretations of the CAA and decades of case law, it provides the more certain and durable route to the relief so urgently needed by the power industry.

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

[5] Numerous parties challenged the 2024 GHG Standards in the U.S. Court of Appeals for the District of Columbia Circuit. *West Virginia v. EPA*, No. 24-1120 (and consolidated cases) (D.C. Cir.). APPA participated in the litigation as a member of the Electric Generators for a Sensible Transition, which is an *ad hoc* coalition of electric generating companies and APPA that joined together for the purpose of challenging the 2024 GHG Standards. The petitioners' briefs in that litigation provide arguments for why the 2024 GHG Standards are unlawful and should be repealed or revised. Those briefs included with these comments in Addendum 2 and incorporated by reference. Opening Brief of Petitioners, *West Virginia v. EPA*, No. 24-1120 (and consolidated cases), ECF No. 2073644 (D.C. Cir. Sept. 6, 2024); Reply Brief of Petitioners, *West Virginia v. EPA*, No. 24-1120 (and consolidated cases), ECF No. 2082029 (D.C. Cir. Oct. 25, 2025).

[6] *See* 90 Fed. Reg. at 25,762-68.

[7] 80 Fed. Reg. 64,510 (Oct. 23, 2015).

[8] See 90 Fed. Reg. at 25,768-77.

II. Executive Summary

APPA's comments on the Proposed Rule are summarized below.

- Demand for electricity is increasing rapidly, and this is forecast to continue for the foreseeable future. Public power utilities need immediate relief from the 2024 GHG Standards to ensure that they will be able to continue providing reliable and affordable electricity to their customers.

    - APPA and others, including regional transmission organizations (RTOs) that are responsible for grid reliability, told EPA during the rulemaking for the proposed 2024 GHG Standards that the standards would threaten electric reliability, would increase health and safety concerns, result in increased electricity costs, and potentially undermine public support for prudent GHG reducing programs. EPA finalized the 2024 GHG Standards despite these serious concerns.

    - The North American Electric Reliability Corporation (NERC)'s recent Long-Term Reliability Assessment predicts massive increases in electricity demand over the next ten years and contains warnings regarding "critical reliability challenges."

    - The 2024 GHG Standards will compound these reliability issues because they will lead to the early retirement of coal-fired generation and because they impose capacity factor limitations on new, larger combined cycle combustion turbines. The 2024 GHG Standards are already having an adverse effect on the ability of electric generators to construct new base load generation to meet increased demand.

- APPA urges EPA to finalize the Alternative Proposal, which if coupled with the revisions needed to the NSPS for new base load combustion turbines in Phase 1 and for intermediate combustion turbines discussed in Section V of these comments, would remedy the legal defects of the 2024 GHG Standards and provide needed relief to the power industry.

- The portions of the 2024 GHG Standards that rely on a BSER of 90 percent carbon capture and storage (CCS)[9] do not comply with the requirements of the section 111 of the CAA, and EPA properly proposes to repeal them.

    - EPA properly proposes to find that CCS is not adequately demonstrated at stationary combustion turbines. The two projects EPA cited in the 2024 GHG Standards to support its determination that CCS was adequately demonstrated actually support the opposite conclusion. The Bellingham Energy Center was a slipstream facility that is not comparable to EGUs, and the Peterhead Power Station in Scotland is not yet operational. Other projects cited by EPA are not operational (or not even constructed).

    - EPA properly proposes to find that CCS is not adequately demonstrated for steam generating units. EPA's determination that it was relied primarily on the Boundary Dam Unit 3 project, which has never demonstrated 90 percent capture of carbon

[9] CCS is sometimes also referred to as carbon capture, utilization, and storage (CCUS).

dioxide (CO_2) and which is a relatively small power plant of only 110 megawatts (MW). Other projects cited by EPA are small, capture CO2 from a slipstream, do not capture CO_2 at a 90 percent level, and/or received federal funding that disqualifies it from consideration as a BSER. EPA also cited unconstructed projects and vendor statements, neither of which can support a BSER determination.

- EPA properly proposes to find that the NSPS and presumptive standards of performance that are based on a 90 percent CCS BSER are not achievable. No commercial EGU has ever achieved 90 percent CCS on a sustained basis, as the 2024 GHG Standards require, and EPA did not cite a single example of a facility meeting this standard in the final 2024 GHG Standards. Other reasons also support EPA's determination that CCS is not achievable, including:

  - The infrastructure needed for CCS, including pipelines and storage facilities, does not exist, and it cannot be constructed by the compliance deadlines in the 2024 GHG Standards.

  - Many areas of the country do not have convenient access to geologic storage for CCS.

- EPA properly proposes to find that CCS is not cost-effective. In past rulemakings, the Agency has consistently rejected CCS as too costly. To get around that problem in the 2024 GHG Standards, EPA inappropriately relied on tax credits. But tax credits do not reduce the costs of CCS; they transfer them from power plant owners to taxpayers. Even if tax credits could be taken into account, there are significant limitations on the ability of an owner to obtain them, and nothing would prevent Congress from taking them away.

- Many other obstacles exist that prevent CCS from being considered as a "best" system to reduce GHG emissions from EGUs, including: (1) geographic and site limitations; (2) water constraints; and (3) parasitic load.

- The portion of the 2024 GHG Standards that identifies co-firing with 40 percent natural gas as the BSER for existing medium-term coal-fired steam generating units does not comply with section 111 of the CAA, and EPA properly proposes to repeal it.

  - Requiring a coal-fired EGU to become a "hybrid" plant that burns 40 percent natural gas constitutes impermissible generation shifting and is beyond EPA's authority.

  - Even if fuel switching were permissible, which it is not, the presumptive emission limit based on 40 percent co-firing is not achievable because the majority of coal plants do not have access to natural gas, and the vast majority of those plants that do have access to gas use it only at very low levels for boiler startup or to hold the unit in "warm standby."

  - Co-firing with 40 percent natural gas is not cost-effective because of the need to construct expensive pipeline infrastructure.

- EPA properly proposes to repeal the requirements for existing natural gas- and oil-fired steam generating units because these requirements would result in only de minimis—if any—emission reductions but would impose significant requirements on states to develop state plans. These standards are not necessary, in any event, because they are based on what those sources are already doing (i.e., business as usual).

- The major questions doctrine also supports EPA's Alternative Proposal. The 2024 GHG Standards did not remedy the legal deficiencies identified by the U.S. Supreme Court in *West Virginia v. EPA*. Although the 2024 GHG Standards do not require overt generation shifting (with the exception of the 40 percent gas co-firing requirement), they lead to the same result because they are based on technology that is not adequately demonstrated, require compliance with rates that are not achievable, and are not cost-effective.

- EPA needs to reconsider the CO_2 emission standards for new base load combustion turbines in Phase 1 and the standards for intermediate load combustion turbines, and APPA urges the Agency to do so in a supplemental rulemaking.

    - EPA should establish a single, input-based CO_2 emission standard for combustion turbines for all combustion turbines as a matter of policy. The capacity-factor basis for the 2024 GHG Standards for combustion turbines have significant energy and cost implications.

    - If the form of the standard is retained as pounds of carbon dioxide per megawatt-hour (lb CO_2/MWh), then the NSPS for the intermediate load subcategory must be reconsidered.

        - The existing intermediate load standards are unachievable by even highly efficient turbines, and because the standard is based on a single set of operating parameters, it effectively dictates the types of operations and particular uses of the turbine, which is impermissible under the CAA.

        - Even if operational constraints can be the basis of the BSER, the Agency should have established a significantly higher standard for this subcategory.

    - If the form of the standard is retained as lb CO_2/MWh, then the NSPS for the Phase 1 base load subcategory must be reconsidered.

        - The current Phase 1 NSPS for the base load subcategory is deeply flawed because it is unachievable by a number of highly efficient turbines on the market. EPA based the standard on only one unit that is not representative of the variety of highly efficient combustion turbines that are available on the market.

        - Even if operational constraints can be the basis of the BSER, EPA should have established a significantly higher standard for this subcategory.

- EPA's selection of an annual capacity factor of 40 percent as the dividing threshold between simple-cycle combustion turbines and combined-cycle combustion turbines should be eliminated or revised upwards.
    - Combustion turbines operating above a capacity factor of 20 percent should be subcategorized based on their mode of operation (simple cycle and combined cycle) and not on the basis of their utilization.
    - If EPA retains the current intermediate load and base load subcategories, then the demarcation between the two subcategories needs to be increased.

- Although APPA believes the Alternative Proposal offers a more certain and durable option, APPA also offers comments on the Primary Proposal for EPA's consideration in the event EPA decides to finalize it, perhaps after it finalizes the Alternative Proposal.
    - Before listing a new source category under section 111, EPA must find that the category significantly contributes to endangering air pollution.
    - To regulate a pollutant from a listed source category, the Agency must find that emissions of that pollutant from the listed source category significantly contribute to endangering air pollution.

III. In Light of Surging Electricity Demand, Public Power Utilities Need Immediate Relief from the 2024 GHG Standards to Enable Them to Continue Providing Reliable and Affordable Electricity to Their Customers.

During rulemaking on the 2024 GHG Standards, APPA told EPA that the standards "will place further strain on electric reliability, give rise to more health and safety concerns, increase the cost of electricity, and potentially undermine public support for prudent programs aimed at reducing GHGs."[10] APPA was not alone in expressing these concerns. Representatives of the power generation industry warned EPA that the 2024 GHG Standards would threaten both the reliability and affordability of electricity if the Agency finalized them.[11] Grid operators expressed concern that the 2024 GHG Standards "would greatly exacerbate an ongoing loss of critical, dispatchable generating capacity that is needed to ensure reliability,"[12] and states warned

[10] APPA Comments on Proposed 2024 GHG Standards at 7; *see also* APPA Comments on Supplemental Rulemaking for Proposed 2024 GHG Standards at 6 (stating APPA's concern that the Proposed 2024 GHG Standards "will affect the reliability and affordability of electricity").

[11] *See, e.g.*, Comments submitted by the National Rural Electric Cooperative Association at 24, EPA-HQ-OAR-2023-0072-0770 (Aug. 8, 2023) (alerting EPA that the "combination of premature retirements from coal units and (arbitrarily) low capacity factors from natural gas units will exacerbate the reliability issues"); Comments submitted by the Edison Electric Institute at 33, EPA-HQ-OAR-2023-0072-0772 (Aug. 8, 2023) (noting "capacity additions (the vast majority of which are intermittent resources with lesser accredited capacity) are not keeping pace with capacity retirements," which "presents significant near-term risks to system reliability, particularly during extreme events") (EEI Comments); Comments submitted by the Power Generators Air Coalition at 15, EPA-HQ-OAR-2023-0072-0710 (warning EPA that the 2024 GHG Standards "will further strain electric reliability, raise health and safety issues resulting from electric service disruptions, and increase the cost of electricity") (PGen Comments).

[12] Joint Comments submitted by Electric Reliability Council of Texas, Inc., Midcontinent Independent System Operator, Inc. (MISO), PJM Interconnection, L.L.C., and Southwest Power Pool, Inc. (SPP) at 5 (Aug. 8, 2023),

"that the grid reliability is especially fragile" with increasing demands from a growing population, increased reliance on electricity, and data centers and cryptocurrency mining.[13]

EPA's 2024 GHG Standards were finalized despite these serious concerns about energy reliability and despite EPA's obligation under section 111(a)(1) of the CAA to "tak[e] into account … energy requirements" when determining a BSER.[14] Although EPA added two reliability mechanisms to the 2024 GHG Standards that it said would aid in easing reliability concerns,[15] the reliability mechanisms offer little assistance because they provide only short-term relief during emergency events[16] or the possibility of an extension of the retirement date for an EGU by one year.[17] These reliability mechanisms are of no use to an EGU that had to retire because it could not meet the 2024 GHG Standards.

Since the 2024 GHG Standards were proposed, electricity demand has surged, driven by factors like increased electrification and traditional and artificial intelligence (AI) data centers, and it is expected to continue growing at a rapid rate. The EIA recently announced in its *Annual Energy Outlook 2025* Reference case that, it "project[s] the electricity consumed for commercial computing will increase faster than any other end use in buildings. Computing accounted for an estimated 8% of commercial sector electricity consumption in 2024 and grows to 20% by 2050."[18] Recent executive orders have recognized the growth in electricity demand and the risks it poses to the electric grid, including the declaration by the President of a National Energy Emergency.[19]

NERC highlighted the challenges this demand growth poses to grid reliability in its most recent annual Long-Term Reliability Assessment, which NERC issued in December 2024 and

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EPA-HQ-OAR-2023-0072-0673; *see also* Comments submitted by SPP at 8 (Aug. 8, 2023), EPA-HQ-OAR-2023-0072-0670 (noting the 2024 GHG Standards "will jeopardize, through accelerated retirement or reduced output, SPP's ability to utilize [fossil fuel facilities] until such time as adequate clean alternatives are available"); Comments submitted by MISO at 2 (Aug. 8, 2023), EPA-HQ-OAR-2023-0072-0623 (warning about "the risk of a looming [energy] shortfall").

[13] Comments submitted by the Attorneys General of State of West Virginia, et al. at 46, EPA-HQ-OAR-2023-0072-0798 (Aug. 8, 2023).

[14] CAA § 111(a)(1), 42 U.S.C. § 7411(a)(1).

[15] 89 Fed. Reg. at 40,014-20.

[16] *Id.* at 40,015 (providing the opportunity for relief "during an Energy Emergency Alert level 2 or 3 as defined by NERC Reliability Standard EOP-011-2 or its successor").

[17] *Id.* at 40,017 (providing an opportunity for an EGU to "obtain up to a 1-year extension of a cease operation date").

[18] EIA, Electricity use for commercial computing could surpass space cooling, ventilation (June 25, 2025), https://www.eia.gov/todayinenergy/detail.php?id=65564.

[19] *See, e.g.*, Executive Order 14154 of January 20, 2025, Unleashing American Energy, 90 Fed. Reg. 8353 (Jan. 29, 2025); Executive Order 14156 of January 20, 2025, Declaring a National Energy Emergency, 90 Fed. Reg. 8433 (Jan. 29, 2025); Executive Order 14260 of April 8, 2025, Protecting American Energy From State Overreach, 90 Fed. Reg. 15,513 (Apr. 14, 2025).

updated on July 15, 2025.[20] NERC indicates that the growth in electricity demand "is now higher than at any point in the past two decades," with forecasts for peak demand and energy growth continuing to climb over the next ten years.[21] NERC explains that the projections for the bulk power system "for both winter and summer *have increased massively* over the 10-year period,"[22] with summer peak demand expected to rise by 15 percent and winter peak demand by nearly 18 percent over a decade.[23] The organization also warns of resource adequacy challenges due to the retirement of fossil fuel generators and the lag in constructing new resources.[24] Of particular note, NERC says these "*trends point to critical reliability challenges facing the industry*."[25]

RTOs have also echoed reliability concerns due to the implementation of the 2024 GHG Standards.[26] Those reliability concerns include the rapid retirement of fossil fuel-fired generators without firm replacements, dispatchable generation scarcity to back up variable generation, delays in energy infrastructure buildout and permitting, and increased reliance on natural gas without firm gas back up, especially in the winter months when fuel delivery may be vulnerable.

In addition, in energy-only markets like the Electric Reliability Council of Texas (ERCOT), reliability issues become more likely as new natural gas-fired plants do not get built under the 2024 GHG Standards. Load serving entities in ERCOT do not receive cost recovery, whereas other markets allow for cost recovery. But in those markets, even though the new gas-fired plants might be constructed, those costs will likely be passed onto consumers through increased electricity costs.

The 2024 GHG Standards will only worsen these challenges by accelerating the retirement of power plants and reducing the amount of base load generation available in the United States. Retirements of fossil fuel-fired power plants in recent years have already had a negative impact on electric reliability, which can be seen in an exponential increase in requests to the Department of Energy (DOE) seeking relief through emergency orders under section 202(c) of the Federal Power Act that allow compliance with environmental regulations to be suspended when needed to preserve the ability of the electric grid to meet electricity demand. For example,

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[20] NERC, 2024 Long-Term Reliability Assessment (Dec. 2024, updated July 15, 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[21] *Id.* at 8.

[22] *Id.* (emphasis added).

[23] *Id.* at 9.

[24] *Id.* at 6.

[25] *Id.* (emphasis in original).

[26] *See, e.g.*, Brief of Midcontinent Independent System Operator, Inc., PJM Interconnection L.L.C., Southwest Power Pool, Inc., and Electric Reliability Council of Texas, Inc., as *Amici Curiae* in Support of Petitioners, *West Virginia v. EPA*, No. 24-1120 (and consolidated cases), ECF No. 2074675 (D.C. Cir. Sept. 13, 2024). This brief is incorporated herein and included in Addendum 2 to these comments.

over the 20-year period from 2000 to 2019, there were eight emergency orders issued by DOE.[27] Since 2020, however, 18 such orders have been issued, including seven in 2022 alone.[28]

The 2024 GHG Standards also compound reliability issues because they require substantial capital investments to be made in coal-fired units unless they cease operations by January 1, 2032.[29] Units operating whose owners agree to retire them before January 1, 2039, will need to invest in pipeline infrastructure to bring natural gas to the plan for co-firing unless the unit already has access to natural gas (and access to gas in sufficient quantities), and these investments must be completed by January 1, 2030.[30] Any coal-fired unit that wants to operate after 2038 must invest in CCS, with that system being in place and operational by 2032.[31] The significant cost of these investments coupled with aggressive and difficult to meet timelines will increase the number of retirements of these power plants, which provide base load electricity throughout the country.

In addition, the 2024 GHG Standards negatively impact gas-fired generation because they impose capacity factor limitations on new, larger combined cycle combustion turbines. The standards are already having an adverse effect on the ability of electric generators to construct new base load generation to meet increased demand. Under the 2024 GHG Standards, new base load units operating at greater than 40 percent of their capacity factor must comply with Phase 2 emission limits based on 90 percent CCS beginning in 2032.[32] As discussed in detail in Section IV.B.2 of these comments, 90 percent CCS is not adequately demonstrated, the emission limit based on that BSER is not achievable, and it is not cost-effective. But the operating permit for any base load combustion turbine that is constructed now includes this limitation. Even the current Phase 1 emission limits for base load combustion turbines and the emission limits for intermediate load combustion turbines from the 2024 GHG Standards,[33] both of which are currently in effect, pose problems. As discussed in Section V of these comments, most combustion turbines cannot meet the emission limits for these subcategories.

The end result of the 2024 GHG standards is that owners and operators are encountering difficulty in permitting and constructing new combustion turbines, which are needed to meet increasing electricity demand. And even if owners and operators are able to permit and construct a new unit, they must limit their operation to avoid being classified as a base load unit. All these things further strain grid reliability, exacerbate health and safety issues resulting from service disruptions, and raise the cost of electricity.

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[27] *See* DOE, Office of Cybersecurity, Energy Security, and Emergency Response, *DOE's Use of Federal Power Act Emergency Authority – Archived*, https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority-archived.

[28] *See* DOE, Office of Cybersecurity, Energy Security, and Emergency Response, *DOE's Use of Federal Power Act Emergency Authority*, https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority.

[29] 40 C.F.R. §§ 60.5740b(a)(9)(ii).

[30] *See id.* §§ 60.5740b(a)(1)(ii), (a)(3); 60.5775b(c)(2).

[31] *Id.* §§ 60.5740b(a)(1)(i), (a)(3); 60.5775b(c)(1).

[32] *See* Table 1 to Subpart TTTTa of Part 60.

[33] *See id.*

In summary, the 2024 GHG Standards have created obstacles for the power industry to meet rising electricity demand through the construction of new gas-fired units and will result in an acceleration of the retirement of coal-fired units. The Proposed Rule's repeal or revision of the 2024 GHG Standards is needed to help alleviate the serious reliability concerns caused by the standards, particularly in the face of growing energy demands.

IV. The Proposed Rule's Alternative Proposal

In the Proposed Rule, EPA has included an Alternative Proposal that would revise Subpart TTTTa to remove the CCS requirements for new base load combustion turbines in Phase 2 and for coal-fired steam generating units that undergo a large modification.[34] The Proposed Rule would also repeal Subpart UUUUb, the emission guidelines for existing fossil fuel-fired steam generating units.[35] As noted earlier in these comments, if finalized, the Alternative Proposal would remedy the legal defects of the 2024 GHG Standards and provide needed relief to the power industry. Because the Alternative Proposal does not rely on any new interpretations of the CAA and because decades of case law support it, APPA urges EPA to finalize the Alternative Proposal so that the relief the industry needs can be provided with greater certainty.

As discussed in Section III of these comments, the construction of new electric generation is needed to address the rapidly increasing demand for electricity. The 2024 GHG Standards, which remain in effect, are hindering the construction of new EGUs, specifically the construction of new combustion turbines, and the proposed repeal would provide much-needed relief to the power industry. As discussed in detail in Section V of these comments, however, a handful of issues will remain if EPA finalizes the Alternative Proposal, specifically regarding the NSPS for intermediate load combustion turbines and the Phase 1 NSPS for base load combustion turbines. Targeted revisions to those two NSPS are necessary to ensure that those NSPS meet the requirement of section 111 of the CAA that an NSPS be "achievable." APPA therefore requests that EPA issue a supplemental proposed rule that would propose to revise the NSPS for intermediate and base load combustion turbines as soon as possible, or, alternatively, EPA could issue a standalone proposed rule to revise the NSPS if it preferred. Regardless of the path taken, it is important that EPA acts quickly to provide needed relief so that new generation can be constructed to meet increasing electric demand.

The basis for the Alternative Proposal rests on several proposed determinations:

- EPA proposes to determine "that 90 percent CCS is not the BSER for existing long-term coal-fired steam generating units because it has not been adequately demonstrated and because the costs are not reasonable."[36]

- The Agency further proposes to determine that the degree of emission limitation provided by the standard for long-term coal-fired steam generating units is not

[34] 90 Fed. Reg. at 25,768.

[35] *Id.*

[36] *Id.*

achievable "because it is unlikely that the infrastructure necessary for CCS can be deployed by the January 1, 2032, compliance date."[37]

- EPA proposes to repeal "the CCS-based requirements for coal-fired steam generating units undertaking a large modification."[38]

- The Agency proposes to determine that 90 percent CCS is also not BSER for new base load combustion turbine EGUs because "it has not been adequately demonstrated," because "the costs are not reasonable," and because it is not achievable by the compliance date due to infrastructure constraints.[39]

- EPA also proposes to conclude that 40 percent natural gas co-firing is not the BSER for existing medium-term coal-fired steam generating units because consideration of the energy requirements shows that 40 percent natural gas co-firing in a steam generating unit is an inefficient use of natural gas."[40]

A. The Legal Requirements Governing a Standard of Performance under Section 111 of the CAA

Any section 111 performance standard (either for a new source under section 111(b) or an existing source under section 111(d)) must be "achievable" by the regulated sources within the designated source category using the BSER that has been "adequately demonstrated" for the sources covered by the standard, taking into account associated cost and other factors.[41] These requirements are found in section 111(a)(1), which defines a "standard of performance" as:

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.[42]

To develop a standard of performance that meets these requirements, EPA must engage in a three-step analysis, as confirmed by the U.S. Court of Appeals for the District of Columbia Circuit.[43] First, the Agency identifies a system or systems of emission reduction that have been "adequately demonstrated" for the type of source at issue. Second, EPA determines the emission levels that are "achievable" by such sources using the adequately demonstrated system or

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[37] *Id.*

[38] *Id.*

[39] *Id.* at 25,768-69.

[40] *Id.* at 25,768.

[41] CAA § 111(a)(1), 42 U.S.C. 7411(a)(1).

[42] *Id*.

[43] *Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981).

systems.[44] Third, based on these determinations, the Agency must then exercise its discretion to choose an achievable emission level that represents the "best" balance of economic, environmental, and energy considerations.[45] The following sections of these comments describe these fundamental requirements in greater detail.

1. "Adequately Demonstrated"

An adequately demonstrated system is one that has an operational history that shows more than mere technical feasibility. It must be dependable and effective, available at a reasonable cost for individual sources, and based on actual operating experience within the source category or at sufficiently similar sources.[46]

EPA has some discretion to extrapolate from other industries in determining whether a technology demonstrated in one industry is adequately demonstrated for another industry – but there are important limitations on that discretion.[47] The Agency may look to the use of a technology in another industry only if that exercise will produce information that is also sufficiently representative of operations in the industry that will be regulated.[48] Similarly, any extrapolations from one industry to another are "subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry" or "mere speculation or conjecture."[49] Further, because NSPS are effective upon proposal, they provide no lead time for technology development, which also constrains the adequate demonstration concept by making clear that the demonstration must be current, not conjectural.

To be adequately demonstrated for all sources within a category or subcategory, a technology must be available for each source type to which the standard will apply.[50] In other words, it must be universally available. To assess this aspect of the adequate demonstration requirement, courts consider various factors such as whether: (i) a sufficient degree of successful implementation has been achieved at full-scale facilities; (ii) data from prototype facilities or other industries are sufficiently representative to warrant application to the source category generally; (iii) there is sufficient experience with all fuel types; and (iv) there are still unresolved issues regarding waste disposal or other harmful environmental effects.[51]

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[44] *See Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973).

[45] *Sierra Club*, 657 F.2d at 330.

[46] *Essex Chem. Corp.*, 486 F.2d at 433; *NRDC v. Thomas*, 805 F.2d 410, 428 n.30 (D.C. Cir. 1986).

[47] *See Lignite Energy Council v. EPA*, 198 F.3d 930, 934 (D.C. Cir. 1999); *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973).

[48] *Lignite Energy Council*, 198 F.3d at 934.

[49] *Portland Cement Ass'n*, 486 at 391; *see also id.* at 389 ("The essential question is whether the mandated standards can be met by a particular industry for which they are set, and this can typically be decided on the basis of information concerning that industry alone."); *Lignite Energy Council*, 198 F.3d at 934.

[50] *See* 70 Fed. Reg. 9706, 9712, 9714, 9715 (Feb. 28, 2005) (rejecting certain technology as BSER in part because of the unavailability of these options across source types to which the performance standards would apply).

[51] *Lignite Energy Council*, 198 F.3d at 934; *Sierra Club*, 657 F.2d at 341 n.157; *Essex Chem. Corp.*, 486 F.2d at

2. "Achievable"

After determining a system has been "adequately demonstrated," EPA must next determine the emission levels that are "achievable" by the individual sources that make use of the system. The performance standard must be achievable under the range of relevant conditions that may affect the emissions to be regulated, including under the most adverse conditions that are expected to recur.[52] The standard must be achievable "for the industry as a whole" and not just for a subset of sources.[53] As with determining whether a technology is adequately demonstrated, EPA may not base its determination that a standard is achievable on "mere speculation or conjecture."[54]

Case law interpreting this requirement provides additional color to the inquiry that the Agency must undertake. Based on those rulings, EPA must "(1) identify variable conditions that might contribute to the amount of expected emissions, and (2) establish that the test data relied on by the agency are representative of potential industry-wide performance, given the range of variables that affect the achievability of the standard."[55]

In other words, to demonstrate achievability, EPA must comprehensively account for variation among sources within the regulated category that could affect emission levels. A demonstration will not be deemed sufficient if the Agency relies on limited test data from a narrow sample of sources or data that does not take the full range of relevant conditions—like source type, feedstock or fuel type, and regional variations—into account.[56] All of these factors combined mean that an NSPS "establishes what every source can achieve, not the best that a source could do."[57] It is intended to represent the "least common denominator" of control standards that can "be reasonably achieved by [a] new source anywhere in the nation."[58]

3. Consideration of statutory factors for "best" adequately demonstrated system

After identifying the emission levels achievable through the use of adequately demonstrated technology, EPA must then, pursuant to the statute, determine a standard from the range of demonstrated technologies that is "best." In other words, the Agency must choose the standard that "represents the best balance of economic, environmental, and energy

438-39.

[52] *Nat'l Lime Ass'n v. EPA*, 627 F.2d at 431 n.46, 433.

[53] *Id.* at 431.

[54] *Lignite Energy Council*, 198 F.3d at 934.

[55] *Sierra Club*, 657 F.2d at 377 (citing *Nat'l Lime Ass'n*, 627 F.2d at 433).

[56] *See, e.g.*, *Nat'l Lime Ass'n*, 627 F.2d at 432, 435-42; *see also Portland Cement Ass'n*, 486 F.2d at 396, 402.

[57] Letter from Gary McCutchen, Chief, New Source Review Section, EPA Office of Air Quality Planning and Standards, to Richard E. Grusnick, Chief, Air Division, Ala. Dep't of Envtl. Mgmt. at 1 (July 28, 1987), https://www.epa.gov/sites/production/files/2015-07/documents/crucial.pdf (McCutchen Letter).

[58] *Id*.

considerations."[59] To do this, EPA must consider the statutory factors of cost and any nonair quality health and environmental impact and energy requirements.[60] The Agency may also consider a proposed standard's projected emission reductions and its potential to encourage (rather than mandate) technological innovation.[61]

In determining BSER, EPA must ensure that standards do not give a competitive advantage to one state over another.[62] For example, water intensive technology could not be selected as BSER because while it might be "best" in the East, it would have had the effect of precluding construction of new sources in the West.[63] Accordingly, EPA must carefully evaluate and select technologies that are suitable for different regions and do not disadvantage certain states in attracting industries.

The Agency must account for these factors at the plant level and may also consider them "at the national and regional levels and over time."[64] EPA cannot, however, consider costs and environmental or energy impacts at the national level while overlooking these impacts at the level of individual sources. Indeed, the D.C. Circuit made clear in *Sierra Club* that the CAA authorizes EPA to examine the national scale in addition to—not instead of—assessing a standard's impact on individual sources.[65] Accordingly, EPA cannot set a standard based on national-scale considerations that would impose unreasonable costs, environmental impacts, or energy requirements at the level of individual plants.

B. The Portions of the 2024 GHG Standards that Rely on 90 Percent CCS Do Not Comply with Section 111's Requirements, and EPA Properly Proposes to Repeal Them (C-16, C-33[66]).

While a developing technology, CCS has not yet met the legal threshold to be considered a BSER. Even though the technology is making advancements through a variety of pilot projects (discussed further below), it cannot yet be determined to be "adequately demonstrated." There is insufficient experience with CCS in commercial duty to find that the technology is currently feasible or reliable for widespread application. And even if the technology was ready for more widespread deployment—which it is not—several issues remain that technological development cannot resolve, including geographical constraints, access to water, parasitic load, infrastructure development, and cost.

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[59] *Sierra Club*, 657 F.2d at 330.

[60] CAA § 111(a)(1).

[61] *Sierra Club*, 657 F.2d at 326, 347.

[62] *Id*. at 325.

[63] *Id.* at 330.

[64] *Id*.

[65] *Id*.

[66] "C" references, which are placed in various headings throughout these comments, refer to the numbers EPA gave to specific issues on which it is soliciting comment in the Proposed Rule. *See* 90 Fed. Reg. at 25,777-79.

In the Proposed Rule, EPA properly recognizes that 90 percent CCS does not meet the legal requirements of section 111 to be considered a BSER. As the Agency proposes to find in the Proposed Rule, 90 percent CCS is not adequately demonstrated at fossil fuel-fired EGUs, the emission standards based on it are not achievable, and it is not a cost-effective technology.[67] In addition, there are other factors that preclude 90 percent CCS from being the BSER for fossil fuel-fired EGUs. Each of these is discussed in turn below:

1. CCS is not adequately demonstrated at stationary combustion turbines (C-34, C-35).

For stationary combustion turbines, the universe of projects that EPA previously cited to support its adequate demonstration finding in the 2024 GHG Standards, in fact, support the opposite conclusions as the Agency now appropriately recognizes in the Proposed Rule. As APPA has discussed in its comments on the 2024 GHG Standards, in establishing those standards, EPA improperly relied on the Bellingham Energy Center in Massachusetts and the Peterhead Power Station in Scotland as support for an adequate demonstration determination. But neither of these projects support such a finding.

At the Bellingham Energy Center, CCS was applied to an existing combined cycle turbine, and the 40 MW slipstream capture facility, which operated from 1991 to 2005, captured 85 to 95 percent of the CO_2 in the slipstream for use in the food industry.[68] This slipstream capture facility is not comparable to the amount of capture that is required at large fossil fuel-fired EGUs.[69] Moreover, "[o]perating CCUS or any environmental control process as a 'slipstream' of gas, in contrast to being inseparably linked to the host unit, provides flexibility to manage uncertainties."[70] Specifically, a slipstream "avoid[s] issues with load ramping up or down, startup/shutdown, or process 'upsets.'"[71] Success at a slipstream is not comparable to the dynamic actions that occur at an EGU and is therefore not indicative of future success at an EGU.[72]

The second project EPA relied on for its BSER determination for combustion turbines is the Peterhead Power Station in Scotland. That facility "is in the planning stages of development" and is not yet operational.[73] To be adequately demonstrated, a technology must have been put into actual operation or there can be no reasonable basis to determinate that the technology is "reasonably reliable, reasonably efficient, and … reasonably … expected to serve the interests of

[67] *Id.* at 25,769.

[68] *See* 89 Fed. Reg. at 39,926.

[69] J.E. Cichanowicz, M.C. Hein, Analysis of Carbon Capture Utilization and Sequestration Technology As BSER and New Source Performance Standards Under the 2024 Greenhouse Gas (GHG) for Fossil-Fired EGUs at 4 (Aug. 2025) (noting the gas turbine at Bellingham is only about 1/6th that of a J- or H-Class Frame turbine) (APPA 2025 CCS Technical Report) (included as Attachment 1 to these comments).

[70] *Id.*

[71] *Id.*

[72] *Id.* at 6.

[73] 89 Fed. Reg. at 39,927.

pollution control without becoming exorbitantly costly in an economic or environmental way."[74] Because the Peterhead Power Station is not yet in operation, it cannot serve as a proper basis to claim that CCS is an adequately demonstrated technology.

In addition to these two projects on which EPA primarily relied, it also cited a number of similar projects that are likewise non-operational—and in some cases not even constructed. Further, a number of these additional projects were funded under the Energy Policy Act of 2005 (EPAct05). EPAct05 explicitly prohibits EPA from relying on projects that received EPAct05 funds in determining whether a technology is adequately demonstrated under section 111. EPAct05 states that "[n]o technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be [] adequately demonstrated for purposes of section 111 of the Clean Air Act."[75] Because Congress makes clear that the Agency is prohibited from using EPAct05-funded projects as a basis for claiming a technology is adequately demonstrated, EPA's reliance on such a project—even simply "to support or corroborate other information that supports such a determination"[76]—is impermissible.

2. CCS is not adequately demonstrated for steam-generating units (C-17, C-18, C-19, C-20).

The projects cited as support for the adequate demonstration of CCS for coal-fired steam generating units in the 2024 GHG Standards do not support an such a determination. EPA's determination in the 2024 GHG Standards that CCS is adequately demonstrated relied primarily on a single project at a coal-fired steam generating unit (SaskPower's Boundary Dam Unit 3 project).[77] The Agency also cited some slipstream power plant projects (Plant Barry,[78] Petra Nova,[79] AES's Warrior Run and Shady Point plants,[80] and the Argus Cogeneration Plan[81]), most of which received EPAct05 funding, as additional support. As discussed below, none of the projects cited by EPA in the 2024 GHG Standards provides the requisite level of support for an adequate demonstration, and the Agency is correct to reverse course now.

The SaskPower Boundary Dam Unit 3 project in Saskatchewan, Canada, has experienced numerous problems and does not support EPA's adequately demonstrated determination. But Boundary Dam has never demonstrated 90 percent capture of CO_2. As EPA notes in the

[74] *Essex Chem. Corp.*, 486 F.2d at 433; *see also NRDC v. Thomas*, 805 F.2d at 428 n.30.

[75] EPAct05 § 402(i), 42 U.S.C. § 15962(a). Similar EPAct05 language was codified in the Internal Revenue Code and restricts EPA from considering technology that received tax credits under the EPAct05. *Id.* § 1307(b), 26 U.S.C. § 48A(g); *see also* 89 Fed. Reg. at 39,878-79 n.613.

[76] 89 Fed. Reg. at 39,855.

[77] 90 Fed. Reg. at 25,769.

[78] 89 Fed. Reg. at 39,850. Plant Barry received EPAct05 funds. *See id.* at 39,849 (heading for EPAct05 assisted projects, with Plant Barry listed therein); *see also* 90 Fed. Reg. at 25,770.

[79] 89 Fed. Reg. at 39,849-50; 90 Fed. Reg. at 25,770-71. Petra Nova received EPAct05 funds. 89 Fed. Reg. at 39,849; 90 Fed. Reg. at 25,770.

[80] 89 Fed. Reg. at 39,849; 90 Fed. Reg. at 25,770.

[81] 89 Fed. Reg. at 39,849; 90 Fed. Reg. at 25,770.

Proposed Rule, "[w]hile Boundary Dam Unit 3 achieved 89.7 percent capture over a 3-day test early in its operation, longer-term capture levels have been lower," with the unit "achiev[ing] a total capture efficiency of not more than 63 percent in a calendar year" between 2015 and 2022.[82] Indeed, the operator of Boundary Dam Unit 3 filed comments on EPA's Proposed GHG Standards to make clear that "SaskPower's CCS facility *is not capturing 90 per cent* of emissions from Boundary Dam Unit 3."[83] Boundary Dam's operator acknowledged that Unit 3 has experienced constant "technical issues," requiring "consistent[] … modifications … to stabilize operations" and "improve reliability."[84] Indeed, Boundary Dam's operator "concedes that a fraction of the flue gas from the Unit 3 boiler is not processed but bypassed – for the purpose of reliability. The fraction of flue gas bypassed is 5% of total flow."[85] As APPA's expert consultants determined, the "Boundary Dam experience does not demonstrate CO_2 removal of 90% -- but, rather 65-70% CO_2 can be achieved with a caveat on reliability."[86] These facts and this poor performance cannot support a demonstration that 90 percent CCS is adequately demonstrated.

Further, it is important to note that the project itself is located at a relatively small 110 MW power plant that is not representative of the challenges that would be faced at a much larger scale. Demonstration at the appropriate scale and under real-world conditions, including challenging conditions, are necessary to support adequate demonstration. Because the 2024 GHG Standards incorporate 90 percent CCS requirements for long-term coal-fired steam generating units (i.e., those that will operate after January 1, 2039) and for coal-fired steam generating units that undergo a large modification, they are highly likely to only be large units that run frequently, meaning that they are not comparable to Boundary Dam.

EPA also relied on CCS at the Argus Cogeneration Plant to support its adequately demonstrated determination.[87] That facility captures about "270,000 metric tons of CO_2 per year from the flue gas of the bituminous coal-fired steam generating units at the 63 MW" plant.[88] Crucially, however, the Agency never provided information about the percentage of CCS achieved by the facility. The best information available, however, shows that Argus captures far less than 90 percent of the CO_2 generated onsite, perhaps as much as 33 percent and perhaps as little as 18 percent.[89] Further, this facility does not transport or store the CO_2 it does capture,

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[82] 90 Fed. Reg. at 25,769-70.

[83] SaskPower Comments on Proposed 2024 GHG Standards at 1, Docket ID No. EPA-HQ-OAR-2023-0072-0687 (Aug. 4, 2023) (emphasis added).

[84] *Id.*

[85] APPA 2025 CCS Technical Report at 12.

[86] *Id.*

[87] 89 Fed. Reg. at 39,849.

[88] *Id.*

[89] *See* J.P. Kay, et al., Energy & Environmental Research Center, University of North Dakota, Examination of EPA's Proposed Emission Guidelines Under 40 CFR Part 60 at 5 (Aug. 2023) (estimating 18% capture rate for the station) (Attachment C to the Comments of the Power Generators Air Coalition on the proposed 2024 GHG Standards, Docket ID No. EPA-HQ-OAR-2023-0072-0710 (Aug. 8, 2023)); J.E. Cichanowicz, M.C. Hein, Technical Comments on Carbon Capture Utilization and Sequestration Aspects of the Proposed New Source Performance Standards for GHG Emissions from New and Reconstructed EGUs; Emission Guidelines for GHG

which EPA's standard requires.[90] Accordingly, this example does not support an adequate demonstration finding.

Two additional projects that EPA relied on for its adequate demonstration finding are AES Warrior Run and AES Shady Point, which are both slipstream facilities. These slipstream projects are intended for research and development, but crucially, they do "not link the reliability of the host process to the CO_2 capture technology—and thus cannot reflect conditions for 24x7 utility power generation demonstration."[91] Just as important, neither project captures anywhere near 90 percent of the CO_2 generated onsite. Warrior Run, which is a 180 MW unit, captures only about 10 percent of its CO_2 emissions[92] and Shady Point, which is a 320 MW unit, captures only about 5 percent.[93] Neither of these projects can be credibly cited as evidence that 90 percent CCS is adequately demonstrated.

EPA also cited several other projects as support for its previous adequate demonstration finding. It relied on CCS projects at Petra Nova and Plant Barry, for instance, both of which received funding under EPAct05, which renders them off-limits for regulatory purposes under section 111. Even if they can be considered as "corroboration,"[94] however, they would still fail to provide suitable support. Petra Nova, for instance, is another slipstream project, meaning it "does not reflect actual, full-scale duty if integrated into the host boiler duty cycle."[95] Petra Nova has also faced many problems.[96] As the Agency noted in the 2024 GHG Standards that Petra Nova "successfully captured 92.4 percent of the CO_2 *from the slip stream of flue gas*."[97] This does not mean that Petra Nova supports an adequately demonstrated determination for 90% CCS. Because the capture system was used on a slip stream – which represents only a portion of the unit's emissions – the reality is that Petra Nova captured only 33 percent of the unit's CO_2 emissions,[98] which is far below the 2024 GHG Standard's 90 percent requirement.

Emissions from Existing EGUs; and Repeal of the Affordable Clean Energy Rule at 3 (Aug. 27, 2023) (estimating 33% capture rate for single facility at the station) (APPA 2023 CCS Technical Report) (included as Attachment 2 to APPA Comments on Proposed 2024 GHG Standards).

[90] TSD - Greenhouse Gas Mitigation Measures for Steam Generating Units, New Source Performance Standards for Greenhouse Gas Emissions from New and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emissions Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule at 37-38 (Apr. 2024), Docket ID EPA-HQ-OAR-2023-0072-9095.

[91] APPA 2023 CCS Technical Report at 3 n.7.

[92] 89 Fed. Reg. at 39,849.

[93] *Id.*

[94] *See id.* at 39,855.

[95] APPA 2025 CCS Technical Report at 13.

[96] *See* N. Groom, Reuters, *Problems plagued U.S. CO2 capture project before shutdown: document* (Aug. 6, 2020), https://www.reuters.com/article/us-usa-energy-carbon-capture/problems-plagued-u-s-co2-capture-project-beforeshutdown-document-idUSKCN2523K8.

[97] 89 Fed. Reg. at 39,850 (emphasis added).

[98] EEI Comments at 72.

Likewise, EPA mischaracterized Plant Barry in the 2024 GHG Standards when it cited this plant as an example of a "fully integrated 25 [MW] CCS project with a capture rate of 90 percent."[99] Once again, this is a slipstream CCS project that captures just a *fraction* of the CO_2 output of *one facility*.[100] This example is not of the scale or types to make it useful for or anywhere near comparable to the facilities to which the standard applies, meaning it cannot support an adequate demonstration finding, and EPA is correct in the Proposed Rule to state that "Plant Barry is not reflective of commercial scale operation."[101]

In the 2024 GHG Standards, EPA also improperly relied on projects that have not even been constructed to support adequate demonstration. It should be self-evident that section 111 of the CAA does not allow unconstructed projects to provide evidence a technology is adequately demonstrated. Even then, a closer look at some of these unconstructed projects shows that even they would not support a determination that 90 percent CCS is adequately demonstrated. Project Tundra, for instance, *if built*, would attempt to demonstrate a 70 percent CCS system—a feat that has still not been achieved there or anywhere.[102]

Finally, EPA cited "vendor statements" to support its 90 percent CCS adequate demonstration determination.[103] The D.C. Circuit, however, has made clear that vendor statements, while informative cannot serve as the basis for an adequate demonstration finding: stating that "their support for the standard, taken alone, would not be decisive."[104]

3. EPA correctly proposes to find that the performance standards in the 2024 GHG Standards that are based on 90 percent CCS are not achievable (C-23, C-39).

Throughout the history of section 111, EPA has held the position that a standard of performance "establishes what every source can achieve" and is intended to represent the "least common denominator" that can "be reasonably achieved by [a] new source anywhere in the nation.[105] "To be achievable, … a uniform standard must be capable of being met under *most adverse* conditions which can reasonably be expected to recur."[106] Put differently, emission limits are not achievable when, "by design, there are no particular controls a … plant operator

[99] 89 Fed. Reg. at 39,850.

[100] PGen Comments at 26-27, 34.

[101] 90 Fed. Reg. at 25,770.

[102] Comments from Minnkota Power Cooperative, Inc. on 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 at 12 (Aug. 8, 2023), Docket ID EPA-HQ-OAR-2023-0072-0632.

[103] 89 Fed. Reg. at 39,851-52.

[104] *Sierra Club*, 657 F.2d at 364.

[105] McCutchen Letter at 1.

[106] *Nat'l Lime Ass'n*, 627 F.2d at 431 n.46 (emphasis added).

can install and operate to attain the emissions limits."[107] EPA cannot look only to the *most favorable* conditions and claim its emission limitations are achievable.

As an initial matter, no commercial EGU has ever achieved 90 percent CCS on a sustained basis, as the 2024 GHG Standards require, and EPA cites not a single example of a facility meeting this standard in the 2024 GHG Standards. This alone disqualifies 90 percent CCS as being a permissible BSER. In the Proposed Rule, EPA notes that it "is addressing only CCS with 90 percent capture, because that was the BSER determination in the [2024 GHG Standards]."[108] EPA says it is not examining "[w]hether CCS with other, lower rates of capture could be the BSER" because that "is outside the scope of this repeal action."[109] As discussed below, however, other reasons also exist to support EPA's determination in the Proposed Rule that CCS is not achievable as required by section 111, and these reasons continue to be relevant at lower CO_2 capture rates.

In addition, as EPA explains in the Proposed Rule, the infrastructure needed for CCS, which includes pipelines and storage facilities, does not exist, and the timelines provided in the 2024 GHG Standards are not sufficient to ensure that the infrastructure can be constructed by the compliance deadlines in the 2024 GHG Standards.[110]

As the Agency admitted in the 2024 GHG Standards, many areas of the country do not have convenient access to geologic storage for CCS. EPA's assessment "found that there are 43 states with access to, or are within 100 [kilometers] [62 miles] from, onshore or offshore storage in deep saline formations, unmineable coal seams, and depleted oil and gas reservoirs."[111] Under the Agency's own facts, this means that in seven states, the owners and operators of EGUs will need to construct a pipeline that is at least 62 miles long. However, the cost to construct a pipeline is very expensive, involving a years-long permitting process, and pipelines are met with increasing resistance making permitting in many cases impossible.[112]

EPA's "solution" to this achievability problem is to suggest that "[e]lectricity demand in areas that may not have geologic sequestration sites may be served by gas-fired EGUs that are built in areas with geologic sequestration, and the generated electricity can be delivered through transmission lines to the load areas through 'gas-by-wire.'"[113] While this might be conceivable for new EGUs, EPA's proposition has two significant flaws. First, constructing transmission

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[107] *West Virginia v. EPA*, 597 U.S. 697, 701 (2022).

[108] 90 Fed. Reg. at 25,773.

[109] *Id.*

[110] *Id.* (coal-fired steam generating units); *id.* at 25,777 (base load combustion turbines).

[111] 89 Fed. Reg. at 39,930.

[112] *See, e.g.*, I. Penn, NY TIMES, *Atlantic Coast Pipeline Canceled as Delays and Costs Mount* (July 5, 2020), https://www.nytimes.com/2020/07/05/business/atlantic-coast-pipeline-cancel-dominion-energy-berkshire-hathaway.html; C. Davenport, NY TIMES, *Mountain Valley Pipeline Halted as Legal Wrangling Heats Up* (July 12, 2023), https://www.nytimes.com/2023/07/12/climate/mountain-valley-pipeline-courts.html; A. Liptak and A. VanSickle, NY TIMES, *Supreme Court Clears the Way for Pipeline as Appeal Moves Forward* (July 27, 2023), https://www.nytimes.com/2023/07/27/us/supreme-court-mountain-valley-pipeline.html.

[113] 89 Fed. Reg. at 39,931.

lines is also expensive, takes years to permit, and is often met with public resistance. Second, and more importantly, this "give[s] a competitive advantage to one State over another in attracting industry," in violation of section 111.[114] And this "solution" is completely unworkable for existing EGUs, unless the owner or operator wants to prematurely retire an EGU and construct a new one near geologic storage.

According to a recent Congressional Research Service report, which is cited by EPA on this issue,[115] there are currently approximately 5,000 miles of pipelines in the United States capable to transport CO_2.[116] However, this is merely a small fraction of what is needed to meet GHG reduction goals. The report noted a recent study suggesting that achieving national goals for GHG reduction would require an additional 66,000 miles of pipelines by 2050, at a cost of "some $170 billion in new capital investment."[117] The Agency glosses over the difficulties and hurdles involved in constructing this pipeline network in the 2024 GHG Standards. Furthermore, EPA downplays safety issues for these pipelines, with a brief mention of a CO_2 pipeline failure in Satartia, Mississippi in 2020 and a statement and that the Pipeline Hazardous Materials Safety Administration is conducting a rulemaking on safety issues.[118] Rather, the Agency merely asserts in a conclusory fashion that state and federal pipeline safety standards "ensure that captured CO_2 will be securely conveyed to a sequestration site."[119]

For all these reasons, EPA's proposed determination that CCS with a 90 percent capture rate is achievable across the nation as a whole is arbitrary, capricious, and unlawful.

4. EPA correctly proposes to find that 90 % CCS is not cost-effective (C-15, C-21, C-22, C-37, C-38).

In establishing NSPS and the emission reduction associated with the BSER, EPA must "tak[e] into account the cost of achieving such reduction."[120] The Agency and courts have long admitted that this means that EPA cannot require measures that come at an "'excessive' or 'unreason-able'" cost.[121] CCS is prohibitively costly, and it is not "rational" for EPA "to impose billions of dollars in economic costs in return for a few dollars in … environmental benefits."[122] On this basis, EPA consistently rejected CCS as too costly in past rulemakings. In the Clean Power Plan, for instance, EPA rejected CCS on the ground that it would be "substantially more expensive" than the multibillion dollar generation shifting approach included in that rule.[123] And

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[114] *Sierra Club*, 657 F.2d at 325.

[115] 90 Fed. Reg. at 25,773.

[116] Congressional Research Service, Carbon Dioxide Pipelines: Safety Issues at 1 (June 3, 2022).

[117] *Id.*

[118] 89 Fed. Reg. at 39,861.

[119] *Id.*

[120] CAA § 111(a)(1), 42 U.S.C. § 7411(a)(1).

[121] 89 Fed. Reg. at 39,832 (quoting *Sierra Club*, 657 F.2d at 343); 90 Fed. Reg. at 25,758 (same quote).

[122] *Michigan v. EPA*, 576 U.S. 743, 752 (2015).

[123] 80 Fed. Reg. 64,662, 64,769 (Oct. 23, 2015).

four years later, EPA's assessment remained unchanged in the Affordable Clean Energy Rule, where the Agency confirmed "the high cost of CCS, including the high capital costs of purchasing and installing CCS technology and the high costs of operating it, … prevent CCS or partial CCS from qualifying" as a permissible system under section 111.[124]

In an attempt to find CCS cost-effective in the 2024 GHG Standards, EPA inappropriately relied on tax credits included in the Inflation Reduction Act (IRA).[125] But tax credits do not *reduce* the costs of CCS; they *transfer* them from power plant owners to taxpayers. Nothing in the CAA says that section 111's cost-effectiveness test is limited only to the costs a source's owner or operator will bear.

Moreover, even if tax credits could be taken into account in the cost-effectiveness analysis, they are not guaranteed. The IRA has significant conditions on the ability to obtain them,[126] and nothing prevents Congress from taking them away. Indeed, this has been recently considered by Congress. Representative Scott Perry introduced a bill on March 6, 2025, called the "45Q Repeal Act of 2025" that would have repealed all of the IRA's tax credits for CCS.[127] Although the CCS tax credits were ultimately preserved in the recently enacted One Big Beautiful Bill (OBBB) Act, this was not without controversy, and nothing prevents a future Congress from repealing the credits in the future. While the 45Q tax credit received relatively favorable treatment under the OBBB Act compared to other credits, most other credits were significantly scaled back, which further weakens EPA's rationale.

5. Other obstacles exist that prevent CCS from being considered as a "best" system to reduce GHG emissions from fossil fuel-fired EGUs.

To be considered the "best" system of emission reduction, other considerations must also support the system's deployment on a nationwide basis. Indeed, EPA must reasonably find that the system "represents the best balance of economic, environmental, and energy considerations."[128] The balance of these additional considerations weighs heavily against CCS as BSER. CCS "give[s] a competitive advantage to one State over another"[129] due to the lack of geological storage across the nation, the fact that CCS is a water intensive technology that has a large parasitic load, and the fact that it imposes unreasonable costs at the level of individual plants.

[124] 84 Fed. Reg. 32,520, 32,548 (July 8, 2019).

[125] 89 Fed. Reg. at 39,882.

[126] An electric generating facility must capture a minimum of 18,750 tons of CO_2 per year and its capture design capacity must be at least 75 percent of the unit's baseline CO_2 production to be eligible for tax credits under the IRA. Pub. L. No. 117-169, § 13104(a).

[127] H.R. 1946, 119th Cong. (Mar. 6, 2025).

[128] *Sierra Club*, 657 F.2d at 330.

[129] *Id.* at 325.

a. Geographic and site limitations

Geographic and site limitations prevent CCS from being considered the "best" system. CCS relies on suitable geological formations, like deep saline reservoirs, for underground storage of captured CO_2, which are not readily accessed in many parts of the country. DOE and U.S. Geological Survey (USGS) surveys have shown potential CO_2 repository sites are unevenly distributed throughout the United States, and many locations across the country lack suitable geological conditions for carbon storage.[130] Of the sites that do exist, approximately two-thirds are concentrated in the Coastal Plains region, with 91 percent of that total limited to a single basin.[131] Alaska holds a tenth of the nation's potential storage capacity, almost all of which is confined to the remote North Slope.[132] In contrast, the entire Eastern Mesozoic Rift Basin region, which includes several major metropolitan areas along the Eastern seaboard, contains less than one percent of the nation's storage capacity.[133] These limitations are not consistent with a "best" system of emission reduction.

Even areas with potentially suitable sites have no guarantee those sites will ultimately be adequate for large-scale CO_2 sequestration after they are examined more closely. Such site-specific evaluations are a costly and complex undertaking, and a comprehensive, nationwide assessment has never been completed. The information that is available, however, demonstrates that the record does not support a finding that CCS is the "best" system. For instance, the DOE's North American Carbon Storage Atlas, states that "[i]t is important that a regionally extensive confining zone (often referred to as caprock) overlies the porous rock layer and that no major faults exist."[134] The North American Carbon Storage Atlas also explains that CO_2 storage capacity, or "injectivity," and the ability of the porous rock to permanently trap CO_2 must also be evaluated. All these criteria are necessary to determine if a site is suitable for use.[135] Other site-specific factors such as land-management or regulatory restrictions, or whether the basin contains freshwater that would restrict its use for CO_2 storage, must also be considered.[136]

The estimates provided in the DOE and USGS reports are "high level," subject to uncertainty, and are not themselves suitable for demonstrating that CCS is the "best" system of emission reduction. Actual storage capacity is likely to be significantly lower than the estimates presented in these studies. USGS researchers themselves have stated that "it is likely that only a fraction" of the high-level estimated technically accessible CO_2 storage resources could be

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[130] *See* DOE, National Energy Technology Laboratory, *Carbon Storage Atlas and Data Resources*, https://netl.doe.gov/carbon-management/carbon-storage/atlas-data (NETL Carbon Storage Atlas); U.S. Department of the Interior, U.S. Geological Survey, Circular 1386, Version 1.1, *National Assessment of Geologic Carbon Dioxide Storage Resources—Results* (Sept. 2013), https://pubs.usgs.gov/circ/1386/pdf/circular1386_508.pdf (USGS National Assessment).

[131] USGS National Assessment at 3 (Fig. 1), 15.

[132] *Id*.

[133] *Id.* at 3 (Fig 1).

[134] *The North American Carbon Storage Atlas – 2012* (First Edition), Slide 18, https://www.slideshare.net/dove000/nacsa2012webversion-43472232 (North American Carbon Storage Atlas).

[135] *Id*.

[136] USGS National Assessment at 15.

available due to issues such as reservoir pressure limitations, boundaries on migration of CO_2, and acceptable injection rates over time.[137] A host of issues must be still be evaluated, including:

- Fractures in the caprock;
- Well penetrations;
- Low permeability despite sufficient porosity;
- Whether CO_2 is likely to settle in a broad or narrow depth range; and
- How the CO_2 plume will spread and to address the displacement of underground fluids property rights that must be pre-arranged for sequestration.

Characterizing and understanding all these issues require costly, time-consuming research and resolution that takes years. If the site proves to be unsuitable for storage after a company has invested years of effort and millions of dollars into the evaluation, the company may have to restart the process all over again with additional time and money.

An example illustrates this considerable risk. One effort to investigate suitable sites in the Colorado Plateau region[138] examined five candidate locations before eventually settling on an area near Holbrook, Arizona. The effort began in the early 2000s and included outreach to the local community, obtaining all necessary permits, and initial drilling over the course of 2007 to 2009. These tasks were completed at a cost of over $5.7 million, but nevertheless the project participants ultimately found that the geological formation had insufficient permeability to proceed with CO_2 injection, and the project had to be abandoned.[139]

Similar problems characterize sites for enhanced oil recovery (EOR), with suitable locations being limited and unevenly distributed across the country. DOE estimates that overall EOR capacity for captured CO_2 is only about 10 percent of the capacity estimated for deep saline sequestration.[140] Additional subsurface feature characterization may be required for several years before a site can be assessed as suitable for EOR. These limits are particularly significant because the only commercial utility applications of CCS to date that could be cost-justified have had to rely on EOR. The reliance on EOR, however, renders the operation volatile—as can be

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[137] *See* Steven T. Anderson, *Cost Implications of Uncertainty in CO_2 Storage Resource Estimates: A Review*, 26:2 NATIONAL RESOURCES RESEARCH 137-59 (Apr. 2017), https://link.springer.com/article/10.1007/s11053-016-9310-7; Steven T. Anderson, *Risk, Liability, and Economic Issues with Long-Term CO_2 Storage—A Review*, 26:1 NATURAL RESOURCES RESEARCH 89-112 (Jan. 2017), https://link.springer.com/article/10.1007/s11053-016-9303-6.

[138] DOE provided 80.5 percent of the overall funding for this project. *See* West Coast Regional Carbon Sequestration Partnership (WESTCARB), *Factsheet for Partnership Field Validation Test (Rev. 10-28-09)* at 5, http://www.westcarb.org/pdfs/FACTSHEET_AZPilot.pdf.

[139] *See* WESTCARB, "Arizona Utilities CO_2 Storage Pilot—Cholla Site," http://www.westcarb.org/AZ_pilot_cholla.html.

[140] North American Carbon Storage Atlas at slide 25 (estimating that 250 billion tons of CO_2 can be used for EOR and thus stored, which is about 10% of the capacity estimated for deep saline sequestration).

seen from the Petra Nova project in Texas, which ceased operations because of an economic downturn at the beginning of the COVID-19 pandemic.[141]

Additionally, the geographic constraints described above cannot readily be addressed by the construction of pipelines to transport separated CO_2 to storage areas may be feasible. Serious obstacles to pipeline construction exist, including expense and significant opposition from the public and interest groups. Indeed, in one example, the Summit Carbon Solutions pipeline project that if approved, will transport CO_2 from a five-state region (Iowa, Minnesota, North Dakota, South Dakota, and Nebraska) to North Dakota, where it will be permanently stored—is estimated to cost $8.9 billion.[142] But the likelihood that this pipeline will be built has been called into serious question, with South Dakota denying the project a permit to run through the state.[143]

Finally, even if there is a way to store the separated CO_2 (either onsite or by pipeline to a suitable site), implementing CCS on existing EGUs may be impractical because of space constraints at the plant. A carbon capture facility is large and cannot be built without a suitable amount of land to support its construction. Many existing EGUs do not have the land available at the plant to construct the carbon capture facility, particularly in urban areas.

b. Water constraints

The well-documented water intensity of CCS operations also prevents it from being considered the "best" system of emission reduction. EPA has acknowledged that "[a]ll CCS systems that are currently available require substantial amounts of water to operate," and that these water demands "limit the geographic availability of potential future EGU construction to areas of the country with sufficient water resources."[144] It is well known that adequate water to support CCS operations is not available throughout the country. Accordingly, the Agency's conclusion in the 2024 GHG Standards that it "considers the water use requirements to be manageable and does not expect this consideration to preclude coal-fired power plants generally from being able to install and operate CCS"[145] is unsupported, arbitrary, and capricious, and it is appropriate for EPA to reverse this position now.

The D.C. Circuit has previously found that "an efficient water intensive technology … might be 'best' in the East where water is plentiful, but environmentally disastrous in the waterscarce West."[146] Therefore, the court ruled that EPA could not select a water intensive

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[141] *See* NRG Energy, Inc., Petra Nova status update: Petra Nova Carbon Capture System (CCS) placed in reserve shutdown (Aug. 26, 2020) (noting that the plant "has been impacted by the effects of the worldwide economic downturn, including the demand for and the price of oil" and that "[g]iven the current status of oil markets, … [t]he carbon capture facility has been placed in reserve shutdown status to allow it to be brought back online when economic conditions improve"), https://www.nrg.com/about/newsroom/2020/petra-nova-status-update.html.

[142] Summit Carbon Solutions, Project Benefits, https://summitcarbonsolutions.com/project-benefits/.

[143] R. Cramer, Iowa Public Radio, South Dakota regulators deny Summit's CO2 pipeline permit (Apr. 23, 2025), https://www.iowapublicradio.org/environment/2025-04-23/south-dakota-summit-carbon-capture-pipeline-permit.

[144] 83 Fed. Reg. 65,424, 65,443 (Dec. 20, 2018); *see also generally id.* at 65,442-44.

[145] 89 Fed. Reg. at 39,886.

[146] *Sierra Club*, 657 F.2d at 330.

technology as the BSER under section 111 because it would have the effect of precluding construction of new sources in states that lack the resources necessary (here, water) to allow compliance with the standard at a reasonable cost.[147] Because water scarcity is a barrier to deploying CCS, EPA's selection of CCS as the BSER for new base load combustion turbines during Phase 2, for fossil fuel-fired steam generating units that undergo a large modification, and for existing coal-fired steam generating units violates the requirements of section 111.

c. Parasitic load

The operation of CCS carries a significant parasitic load. According to EPA's estimates presented in the 2024 GHG Standards, operating CCS equipment at a new 500 MW combined-cycle combustion turbine would de-rate the plant by 11 percent to a 444 MW plant.[148] For coal-fired steam generating units, the Agency estimated that CCS equipment would reduce the output at a 474 MW-net (501 MW-gross) coal-fired steam generating unit by 23 percent to a 425 MW-net.[149] For combined cycle combustion turbines, EPA recommended in the 2024 GHG Standards that the developer at that time recommended that developers simply build a larger combined-cycle plant to compensate for the parasitic load.[150] This recommendation to build a bigger plant, however, does not (and cannot) speak to the needs of *existing* coal-fired steam generating units. Instead, EPA simply asserted that this was not a problem worth addressing: EPA "considers the energy penalty to not be unreasonable and to be relatively minor compared to the benefits in GHG reduction of CCS."[151]

The parasitic load associated with CCS is not minor: it amounts to 25 to 30 percent.[152] The energy transition has already put considerable strain on the electric grid and the nation's generating resources. Installing CCS will exacerbate these concerns and put reliability in even greater risk. EPA should now recognize that parasitic load considerations warrant a finding that CCS is not the "best" system of emission reduction.

C. The 2024 GHG Standards' Determination that the BSER for Existing "Medium-Term" Coal-Fired Steam Generating Units Is Co-Firing with 40 Percent Natural Gas Does Not Comply with Section 111's Requirements, and EPA Properly Proposes to Repeal It (C-24, C-28, C-29, C-30).

As EPA notes in the Proposed Rule, the 2024 GHG Standards' determination that co-firing with 40 percent natural gas is the BSER for existing medium-term coal-fired steam generating units "constitutes generation shifting and is therefore beyond the EPA's authority to

[147] *Id.*

[148] 89 Fed. Reg. at 39,935-36.

[149] *Id.* at 39,883.

[150] *Id.* at 39,936.

[151] *Id.* at 39,883.

[152] D. Walsh, Analysis of EPA's Proposed Construction Timeframes for CCS Projects at 4 (Aug. 3, 2023) (Attachment 3 to APPA Comments on Proposed GHG Standards).

require under CAA section 111."[153] The 2024 GHG Standards' determination that co-firing with 40 percent natural gas is a BSER explicitly requires shifting energy generation from coal to natural gas, precisely what the U.S. Supreme Court said EPA cannot do.[154] The U.S. Supreme Court made clear in *West Virginia* that the Agency has no authority to require a plant to change fuel type by switching 40 percent of its generation from coal to gas.[155] It does not matter whether the facility co-fires natural gas at 40 percent or if it would be required to fire 100 percent natural gas to comply with the standard. Impermissible fuel switching occurs any time EPA would require a change from one fuel type to an entirely different fuel type, as the standard here requires. Indeed, for an existing plant, the transformation of the source is particularly stark: The 2024 GHG Standards require changes to the facility's boiler, including "possible modifications" to millions of dollars of equipment such as the "steam superheater, reheater, and economizer heating surfaces that transfer heat from the hot flue gas."[156] The work to make these modification possible would takes years of engineering work and studies.[157]

Even if this form of fuel switching were legally permissible, the emission limit based on 40 percent co-firing is not achievable because the majority of coal plants do not have access to natural gas. While there may be a sufficient natural gas supply in the United States, natural gas co-firing is not sufficiently and uniformly available across the fleet of existing coal-fired steam generating units. In 2017, approximately just one-third of coal-fired EGUs co-fired with *any* amount of natural gas.[158] That number has not changed appreciably since that time. Moreover, the number of plants that co-fire natural gas in significant amounts, as contemplated by the 2024 GHG Standards, is minuscule—just four percent.[159] The vast majority of EGUs with co-firing capability only use natural gas at very low levels, primarily for the boiler startup or for holding it in "warm standby."

In addition, the 40 percent co-firing BSER is not cost-effective because of the need to construct pipeline infrastructure. For those coal-fired EGUs that do not have access to natural gas, co-firing would be cost prohibitive because the cost of gaining access to a pipeline is very expensive. EPA explained in the 2024 GHG Standards that the average cost for a pipeline "within the contiguous U.S. is approximately $280,000 per inch-mile" in 2019 dollars.[160] The

[153] 90 Fed. Reg. at 25,774.

[154] *West Virginia*, 597 U.S. at 728-29.

[155] *See id.* at 728 n.3 (expressing "doubt" EPA could "requir[e] coal plants to become natural gas plants").

[156] GHG Mitigation Measures-Steam 9

[157] *Id.*; NRECA Analysis of Fuel Switching 8.

[158] 84 Fed. Reg. at 32,544.

[159] *Id*. ("very few—less than four percent of coal-fired units—co-fired with natural gas in an amount greater than five percent of the total annual heat input").

[160] 89 Fed. Reg. at 39,894.

average diameter for a natural gas transmission pipeline is 18.3 inches.[161] This means that the average cost of an average size pipeline in the United States is $5,124,000 per mile.

APPA member Missouri River Energy Services (MRES) is a co-owner of Laramie River Station (LRS), which is in Wheatland, Wyoming. LRS lacks the necessary natural gas pipeline infrastructure to co-fire on natural gas. Constructing the additional natural gas pipeline storage and distribution infrastructure in Wyoming would be a costly and time-consuming process. It would likely include a lengthy evaluation under the National Environmental Policy Act, given the significant amount of federal land in Wyoming and complex endangered species issues in the area surrounding LRS, such as the sage grouse.

Another example of the costs to implement the 40 percent co-firing mandate is highlighted in a declaration by APPA member Kansas City Board of Public Utilities (KCBPU), which owns and operates the Nearman Creek Power Station. The declaration was submitted in support of a motion to stay the 2024 GHG Standards that was filed in the D.C. Circuit. As KCBPU explains in the declaration, it evaluated the feasibility of co-firing the Nearman Creek Power Station with natural gas and retiring it by January 1, 2039, as the 2024 GHG Standards allow a medium-term coal-fired EGU to do. KCBPU estimates that the cost of a contract for 10-year firm capacity for natural gas is approximately $48.4 million to co-fire at 40 percent.[162] This cost is in addition to the estimated capital investment to convert the plant, which ranged from $30-$50 million.[163] These costs further illustrate that a requirement to co-fire 40 percent natural gas is not cost-effective, especially for medium to small-sized public power utilities.

D. EPA Properly Proposes Repealing the Requirements for Existing Natural Gas- and Oil-Fired Steam Generating Units (C-31).

For existing oil- or gas-fired steam generating units, EPA proposes that implementation of the emission guidelines for these units "would be an inefficient use of State resources" given that these units "comprise a relatively small part of the source category and would contribute few or no emission reductions."[164] The 2024 GHG Standards acknowledge that the fleet of natural gas- and oil-fired steam-generating units continues to age, and the plants may operate with degrading emission rates.[165] While the aging fleet may continue to operate due to market pressures, its annual operating capacity factors are likely to be reduced, resulting in reduced emissions. EPA has previously excluded small or insignificant source categories from

[161] GeoCorr Blog, *Pipeline Projects Vary by Diameter Across the United States* (Aug. 9, 2021), https://blog.geocorr.com/pipeline-projects-vary-by-diameter-across-the-united-states (noting the "reported projected average diameters for pipelines of different projects through 2035" including natural gas pipelines) (GeoCorr Blog).

[162] Declaration of William A, Johnson ¶ 25, Exhibit I to Petitioner's Motion for Stay Pending Judicial Review, *Electric Generators for a Sensible Transition v. EPA*, No. 24-1128 (consolidated with lead case No. 24-1120), ECF No. 2056364 (D.C. Cir. May 24, 2024).

[163] *Id.* ¶ 26.

[164] 90 Fed. Reg. at 25,768.

[165] 89 Fed. Reg. at 39,897.

regulations.[166] Excluding from regulation sources that have only de minimis emissions is consistent with efficient regulatory practice. EPA and states should focus their limited resources on major contributors to emissions. If these requirements are left in place, the development of state plans to implement them will require staff time, technical consultants, modeling, stakeholder engagement, and administrative and legal review. Given that states have limited resources, pursuing the development of state plans for oil and steam boilers would present an administrative burden.

In addition, as EPA notes, the BSER for these units is "consistent with what most sources are already doing (i.e., business as usual), there was no additional cost associated with them, and they resulted in a degree of emission limitation that would have resulted in few, if any, emission reductions for any of the units."[167] Given this set of facts, continuing to regulate these units would not be cost-effective. If regulating these units "would most likely have no significant benefit," as EPA finds,[168] that regulating them is not cost-effective. The costs of state plan development outweigh any benefits, which are most likely to be zero.[169]

E. The Major Questions Doctrine Also Supports EPA's Alternative Proposal.

In *West Virginia v. EPA*, the U.S. Supreme Court—in examining the Clean Power Plan, EPA's first attempt at regulating existing fossil fuel-fired EGUs under section 111(d)—held that "there are 'extraordinary cases' that call for a different approach" than deferring to an administrative agency like EPA.[170] These are cases "in which the 'history and the breadth of the authority that the agency has asserted,' and the 'economic and political significance' of that assertion, provide a 'reason to hesitate before concluding that Congress' meant to confer such authority."[171] Although the Court had applied this rationale in previous cases, it officially referred to this principle as the "major questions doctrine" for the first time in that case. As detailed below, APPA believes this same reasoning applies to render the 2024 GHG Standards to be beyond any direct mandate that EPA has received from Congress and provides additional support for the Agency's Alternative Proposal.

In the Clean Power Plan, EPA proposed an approach known as "generation shifting," which prioritized non-GHG emitting electricity generating sources such as wind and solar over low-GHG emitting natural gas-fired generation, and lastly, coal-fired generation (which has higher GHG emissions than gas-fired generation). The U.S. Supreme Court, in *West Virginia*, determined that the Clean Power Plan's approach violated the major questions doctrine for four reasons. First, the Court noted that the Clean Power Plan significantly deviated from all previous rules by EPA under section 111(d) and found that:

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[166] *See, e.g.*, 75 Fed. Reg. 31,514 (June 3, 2010) (EPA's Tailoring Rule, which excluded small sources of GHGs from regulation under the CAA's Title V and Prevention of Significant Deterioration permitting programs).

[167] 90 Fed. Reg. at 25,775.

[168] *Id.*

[169] *See Michigan v. EPA*, 576 U.S. at 752.

[170] *West Virginia*, 597 U.S. at 721 (quoting *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 159 (2000)).

[171] *Id.*

> Prior to 2015, EPA had always set Section 111 emissions limits based on the application of measures that would reduce pollution by causing the regulated source to operate more cleanly…. It had never devised a cap by looking to a "system" that would reduce pollution simply by "shifting" polluting activity from dirtier to cleaner sources.[172]

The U.S. Supreme Court found this departure from established practice to be "unprecedented," stating that EPA's authority "effected a 'fundamental revision of the statute, changing it from [one sort of] scheme of regulation' into an entirely different kind."[173] This new interpretation would allow EPA to "demand much greater reductions in emissions based on a very different kind of policy judgment that it would be 'best' if coal made up a much smaller share of national electricity generation. And on this view of EPA's authority, it could go further, perhaps forcing coal plants to 'shift' away virtually all of their generation—*i.e.*, to cease making power altogether."[174]

Second, EPA's dictation of the optimal mix of energy sources is not within the Agency's traditional area of expertise, and the Court emphasized "[t]here is little reason to think Congress assigned such decisions to the Agency," especially given that "EPA itself admitted … '[u]nderstand[ing] and project[ing] system-wide … trends in areas such as electricity transmission, distribution, and storage' requires 'technical and policy expertise *not* traditionally needed in EPA regulatory development.'"[175] The court found "little reason to think Congress assigned such decisions" that are outside EPA's expertise to the Agency, and "'[w]hen [an] agency has no comparative expertise' in making certain policy judgments, [the Court has] said, 'Congress presumably would not' task it with doing so."[176]

Third, the U.S. Supreme Court expressed its skepticism of EPA's "generation shifting" proposal "find[ing] it 'highly unlikely that Congress would leave' to 'agency discretion' the decision of how much coal-based generation there should be over the coming decades," especially "in the previously little-used backwater of Section 111(d)."[177] The types of "basic and consequential tradeoffs" that would be required in making such a decision "are ones that Congress would likely have intended for itself."[178]

Finally, the U.S. Supreme Court found it significant that Congress had "'considered and rejected' multiple times" proposals to amend the CAA to establish a cap-and-trade program such as that promulgated in the Clean Power Plan or "to enact similar measures, such as a carbon

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[172] *Id.* at 725 (internal quotation and citation omitted).

[173] *Id.* at 728 (quoting *MCI Telecomms. Corp. v. AT&T*, 512 U.S. 218, 231 (1994)).

[174] *Id.*

[175] *Id.* at 729 (quoting EPA, Fiscal Year 2016 Justification of Appropriation Estimates for the Committee on Appropriations 213 (2015)) (emphasis in original).

[176] *Id.* (quoting *Kisor v. Wilkie*, 139 S. Ct. 2400, 2417 (2019)).

[177] *Id.* at 729-30 (quoting *MCI*, 512 U.S. at 231)).

[178] *Id.* at 730.

tax."[179] For all these reasons, the Court concluded that the major questions doctrine was applicable. The Court held that section 111(d) does not contain the "'clear congressional authorization'" to regulate in the manner that EPA attempted to do under the Clean Power Plan.[180]

As outlined below, the 2024 GHG Standards failed to address the legal deficiencies identified by the U.S. Supreme Court in *West Virginia*. Consequently, the 2024 GHG Standards violate the major questions doctrine and are unlawful. Although the Clean Power Plan was more transparent regarding its generation shifting approach and its objective to reduce fossil fuel-fired electric generation,[181] the 2024 GHG Standards yield an identical outcome— a shifting away from fossil fuel-fired generation (and the conversion of coal-fired units into hybrid-gas-fired ones). This is ultimately a dictation of what EPA views as the optimal mix of energy sources in the United States, with the EPA effectively (and in violation of *West Virginia*) using the 2024 GHG Standards to federally mandate a de facto decarbonization renewable portfolio requirement on electric generation on a national level.

First, although EPA based the 2024 GHG Standards on emissions-reducing technologies and "measures that would reduce pollution by causing the regulated source to operate more cleanly,"[182] the reality is that, as discussed above in Section IV.B, 90 percent CCS technology is not yet adequately demonstrated, not achievable, and is not cost-effective, and as discussed above in Section IV.C, in addition to being overt generation shifting, co-firing with 40% natural gas is not achievable and is not cost-effective. The reliance in the 2024 GHG Standards on technologies that are currently not in widespread commercial use and on infrastructure that will take many years to build creates significant uncertainty for utilities in resource planning and development. Utilities must contend in the resource planning process with any impacts caused by compliance with the 2024 GHG Standards, including impacts on cost-effectiveness, quality of power, and reliability, and the injection of such assumptions and uncertainties hinders the ability of electric generators to engage in prudent planning.

Moreover, even if 90 percent CCS technology were to become adequately demonstrated, achievable, and cost-effective (which is not currently the case), the timetable in the 2024 GHG Standards for implementing these technologies and measures is impracticable at best. Consequently, owners and operators face limited options, being forced to either prematurely retire their units or drastically reduce their usage to comply with the standards.

Second, the 2024 GHG Standards continue to force EPA's view of the optimal mix of energy sources within the United States, a prerogative that the U.S. Supreme Court has determined is not within EPA's authority. The Agency continues to prioritize renewable and non-GHG emitting forms of electric generation over fossil fuel-fired generation. Consequently, the 2024 GHG Standards effectively result in EPA, once again as it did with the Clean Power Plan, dictating what it believes the optimal mix of electric generation should be in the United

[179] *Id.* at 731.

[180] *Id.* at 732 (quoting *Util. Air Regul. Grp. v. EPA*, 573 U.S. 302, 324 (2014)).

[181] *Id.* at 730-31.

[182] 90 Fed. Reg. at 39,827 (quoting *West Virginia*, 597 U.S. at 725).

States: minimal to no reliance on coal-fired generation, with gas-fired generation reserved only for peak demand and as a backup for renewable generation. This action directly violates the major questions doctrine.

An owner or operator that intends to keep a coal-fired unit operating beyond 2039 must begin complying with an emission limit based on CCS starting in 2032.[183] First, as explained in Section IV.B.2, CCS is neither adequately demonstrated nor achievable, and the timeframe for compliance is entirely unrealistic. In effect, this compels owners or operators of coal-fired units either to retire them before 2032, or commit to retire them before 2039 if the unit is fortunate enough to have access to enough natural gas to co-fire at the 40 percent level. These forced early retirements will also result in the retirements of EGUs that recently installed costly emission control equipment, resulting in stranded investments. To the extent the 2024 GHG Standards take away from the state and local commissions and boards the decision over when a unit should retire, this is also a violation of the major questions doctrine. And if EPA's response is that states would have the option invoking the provisions of the CAA that allow the consideration of remaining useful life and other factors (RULOF)[184] to avoid early retirement, that argument is a fallacy. EPA has placed restrictions on the use of RULOF that render that provision useless.[185]

The situation is similar for new gas-fired EGUs. The 2024 GHG Standards effectively limit the construction of units solely for "peaking" purposes to backup renewable generation. Construction of a base load unit that will operate above 40 percent of its capacity factor requires a unit to install CCS by 2032 (which, as discussed in Section IV.B.1, is something that has *never* been done at a combustion turbine to date).

Permanently ceasing operation of viable generation resources is not what Congress had in mind when it enacted section 111, and Congress has not passed any subsequent legislation suggesting or requiring such a drastic step. By essentially requiring the early retirement of existing coal-fired EGUs, the 2024 GHG Standards go beyond the generation shifting regulations of the Clean Power Plan that were rejected by the U.S. Supreme Court. Section 111 does not contain language that provides retirement of existing facilities as an option for a standard of performance, and before EPA can put in place a program that essentially mandates the retirements of coal-fired EGUs, Congress needs to have spoken clearly that this is what it intended for EPA to do, and Congress has not done so. Similarly, Congress needs to have spoken explicitly before EPA can be deemed to have authority under section 111 to authorize limits to operation (i.e., a capacity factor limitation) as the 2024 GHG Standards do for gas-fired combustion turbines, or by forcing substantial use of an alternate fuel (40 percent natural gas at a coal-fired unit) during a period of years preceding a mandated date for ceasing operation.

Third, it continues to be "'highly unlikely that Congress would leave' to 'agency discretion' the decision of how much coal-based generation there should be over the coming

[183] 40 C.F.R. § 60.5740b(a)(5)(i)(G)(2).

[184] CAA § 111(d)(1), 42 U.S.C. § 7411(d)(1) (requiring EPA to "permit the State in applying a standard of performance to any particular [existing] source under a plan submitted [under this provision] to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies").

[185] *See, e.g.*, 89 Fed. Reg. at 39,836 (discussing EPA's restrictions on RULOF).

decades," and the provision of the CAA on which EPA relies as the authority for the 2024 GHG Standards continues to be "the previously little-used backwater of Section 111(d)."[186]

Fourth, Congress continues to grapple with the issue of climate change and how to best address it cohesively and on a national scale. Consistently, Congress has rejected programs resembling the 2024 GHG Standards, which would significantly restrict fossil fuel-fired electric generation in the United States.[187] APPA supports regulatory certainty through the congressional enactment of a federal clean energy standard designed to reduce GHG emissions from the electric sector while protecting affordability, reliability, and flexibility, while also addressing the impacts of climate change-driven legislation and initiatives in other sectors. While Congress recently passed the IRA, this statute primarily focuses on subsidizing and promoting the development of nascent technologies such as CCS, which is mandated in the 2024 GHG Standards, and hydrogen co-firing.[188] Once the IRA funds have been deployed to this end and if these technologies are indeed proven to be adequately demonstrated, achievable, and cost-effective, then it would be appropriate for EPA to evaluate them as potential BSERs for fossil fuel-fired EGUs. However, this milestone has not been reached at present.

For all these reasons, the 2024 GHG Standards violate the major questions doctrine. EPA's Alternative Proposal, however, would remove from the Standards those requirements (CCS and natural gas co-firing) that run afoul of the doctrine. If the Agency were to finalize the Alternative Proposal and include the minor modifications APPA suggests in Section V to the NSPS for intermediate load and Phase 1 base load combustion turbines, the remaining portions of the 2024 GHG Standards would be based on a system of emission reduction that is adequately demonstrated, achievable, and cost-effective. And regarding the repealed emission guidelines for existing coal-fired steam generating units in Subpart UUUUb, section 111(d) does not contain a deadline for EPA to establish emission guidelines for existing EGUs, which provides EPA with the opportunity to prudently wait until these technologies undergo further development before mandating their implementation.

V. EPA Needs to Reconsider the CO_2 Emission Standards for Combustion Turbines Operating at Base Load (Phase 1) and Intermediate Load for the Alternative Proposal (C-13, C-14).

In the Proposed Rule, EPA notes that it "is not reopening the BSER determinations or standards of performance and related requirements for new and reconstructed intermediate load and low load fossil fuel-fired stationary combustion turbines or for phase 1 for new and

[186] *West Virginia*, 597 U.S. at 730.

[187] *See, e.g.*, American Clean Energy and Security Act, H.R. 2454, 111th Cong. (2009) (climate cap-and-trade bill that did not pass the Senate); Clean Energy Jobs & American Power Act, S.1733, 111th Cong. (2009) (rejected cap-and-trade legislation).

[188] *See, e.g.*, The White House, Building a Clean Energy Economy: A Guidebook to the Inflation Reduction Act's Investments in Clean Energy and Climate Action at 9 (Jan. 2023) (The IRA "is the most ambitious investment in clean energy in our nation's history. It includes more than 20 new or modified tax incentives and tens of billions of dollars in grant and loan programs to unleash new clean energy technology investment and deployment and supercharge our transition to a clean energy economy."), https://bidenwhitehouse.archives.gov/wp-content/uploads/2022/12/Inflation-Reduction-Act-Guidebook.pdf.

reconstructed base load fossil fuel-fired stationary combustion turbines."[189] EPA did say, however, that it would receive "comment[s] on these issues in general and may, if appropriate, engage in further rulemaking at a future date" if EPA decides to finalize the Alternative Proposal.[190] As discussed further below, there are serious problems with respect to the 2024 GHG Standards' emission limitations for combustion turbines in the base load subcategory (Phase 1) and the intermediate load subcategory. APPA respectfully urges EPA to reconsider these standards due to two key concerns: (1) EPA's BSER approach appears legally questionable and represents poor policy; and (2) the emission standards rely on unrepresentative data for both subcategories. The capacity-factor threshold dividing the subcategories also lacks justification.

A. EPA Should Establish a Single, Input-Based CO_2 Emission Standard for Combustion Turbines.

1. The BSER determination for intermediate load combustion turbines and base load combustion turbines during Phase 1 improperly includes operating and ambient conditions.

EPA has tried multiple times to set GHG emission standards for EGUs and keeps hitting roadblocks. The explanation for this is that when setting an NSPS, the Agency typically identifies a proven add-on control technology as the BSER and then sets the emission standard at a level achievable with that technology "under most adverse conditions which can reasonably be expected to recur."[191] As explained by the U.S. Court of Appeals for the District of Columbia Circuit, basic "common threads" exist for EPA to use in evaluating the BSER and then setting the emission standard based on that BSER.[192] The court noted that "[c]hief among these common threads is a concern that the Agency consider the representativeness for the industry as a whole of the tested plants on which it relies, at least where its central argument is that the standard *is* achievable because it *has* been achieved (at the tested plants)."[193] To ensure this standard of representativeness for the industry as a whole is met, EPA must (1) "identify[] and verify[] as relevant or irrelevant specific variable conditions that may contribute substantially to the amount of emissions, or otherwise affect the efficiency of the emissions control systems considered"; and (2) when EPA relies on tests results, it should select or use them "in a manner which provides some assurance of the achievability of the standard for the industry as a whole, given the range of variable factors found relevant to the standards' achievability."[194]

For the power industry, there are several standard add-on controls that are routinely selected as BSER: scrubbers to control SO_2 emissions; selective catalytic reduction (SCRs) to control NOx emissions; and electrostatic precipitators (ESP) to control particulate matter emissions. All these controls can, for the most part, be adjusted to meet the emission standards

[189] 90 Fed. Reg. at 25,769.

[190] *Id.*

[191] *Nat'l Lime Ass'n v. EPA*, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980).

[192] *Id.* at 432.

[193] *Id.* at 432-33 (emphasis in original).

[194] *Id.* at 433.

that were based on them. When EPA sets NSPS for these pollutants, it takes the following steps: (1) it identifies the BSER (the technology); (2) it identifies a unit where this technology works at a high level to reduce emissions; (3) it adjusts the high level of performance from that unit to account for "the range of variable factors found relevant to the standards' achievability," and (4) from those bases, it selects the emission standard. Basically, an NSPS requires any new unit to install BSER technology (or an equivalent) and use it to achieve the same level of effectiveness as the high-performing unit EPA identified. The underlying logic of an NSPS is that if one unit can achieve a relatively low emissions rate for a pollutant by using certain control technology, then any unit should also be able to achieve this rate (adjusted for reasonable adverse conditions).

The problem with CO_2, however, is that no adequately demonstrated add-on technology exists that can be installed onto a combustion turbine and ramped up or down to meet a CO_2 emissions standard. For example, if a 12-month rolling average efficiency-based standard is set for a unit based on that unit's past performance, even if it may not be able to meet that standard in the future, depending on how the unit is operated. For example, if the unit has more startup and shutdown cycles, load change cycles, or operates at a lower level than in the past, it will likely not meet the standard. And even if it is operated in a similar fashion, it may not be able to meet the standard under different ambient conditions, such as altitude or ambient temperature.

In the 2024 GHG Standards, EPA identified "lower emitting fuels" and "highly efficient generation" as the BSER for intermediate load units and base load units during Phase 1.[195] This would have been fine if the Agency then based the emission standards for those subcategories on an input-based limit (as is the case for low load units in the 2024 GHG Standards) and/or the heat rate (i.e., the inherent efficiency) of the combustion turbine.[196] But EPA did not do that. Instead, it set the emission standards for intermediate load and base load units as a 12-month rolling average emission rate that it expressed as lb CO_2/MWh. But the average CO_2 emission rate over any period depends not only on the inherent rate of the combustion turbine but also on several other operational and ambient conditions.

As APPA's expert consultants J. Edward Cichanowicz and Michael Hein explained:

> At any given point in time, … the thermal efficiency of the [combustion turbine] is affected by a multitude of factors, among them: (1) the operating level; (2) degradation between maintenance cycles; (3) altitude; (4) ambient temperature; and (5) design margin. Simple-cycle [combustion turbines] are also affected by

[195] 89 Fed. Reg. at 39,917 Table 3.

[196] Any combustion turbine has an inherent (or specification) heat rate by design under any specified conditions. Combustion turbine manufacturers generally specify the design or inherent heat rate of the turbine under International Organization for Standardization (ISO) conditions at full load.

> inlet/outlet losses, while combined-cycle [combustion turbines] are also affected by air inlet fouling and condenser conditions.[197]

Typically, when EPA sets NSPS, it accounts for variable factors like the ones identified above in the Cichanowicz & Hein Report. Had EPA taken this approach in the 2024 GHG Standards, it would have based the NSPS on the performance of the best-performing units after making adjustments to account for the variable factors identified in the Cichanowicz & Hein Report including: (1) operating load and other operational factors, such as start-up and load change cycles; (2) degradation between maintenance cycles; (3) altitude; (4) ambient temperature; (5) design margin; (6) inlet/outlet losses for simple-cycle combustion turbines; and (7) air inlet fouling and condenser conditions for combined-cycle combustion turbines.

In the 2024 GHG Standards, however, EPA essentially incorporated all these variable factors into the BSER when it based the 12-month rolling average CO_2 emission standard for intermediate load combustion turbines and base load combustion turbines during Phase 1 on the performance of one or more existing units with relatively low measured CO_2 rates. In other words, instead of accounting for the range of these variable factors, which are clearly relevant to the achievability of the emission standard, EPA set the standard in a way that assumed that all of the intermediate load combustion turbines and base load combustion turbines in the country would operate in the same way and under the same conditions as the best-performing units. In essence, this means the 2024 GHG Standards mandate not only how inherently efficient the turbines must be (which would be within the bounds of the CAA), but *how* and under what conditions they may or may not operate.

This approach contravenes the CAA because, in specifying *how* a combustion turbine may or may not operate, EPA is essentially making energy production decisions that the U.S. Supreme Court has made clear are outside of EPA's authority under section 111.[198]

2. EPA should establish a single, input-based CO_2 emission standard for all combustion turbines.

Regardless of whether the approach EPA took in setting the 2024 GHG Standards for base load combustion turbines during Phase 1 and intermediate load combustion turbines was permissible, EPA should change its approach as a matter of policy. The current 2024 GHG Standards for intermediate load and base load (Phase 1) combustion turbines have significant energy and cost implications. Even if the Agency thinks it is permissible and reasonable to include variable factors that affect the CO_2 emission rate of a combustion turbine into the BSER, it certainly should not – and cannot – include in the BSER those factors that the operator of the turbine cannot control such as: (1) inevitable degradation – both in terms of degradation that cannot be repaired as the unit ages as well as a reasonable amount of degradation that will occur between maintenance cycles; (2) altitude; (3) ambient temperature; (4) a reasonable design or

[197] J.E. Cichanowicz and M. Hein, *Analysis of Combustion Turbine CO_2 Emission Rates Under the 2024 Greenhouse Gas (GHG) New Source Performance Standards (NSPS) for Fossil-Fired EGUs* at 4 (July 2025) (Cichanowicz & Hein Report). The Cichanowicz & Hein Report is included with these comments as Attachment 2.

[198] *See West Virginia*, 597 U.S. at 724-32 (discussing fact that EPA does not have authority to "substantially restructure the American energy market" or "dictat[e] the optimal mix of energy sources nationwide").

compliance margin; (5) inevitable inlet/outlet losses at simple-cycle turbines; and (6) inevitable air inlet fouling and condenser condition impacts at combined-cycle turbines.

But the most important factor that affects a combustion turbine's 12-month rolling average CO_2 emission rate is *how* the unit is operated. While it is true at a fundamental level that an operator can control the number of times the unit starts up and shuts down, the frequency and rate of load change, and the load level at which the combustion turbine operates, that does not mean that an NSPS should govern these decisions. A combustion turbine is operated in a manner that meets grid demands and maintains reliability and stability, all in accordance with economic dispatch principles. An NSPS that attempts to modify this approach has enormous energy and cost implications.

Thinking about these implications in a practical setting, an NSPS should not prevent a simple-cycle turbine from operating when it is needed to stabilize the grid or to avoid a blackout on a very hot or very cold day. But that is exactly what will happen if the operator determines that having another startup/shutdown cycle in the current 12-month period would result in an exceedance of the CO_2 emission standard. Similarly, an NSPS should not prevent a combined-cycle turbine from operating at minimum load (which has a higher CO_2 emission rate in lb CO_2/MWh) when the result will be that a more costly (and likely higher emitting) unit operates to replace the turbine's minimum load output. An NSPS that results in operators making decisions like this because they are concerned about exceeding the CO_2 emission standard threatens electric reliability and grid stability.

For these reasons, a BSER should not include variable factors that mandate how a unit operates—especially in the electric generation industry. As a policy matter, EPA should not impose a BSER and emission standard that essentially dictates how the unit runs. APPA agrees that the BSER for combustion turbines consists of "lower-emitting fuels" and "highly efficient generation" as the Agency determined in the 2024 GHG Standards.[199] The standards based on "lower-emitting fuels" should be established through an input-based standard as EPA did for low load combustion turbines, and the standards based on highly efficient generation should not be based solely on the inherent efficiency (heat rate) of the turbine. Under this approach, EPA could establish a given maximum heat rate that is permissible for simple-cycle and combined-cycle turbines. To protect against operators failing to maintain their turbines or allowing them to degrade, the Agency could establish a standard that allows no more than a given percentage of heat rate degradation at any time, which could be enforced through an initial heat rate compliance test and a recurring, annual heat rate test.

[199] *See* 89 Fed. Reg. at 39,917 Table 3.

B. EPA Should Reconsider the Phase 1 Standards for Combustion Turbines at Intermediate Load and Base Load if the Agency Retains Standards in the Form of lb CO_2/MWh.

1. The existing intermediate load standards are unachievable, even by highly efficient turbines.

Combustion turbines currently on the market are categorized by class, each with its own unique characteristics. Each turbine class serves particular purposes within the market and is designed and made to generate different levels of power to carry out those particularized functions. The most common combustion turbine classes include the following:

- **Aeroderivative units.** These units are small (generally less than 125 MW) and for the electric generating industry, they are most frequently in the range of 30-100 MW. The design is often likened to a jet engine.

- **E-Class "frame" turbines.** These turbines generally range from 90 to 150 MW.

- **F-Class frame turbines.** These turbines generally range from 200 to 320 MW.

- **H-Class and J-Class frame turbines.** These turbines are generally the largest combustion turbines in the market, and they generally are greater than 320 MW.

EPA's emission standards for combustion turbines do not consider the extraordinary variation among the different classes of turbines. The Agency instead designed a standard based on a single set of turbine characteristics: operation in simple-cycle mode at annual capacity factors exceeding 20% and up to 40%. This is a serious and consequential shortcoming because the standard is not achievable or practical for every class of turbine. Moreover, because the standard is based on a single set of operating parameters, it effectively locks combustion turbines into the type of operations and particular uses on which the standard was based, preventing the industry from adapting combustion turbine use and operation. These flaws, their ramifications, and how EPA should rectify the shortcomings of the standards are described further below.

a. The emission standard for simple-cycle turbines operating at intermediate load are based on a subset of units that are not representative of most units—including highly efficient combustion turbines—that are currently on the market.

For simple-cycle combustion turbines in the intermediate load subcategory, EPA based the standard on an inappropriately narrow set of units, almost all of which were small aeroderivative turbines. Based on this evaluation, EPA selected an emission standard of 1,170 lb CO_2/MWh (on a 12-month average rolling basis). A closer look at the underlying data, however, demonstrates that most of the units included in the Agency's dataset did not meet the standard it selected. Indeed, even a majority of turbines of the same design and make as those on which EPA based the standard likely could not meet it.

The performance of the units within EPA's dataset is set out in Figure 1 below, reproduced from the Cichanowicz & Hein Report.

Figure 1 – CO_2 Emissions Rate vs. Nameplate Capacity: 30 Simple Cycle Units Operating Between 20 and 40% Capacity Factor (Cichanowicz & Hein Report Figure 3-3)

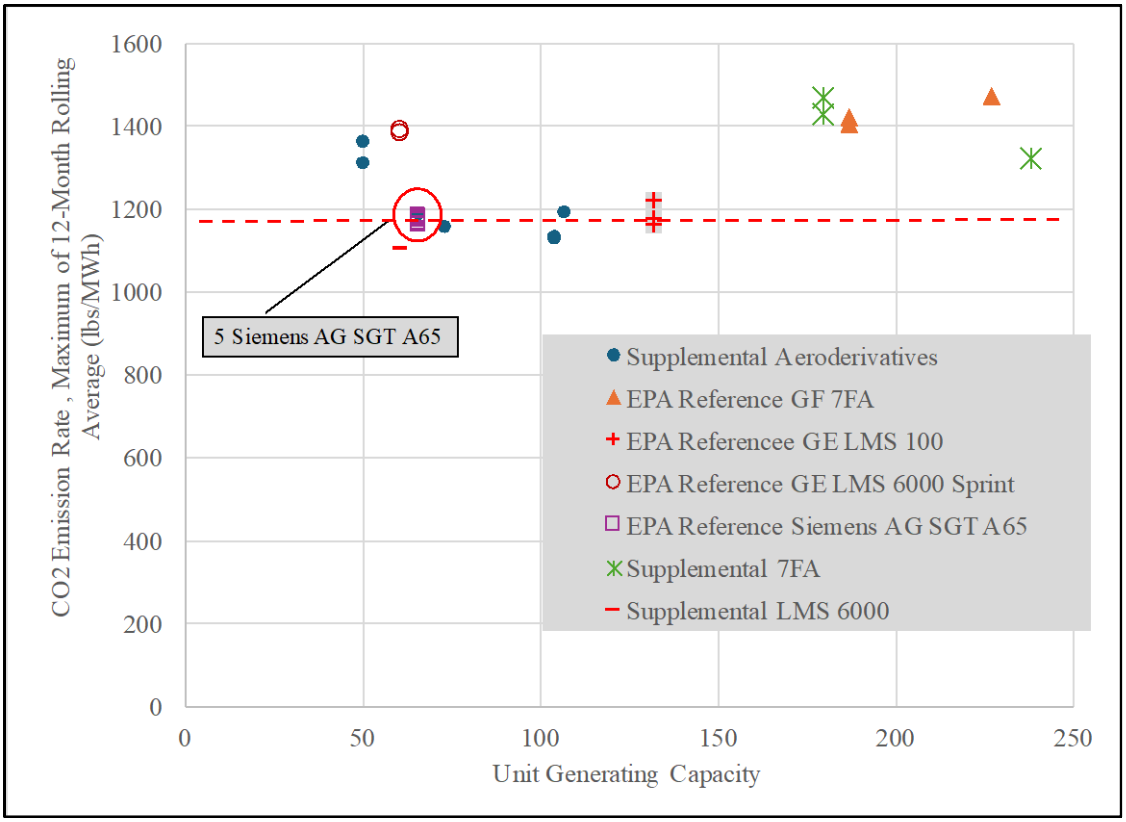


Figure 1 makes the following crucial demonstrations: First, even the limited number of units of the models EPA included in its dataset were not universally able to meet the emission rate limit that it chose as the standard. Second, a significant majority of the units in the dataset did not meet the Agency's chosen standard, including the majority of the aeroderivative units in the dataset. Third, all the frame units in the dataset, of which there were very few, emitted at rates well above the rate selected by EPA as the standard.[200]

Based on the foregoing considerations, EPA has not reasonably established that its standard is achievable by units within its own dataset, even less so by new units similar to those in the dataset. To evaluate this issue, the Agency would have needed to examine the reasons why only a minority of the aeroderivative units included in its dataset were able to meet the standard selected by EPA and why others did not meet that standard. The Agency would need to evaluate what actions new units similar to those included in the dataset would have to take to meet the standard. EPA would need to evaluate why the F-Class units in the dataset failed to meet the standard and what those units would have to do to meet it. Finally, EPA would need to evaluate whether the standard is achievable by unit types that were entirely excluded from the dataset, including E-Class, H-Class, and J-Class turbines. EPA did not undertake this analysis. Instead, as the Cichanowicz & Hein Report explains, the Agency selected a standard based on three

[200] Cichanowicz & Hein Report at 17.

aeroderivative models that are not representative of even the units within that class. EPA's analysis of that limited set of units cannot reasonably serve as the basis for a standard that applies to all turbine model types.

b. Even if operational constraints can serve as the basis for BSER, EPA should have established a significantly higher standard.

As noted above, EPA's current standard for simple-cycle combustion turbines operating at intermediate load is expressed in the form of a lb. CO_2/MWh emission rate limit. In effect, this is an efficiency standard because the CO_2 emitted is directly related to the amount of natural gas combusted over the averaging period (i.e., 12 months). To reasonably set a standard that uses efficiency as BSER, however, EPA must evaluate the factors that impact a unit's efficiency. The Agency's analysis did not take these necessary factors into account, and as a result, the emission standards are flawed and do not represent real-world conditions.

The Cichanowicz & Hein Report provides an assessment of the various factors that affect a unit's efficiency. It explains that the baseline is the efficiency of the turbine, which is determined by the design parameters inherent to the unit as determined at the point of its manufacture. Accordingly, turbine manufacturers can provide a guarantee of a unit's efficiency under ISO conditions, at full load. The reason efficiency guarantees are expressed with these limitations is that multiple additional factors that come into play in the real world will affect a unit's efficiency. These additional factors include: (1) the operating level; (2) degradation between maintenance cycles; (3) altitude; (4) ambient temperature; (5) inlet/outlet losses; and (6) design margin.[201] The Cichanowicz & Hein Report estimates the impact of these factors on efficiency to provide an approximate heat rate for operations under real-world circumstances. That analysis is summarized below in Table 1.

[201] *Id.* at 4. The CO_2 rate is also affected by the CO_2 content of the fuel. The Cichanowicz & Hein Report addressed with specificity only natural gas as a fuel, but the same concepts apply to combustion turbines fueled by other fuels, such as diesel oil.

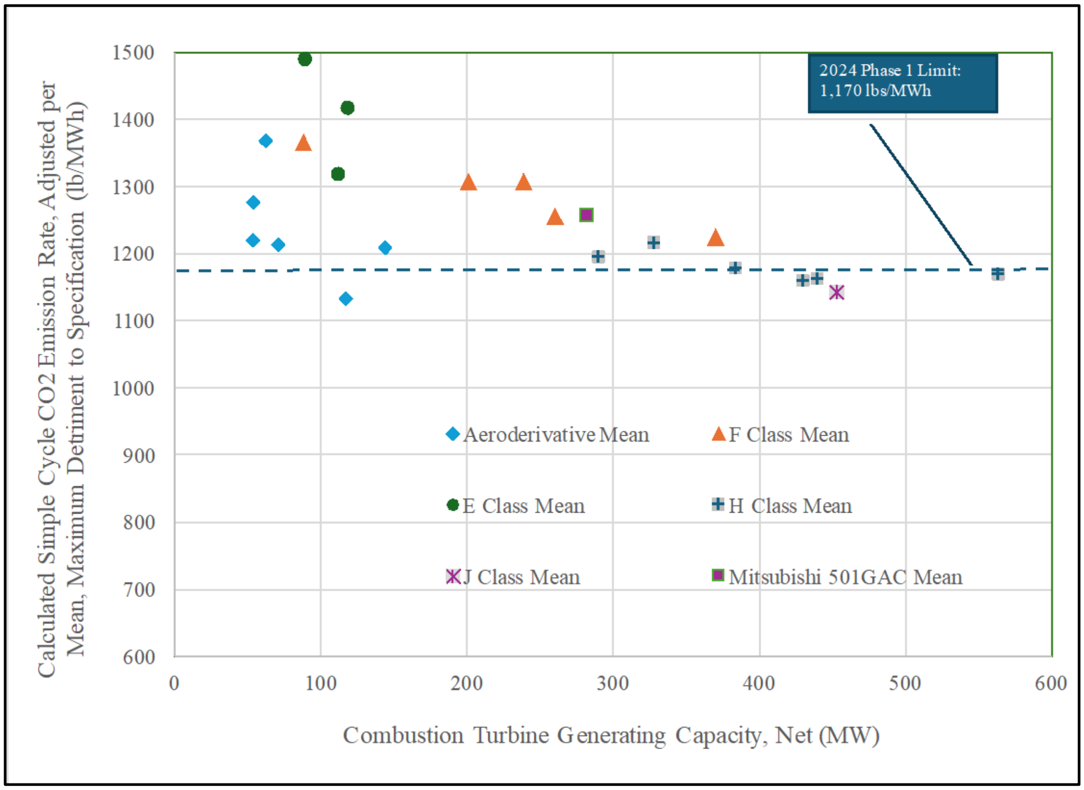
Table 1. Simple Cycle "Real World" Heat Rate Impacts (Cichanowicz & Hein Report, Table 2-1)

Factor	Heat Rate Impact	Mean Impact	Maximum Impact
Operating Load (fraction of capacity)	4% increase in heat rate at 80% load	3.5%	8%
Degradation	2-6% loss in 24,000 hrs; restorable to within 1-1.5% of design	4%	6%
Altitude[202]	3.5% loss in power = each 1,000 ft above sea level		
Ambient temperature	0.1% increase in heat rate = each 1 F above ISO	0.5%	1.6%
Inlet/Outlet losses per incurred air or gas pressure drop	0.2% increase in heat rate with each 1 inch w.g. increase in inlet/output pressure drop	0.8%	1.6%
CO_2 Compliance Margin	3-5%	4%	5%
Total		12.8%	22.2%

After assessing the potential impact of these factors, the Cichanowicz & Hein Report further estimates theoretical CO_2 emission rates for simple-cycle combustion turbines of the most common class types. Those estimates are presented in Figure 2.

[202] It is unknown if altitude affects heat rate, and as a result, the Cichanowicz & Hein Report assumes no impact from altitude apart from the documented loss of maximum power output altitude causes.

Figure 2. Calculated CO_2 Emission Rate: Simple Cycle (Cichanowicz & Hein Report Fig. 2-1)



As demonstrated in Figure 2; after considering average real-world impacts, most combustion turbines would be unable to meet EPA's 1,170 lb CO_2/MWh standard. The Cichanowicz & Hein Report and the figure above show that only a minority of aeroderivative models and the largest H-Class and J-Class units can meet the standard under these conditions. Based on the information in Figure 2, if EPA should issue a supplemental proposal to revise this standard, the analysis in the Cichanowicz & Hein Report should be used by the Agency to inform the development of a standard that is reflective of real-world operations.

Moreover, it is important to note that the impacts evaluated in the Cichanowicz & Hein Report and summarized here are *average* real-world impacts. More significant impacts and even greater deviations from EPA's standard will necessarily result in the real world, meaning that units would exceed the standard by even larger margins. An NSPS must be achievable and take into account actual likely operating conditions, which means the performance standards for base load and intermediate combustion turbines should accordingly be even higher than implied by this assessment of average impacts.

2. EPA's Existing Base Load Standards Are Unachievable by Many Highly-Efficient Turbines on the Market.

The Phase 1 emission standard for base load natural gas-fired, combined-cycle combustion turbines for units with base load ratings greater than 2,000 MMBtu/h is 800 lb CO_2/MWh. That standard increases on a sliding scale for smaller units to a maximum of 900 lb

CO_2/MWh for units with base loading ratings of 250 MMBtu/h. As is the case with the intermediate load standards for simple-cycle turbines, this standard is flawed because it cannot be achieved by the units to which it applies and because it was based on unrepresentative and inaccurate data.

a. The standard for combined-cycle combustion turbines operating at base load is based on unrepresentative data of a single unit's performance.

For Phase 1 base load units, EPA selected an emission standard of 800 lb. CO_2/MWh for units with a base load rating greater than 2,000 MMbtu/h. The Agency based this standard on the emission rate achieved by a single unit at the Dresden power plant in Ohio. It made this choice even though the dataset EPA evaluated included 59 units, the vast majority of which did not meet such an emission rate. The reasons why the Agency made this selection are, at best, unclear.[203] Additional analysis provided in the Cichanowicz & Hein Report demonstrates why this standard is unsupported and why it must be revised.

Figure 3, reproduced from the Cichanowicz & Hein Report, shows the performance of the units in EPA's dataset along with ten additional units identified by APPA's expert consultants. As that figure demonstrates, the majority of the units evaluated did not meet the emission rate EPA selected for the standard. On the contrary, as shown in Figure 4, only a handful of units performed at a rate equal to or better than the Dresden plant.

[203] *See* Cichanowicz & Hein Report at 24-27.

Figure 3 – CO_2 Emissions Rate vs. Nameplate Capacity: Combined Cycle Units (Cichanowicz & Hein Report Figure 3-4)

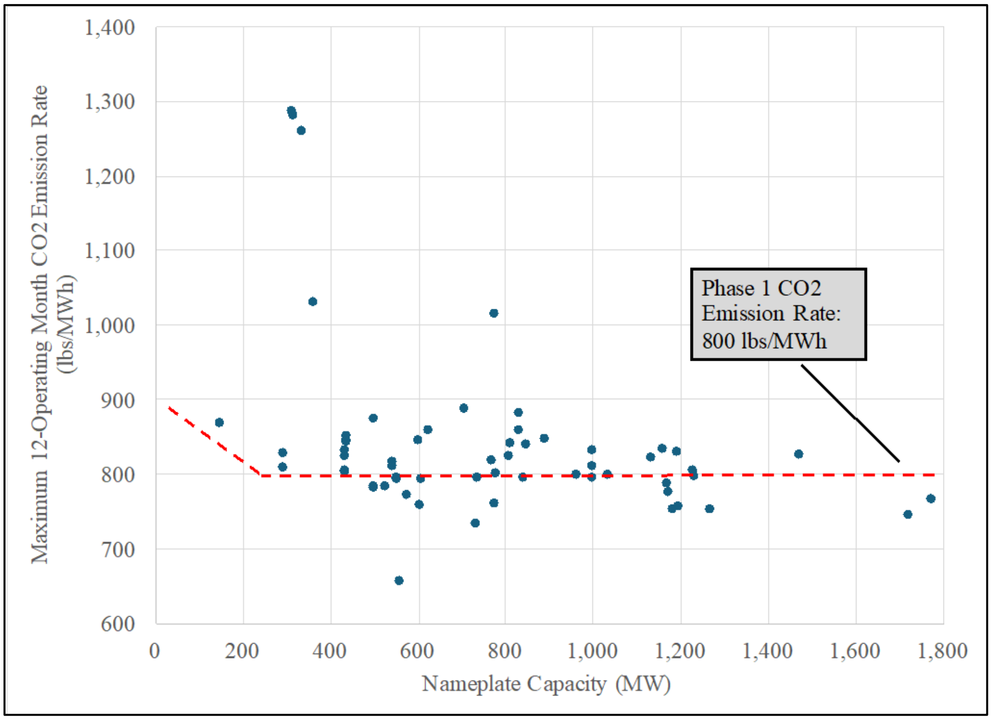
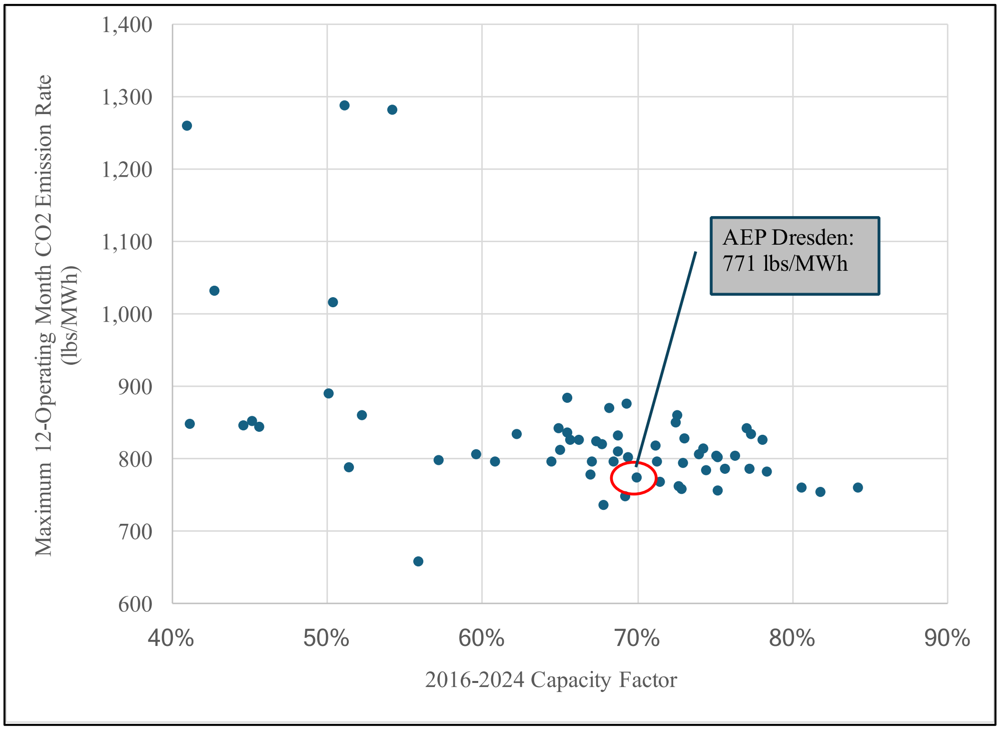


Figure 4 – CO_2 Emissions from the Combined Cycle Population: Role of Dresden (Cichanowicz & Hein Report Figure 4-4)



In setting this standard, EPA failed to evaluate crucial information. It did not consider the factors that caused the units emitting at higher rates than Dresden to do so; it did not consider what actions—if any—those units might be able to take to meet the standard EPA selected; and it did not evaluate the range of factors that impact the efficiency of units operating under real-world conditions, such as operation at various capacity factors, elevation, average temperature, etc. Indeed, the Agency did not even evaluate whether the Dresden unit, on which the standard is based, could achieve a limit of 800 lb CO_2/MWh if that unit had operated under different conditions. When setting an NSPS, EPA is obligated to consider "most adverse conditions that are expected to recur" and ensure that the standard can be achieved under those conditions.[204] It failed in that regard in the 2024 GHG Standards.

EPA's analysis underlying the current standard for combined-cycle combustion turbines fails for the same reasons its analysis supporting simple-cycle combustion turbines is inadequate. The other units may have higher emissions rates because they are different model combustion turbines with a slightly less efficient (although still highly efficient) design than the Dresden plant. Or the other units may have operated under different conditions. Regardless, failing to account for these factors when setting a standard is inconsistent with the law because the Agency must set an emission standard that is "capable of being met under most adverse conditions which can reasonably be expected to recur."[205]

[204] *Nat'l Lime Ass'n*, 627 F.2d at 431 n.46, 433.

[205] *Id.* at 431 n.46.

b. Even if EPA can base BSER on operational constraints, the best available information shows that the current standard for combined-cycle units operating at base load is too low.

As explained above with respect to the standard for simple-cycle units, because the existing Phase 1 standard for combined-cycle combustion turbines is an emission rate limit expressed in terms of lb CO_2/MWh, it is in essence an efficiency standard. That is because there is a direct relationship between the amount of CO_2 emitted and the amount of natural gas combusted to power the unit.

To provide a reasonable basis for an efficiency standard, it necessarily follows that EPA must evaluate the various factors that impact a unit's efficiency. As explained in the Cichanowicz & Hein Report, the efficiency of a combined-cycle combustion turbine is determined first by the design and parameters of the turbine itself, including its configuration. This inherent level of efficiency is typically expressed in a manufacturer's guarantee, usually expressed in terms of heat rate for electric generating units. The manufacturer's guarantee is generally given for a specific turbine model operating under ISO conditions at full load.

Actual efficiency, however, will vary due to the influence of numerous additional factors. The Cichanowicz & Hein Report identifies these factors as including: (1) the operating level; (2) degradation between maintenance cycles; (3) altitude; (4) ambient temperature; (5) air inlet fouling; (6) condenser conditions; and (7) design margin.[206] The Cichanowicz & Hein Report also estimates the level of impact these various factors can have on a unit's efficiency under average conditions. It should also be noted that approximately 75 percent of combined cycle units utilize duct burners in the heat recovery steam generator (HRSG) to boost power output, which further impacts the efficiency of the unit by one to three percent.[207] The combined cycle heat rate impact analysis is reproduced in Table 2, below.

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[206] Cichanowicz & Hein Report at 4.

[207] B.K. Schimmoller, Power Engineering Factor This, *Combined Cycles: Exploding the Cookie Cutter Myth* (Aug. 1, 2000), https://www.power-eng.com/coal/combined-cycles-exploding-the-cookie-cutter-myth/.

Table 2. Combined Cycle "Real World" Heat Rate Impacts (Cichanowicz & Hein Report, Table 2-2)

Factor	Impact	Mean Impact	Maximum Impact
Operating Load (fraction of capacity)	4% increase in heat rate per cycling, frequent startup/shutdown.	4%	6%
Degradation	3-5% loss in 10-15 Years	4%	5%
Altitude	0.2% increase in heat rate = each 1,000 ft above sea level	0%	1.2%
Ambient temperature	0.5% higher heat rate = per 10 F above ISO	0.25%	0.8%
Air Inlet Fouling	1.2% increase in heat rate, not recoverable	1.2%	1.8%
Condenser (Heat Removal)	1% increase in heat rate per 0.5-inch Hg absolute pressure[208]	2% (per 1.0 in Hg	4% (per 2 in Hg
Design Margin	3-5%	4%	5%
Total		15.5%	23.8%

The Cichanowicz & Hein Report further applies these average factors to the performance of the unit types subject to the standard for combined-cycle combustion turbines. Figure 5 below plots the emission rates that would result if these factors were considered.

[208] Cichanowicz and Hein Report at 4. Table 1 describes "new and clean" as 1.2 in Hg absolute; means and maximum impact values assumed as 1 and 2 in Hg absolute, respectively.

Figure 5. Calculated CO_2 Emission Rate: Combined Cycle (Cichanowicz & Hein Report Fig. 2-2)

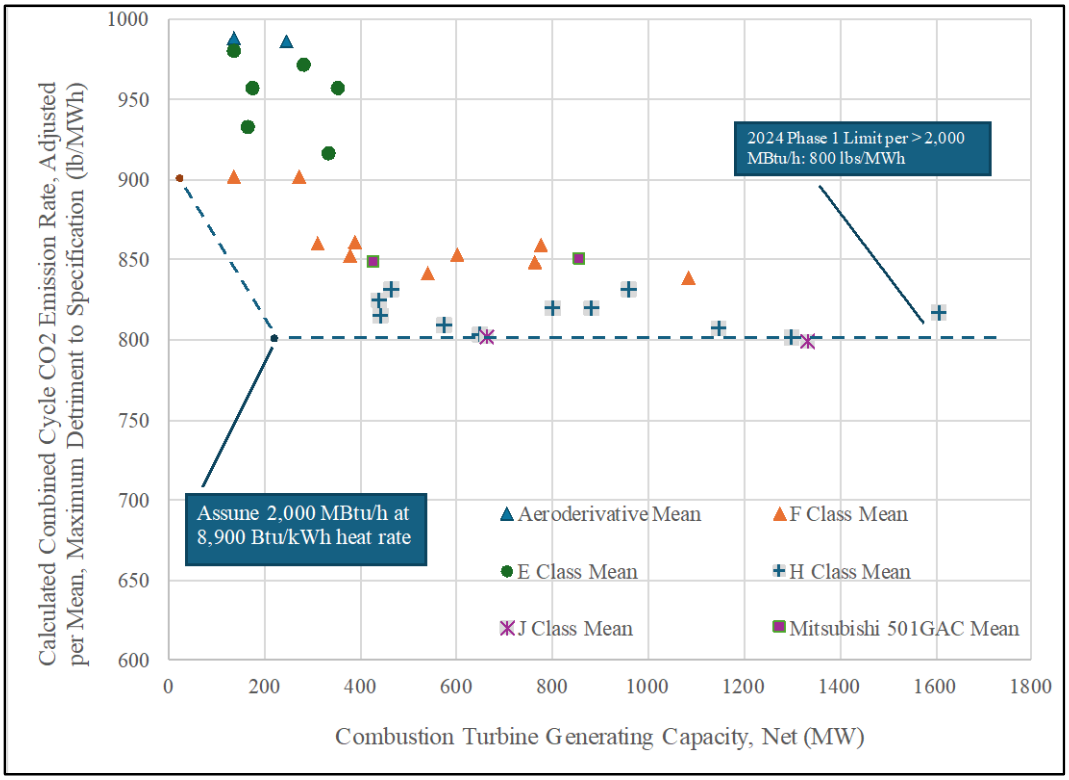


Figure 5 demonstrates that after adjusting for the average impacts of the factors affecting unit efficiency identified in the Cichanowicz & Hein Report, the majority of combined-cycle combustion turbines cannot meet the standard adopted by EPA. The Cichanowicz & Hein Report concludes that only a minority of H- and J-Class units would be able to meet the standard under these average conditions. Moreover, it is important to note that this analysis looks only at average operating conditions. Real-world operations will necessarily include even less favorable conditions, meaning that, as a practical matter, a significant number of units will be even further away from the possibility of compliance. As described above, in setting an NSPS, EPA must consider the least favorable conditions likely to recur. The Agency plainly did not do this in setting the current standard.

EPA should issue a supplemental proposal to revise the NSPS for non-low-load combined-cycle combustion turbines, and the proposed revisions should be based on the information presented in the Cichanowicz & Hein Report.

3. EPA Has Not Justified Its Threshold for Dividing Simple-Cycle and Combined Cycle Combustion Turbines.

a. Mode of operation—not utilization—should be the basis for subcategorizing units operating at more than a 12-month average capacity factor of 20%.

EPA's 2024 Rule created three subcategories of combustion turbines based on average annual capacity factor: (1) those that operate at capacity factors less than 20 percent, i.e., low load units; (2) those that operate at capacity factors of 20 percent to 40 percent, i.e., intermediate load units; and (3) those that operate above a 40 percent capacity factor, i.e., base load units. For the intermediate load and base load subcategories, the Agency based emission standards for these two subcategories on the performance of simple-cycle units for intermediate load and combined-cycle units for base load. EPA's approach effectively means that a simple-cycle unit cannot operate at more than a 40 percent capacity factor.

As explained further below, the Agency's rationale for imposing standards that limit operation of simple-cycle units is a levelized cost of electricity (LCOE) analysis in which EPA concluded that it is cost-effective to require all base load units to be combined-cycle units. EPA's LCOE analysis, however, does not address the cost of prohibiting the use of simple-cycle turbines at greater than 40 percent capacity factors in scenarios that are likely to occur in the real world. As an initial matter, EPA's authority to impose such a capacity factor limit is questionable at best. In effect, the standard amounts to a redefinition of the source by prohibiting simple-cycle units from operating under base load operating conditions. Even if this approach is permissible, it is, at the very least, bad policy.

Electric generators act rationally. Indeed, their entire operation model rests on the concept of economic dispatch, where units with a lower cost of producing electricity are called on before those with higher costs. If an electric generator proposes to construct a simple-cycle unit and run it at more than 40 percent of its capacity (for example 43%, or 47%, or even more), this means that the generator has determined it is more economically rational for it do this than construct a combined-cycled unit—likely because the LCOE for the proposed simple-cycle unit is lower than that for a combined-cycle unit.

Moreover, what EPA's LCOE-based analysis does not account for is the cost of prohibiting the use of a simple-cycle turbine at more than 40 percent under some circumstances. Take a simple-cycle combustion turbine that is constructed in 2025, on the expectation the unit would generally run slightly less than a 40 percent capacity, simple-cycle units that are generally intended to run at lower than 40 percent capacity factors may be called on to provide additional generating capacity during extreme weather—including unseasonably warm summers or cold winters—or when other generation is unavailable. If such units are unable to run at these times, the costs could be enormous, leading to blackouts and grid destabilization. EPA LCOE analysis does not take this into account.

The Agency could entirely avoid this problem and place its NSPS on firmer footing by refraining from setting standards that dictate the type of source that can be used for base load generation and instead subcategorizing combustion turbines based on their configuration rather than their capacity factors. Under this approach, simple-cycle units would meet the standard for simple-cycle units, and combined-cycle units would meet a combined-cycle NSPS regardless of capacity factor.

This approach not only avoids the problematic methodology EPA adopted in the 2024 GHG Standards but also provides unit owners with greater operational flexibility to respond to unpredictable economic and operational circumstances. This greater flexibility will enhance grid stability and reduce cost. Moreover, it is unlikely to result in an appreciable shift in the composition of the electric generating fleet. On the contrary, electric generators will continue to build the types of units that they believe are best suited to their needs based on their best projections. If, however, those projections are inaccurate, an approach that is based on the configuration of the unit, rather than the capacity factor, will allow for greater flexibility.

b. If EPA retains its current load-based subcategories, it should at least increase the demarcation line between intermediate load and base load.

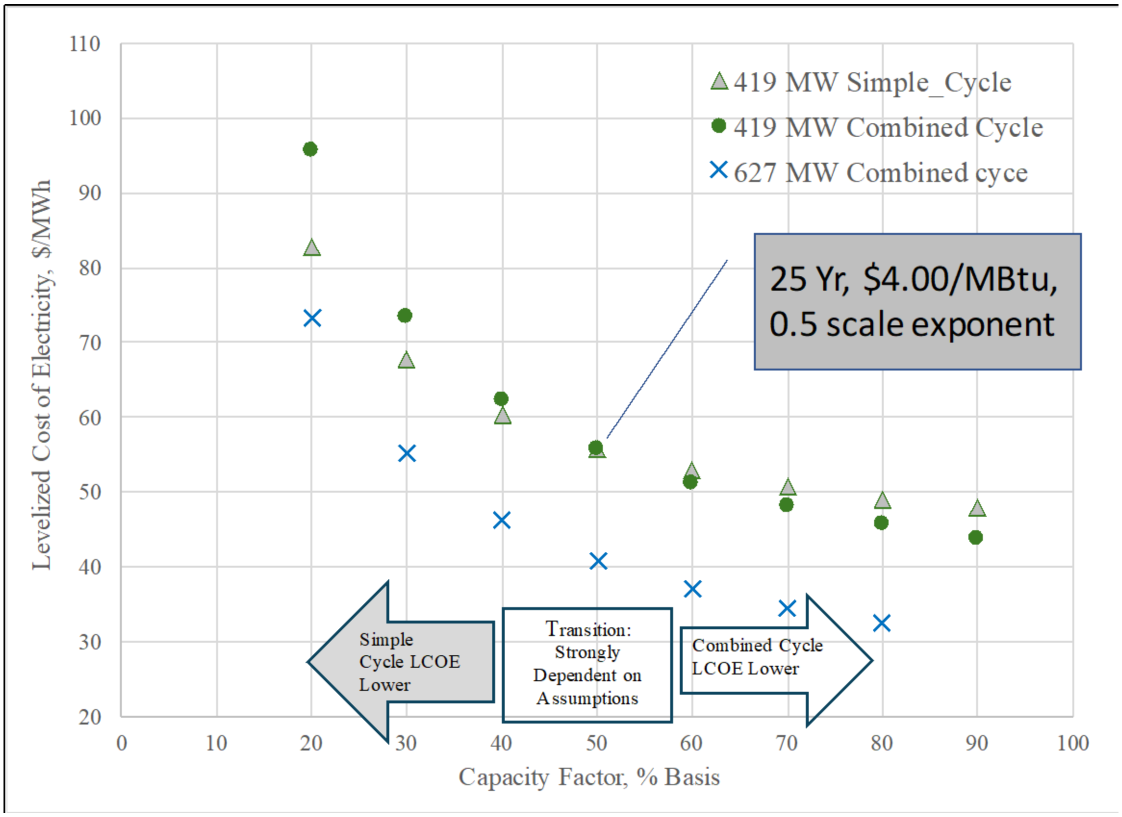
In the 2024 GHG Standards, EPA used a 40 percent capacity factor to distinguish between intermediate load units and base load units. That 40 percent value is derived from an analysis that uses multiple extrapolations, as explained in the Cichanowicz & Hein Report, which is not robust, includes substantial errors and uncertainty, and does not support the demarcation line EPA adopted.[209]

The Cichanowicz & Hein Report uses a simpler methodology that requires only a single extrapolation. This more robust approach identifies a 52 percent capacity factor as the appropriate demarcation line.[210] Figure 6, reproduced from the Cichanowicz & Hein Report provides a summary of those results.

[209] *Id.* at 28-31.

[210] *Id.* at 32.

Figure 6. LCOE Equivalent per Adjusted EIA Analysis (Cichanowicz & Hein Report Figure 5-1)



Based on this more robust and reliable analysis, EPA should issue a supplemental proposal and solicit comments on revising the base load capacity factor threshold.

The Cichanowicz & Hein Report methodology uses a number of different parameters than the Agency's analysis. The differences include the following:

Parameter	EPA Value	Cichanowicz & Hein Report Value
Facility Life	30 years	25 years
Future Cost of Gas	$4.42/MBtu	$4/MBtu
Scaling Exponent	0.6	0.5

The Cichanowicz & Hein Report provides a more substantial justification for each of the parameters it uses than EPA provided to support its analysis. For instance, the future cost of gas parameter used by the Cichanowicz & Hein Report is closer to the estimate provided by the Energy Information Administration than EPA's assumption. Likewise, the Cichanowicz & Hein

Report's scaling exponent is more appropriate.[211] Even if differences of opinion could support the parameters the Agency has chosen, it is inarguable that the Cichanowicz & Hein Report has used reasonable inputs for its analysis. The differences in outcomes, however, are significant. The conservative and reasonable course of action for EPA to take would be to adopt the better supported and less uncertain approach used in the Cichanowicz & Hein Report.

VI. The Proposed Rule's Primary Proposal

As previously noted, APPA believes the Alternative Proposal offers a more certain and durable option because it does not rely on new interpretations of the CAA. The 2024 GHG Standards currently present obstacles to the permitting and construction of much-needed new EGUs, and the Alternative Proposal, coupled with some adjustments to the Phase 1 NSPS for new base load and intermediate load EGUs, would provide the electric generating industry with the relief it needs. Nevertheless, APPA offers the following comments on the Primary Proposal for EPA's consideration, should it decide to finalize it, including perhaps after it finalizes the Alternative Proposal.

A. Before Listing a New Source Category Under Section 111, EPA Must Find that the Category Significantly Contributes to Endangering Air Pollution.

The Proposed Repeal Rule proposes to conclude that the Administrator must make a significant contribution finding before issuing GHG emission standards for a new source category, even if covered sources were previously listed under a different category.[212] This interpretation aligns with the CAA, which requires the Administrator to list a category of stationary sources if the Administrator concludes the category "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."[213] This finding, which is often referred to as an "endangerment finding," actually includes two separate findings by the Administrator: (1) a determination that emissions of the pollutant in question endanger public health and welfare; and (2) a finding that emissions of the pollutant in question from the source category cause or significantly contribute to that endangering air pollution.[214]

In 2015, EPA first addressed CO_2 emissions from new, modified, and reconstructed fossil-fuel fired EGUs under section 111(b). It claimed it did not need to make a new endangerment finding for fossil fuel-fired EGUs before issuing NSPS because it was not listing a new source category.[215] Rather, the Agency erroneously claimed it satisfied the endangerment finding requirement in 1971 and 1977 when it made such a finding for other pollutants from "steam generators,"[216] which are codified in EPA's NSPS regulations as Subpart Da, and

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[211] *See id.* at 33.

[212] 90 Fed. Reg. at 25,755.

[213] CAA § 111(b)(1)(A), 42 U.S.C. § 7411(b)(1)(A).

[214] 80 Fed. Reg. at 64,529.

[215] *Id.*

[216] 36 Fed. Reg. 5931 (Mar. 31, 1971) (one-sentence endangerment finding).

"stationary gas turbines,"[217] which are codified in EPA's NSPS regulations as Subpart KKKK. This position was challenged in the D.C. Circuit by 25 states, labor unions, and numerous industry parties, including APPA.[218] The case remains before the court, which is holding the case in abeyance.[219]

EPA erred when it said it was not listing a new source category. In fact, the 2015 rule established an entirely new category, codified in a new Subpart TTTT in EPA's regulations, which the Agency said it had "specifically created" to address GHG emissions from fossil fuel-fired EGUs.[220] Even if EPA could rely on two previous listings and combine them into one category without calling this "new," those findings involved only emissions of NOx, SO_2, and particulate matter, not GHGs. Section 111(b)(1)(A) requires EPA to make a finding that a source category significantly contributes to endangering air pollution for the pollutant being targeted before listing a new source category for that pollutant. While APPA is not suggesting that EPA could not or should not make such a finding, the fact of the matter is that it did not make that finding in 2015.

B. To Regulate a Pollutant from a Listed Source Category, EPA Must Find that Emissions of that Pollutant from the Listed Source Category Significantly Contribute to Endangering Air Pollution.

In the Proposed Rule, EPA "proposes to conclude that Congress required the EPA to identify more than a rational basis for regulating emissions from a source category."[221] APPA agrees. Starting in 2015 with the GHG NSPS for EGUs, the Agency interpreted section 111(b)(1)(B) as providing EPA with authority to "set a standard for an additional pollutant for a source category that was previously listed and regulated for other pollutants … as long as the EPA has a *rational basis* for setting a standard for the pollutant."[222] This previous interpretation has no foundation in section 111 of the CAA (which does not include the phrase "rational basis") and cannot be considered the "best reading" of that provision.[223] Indeed, numerous parties, including states, labor unions, and industry parties, have challenged the interpretation, including in the case involving EPA's 2015 promulgation of Subpart TTTT. These cases are currently in abeyance in the D.C. Circuit.[224]

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[217] 42 Fed. Reg. 53,657 (Oct. 3, 1977).

[218] *See* Opening Brief of Non-State Petitioners at 63-64, ECF No. 1659209, *North Dakota v. EPA*, No. 15-1381 (and consolidated cases) (D.C. Cir. Feb. 3, 2017); State Petitioners' Final Opening Brief at 34-35, ECF No. 1659341, *North Dakota v. EPA*, No. 15-1381 (and consolidated cases) (D.C. Cir. Feb. 3, 2017).

[219] Order, ECF No. 1688176, *North Dakota v. EPA*, No. 15-1381 (and consolidated cases) (D.C. Cir. Aug. 10, 2017).

[220] 80 Fed. Reg. at 64,512.

[221] 90 Fed. Reg. at 25,763.

[222] 81 Fed. Reg. 35,824, 35,842 (June 3, 2016) (emphasis added) (final rule promulgating NSPS to address methane emissions from the Oil and Natural Gas Production source category).

[223] *Loper Bright Enters. v. Raimondo*, 603 U.S. 369, 395-96 (2024).

[224] *See* State Petitioners' Final Opening Brief at 34-37, ECF No. 1659341, *North Dakota v. EPA*, No. 15-1381 (and consolidated cases) (D.C. Cir. Feb. 3, 2017) (challenge to Subpart TTTT); Opening Brief of Non-State Petitioners at

The endangerment and significant contribution findings for the NSPS addressing GHG emissions from fossil fuel-fired EGUs were made decades ago (in 1971 and 1977) for different pollutants (NOx, SO_2, and particulate matter) and different source categories (steam generators and stationary combustion turbines). To conclude that EPA could regulate *any* air pollutant based on decades-old and unrelated endangerment findings would provide the Agency with unfettered authority that Congress never intended it to have. Under this interpretation, EPA would have free rein to regulate any air pollutant from any source category with impunity.

In the 2015 NSPS rule promulgating Subpart TTTT, EPA conceded that other CAA provisions require endangerment findings for each pollutant regulated, but claimed section 111(b) leads to a different result.[225] This is contrary to the statutory text. Section 111(b)(1)(B) allows EPA to issue performance standards for sources listed under section 111(b)(1)(A).[226] Performance standards, by definition, are tied to a specific pollutant that the Agency EPA has found endangers health or welfare.[227] To find otherwise would give EPA authority to regulate pollutants even if they do not endanger health or welfare, which the U.S. Supreme Court said could not occur.[228]

The legislative history of the CAA confirms Congress viewed the various endangerment sections in CAA as "standardized" provisions and noted that "[t]his same basic formula is used" throughout the statute.[229] In fact, when EPA made its first endangerment finding in 2009 for motor vehicles, it noted that the CAA contains numerous endangerment provisions with "broad similarity in the phrasing of the endangerment and contribution decision."[230] The only difference correctly noted by EPA is that section 111(b) requires a higher level of "'*significant*'

63-66, ECF No. 1659209, *North Dakota v. EPA*, No. 15-1381 (D.C. Cir. Feb. 3, 2017) (challenge to Subpart TTTT); *see also, e.g.*, Nonbinding Statement of Issues of West Virginia, *et al.*, ECF No. 1634136, *North Dakota v. EPA*, No. 16-1242 (and consolidated cases) (D.C. Cir. Sept. 7, 2016) (raising the issue of whether: (i) EPA's NSPS to address methane emissions from the Oil and Natural Gas Production source category is unlawful because EPA failed to make endangerment and significant contribution findings with respect to methane emissions from the source category; and (ii) that NSPS is unlawful because EPA concluded it needed only a "rational basis" before regulating methane from the source category); Nonbinding Statement of Issues of the American Petroleum Institute at 2, ECF No. 1634081, *North Dakota v. EPA*, No. 16-1242 (and consolidated cases) (D.C. Cir. Sept. 6, 2016) (identifying as an issue whether EPA's methane NSPS for the oil and gas sector is unlawful because EPA asserted it did not need to make a pollution-specific endangerment and significant contribution finding for the Oil and Natural Gas Production Source Category).

[225] 80 Fed. Reg. at 64,530 (citing CAA §§ 202(a)(1), 211(c)(1), 231(a)(2)(A), 42 U.S.C. §§ 7521(a)(1), 7545(c)(1), 7571(a)(2)(A)).

[226] CAA § 111(b)(1)(B), 42 U.S.C. § 7411(b)(1)(B).

[227] *See id.* § 111(a)(1), 42 U.S.C. § 7411(a)(1) (defining a "standard of performance" as "a standard for emissions of air pollutants").

[228] *See Massachusetts v. EPA*, 549 U.S. 497, 532-33 (2007) (holding that EPA does not have "a roving license to ignore the statutory text"); *see generally id.* at 532-35.

[229] H.R. Rep. No. 95-294 at 50 (1977), *reprinted in* 4 COMM. PRINT, A LEGISLATIVE HISTORY OF THE CLEAN AIR ACT AMENDMENTS OF 1977 at 2517 (1978).

[230] 74 Fed. Reg. 66,496, 66,507 (Dec. 15, 2009).

contribution" than the other provisions.[231] This means that more – not less – evidence is required to make an endangerment under section 111(b).

At the end of the day, EPA realized the flaws of its interpretation, which is why it invented the "rational basis" test to try to put guardrails around its otherwise unlimited authority.[232] But this deferential standard is not what Congress intended, and the phrase "rational basis" is not anywhere in section 111.

In sum, section 111(b)(1)(A) requires EPA to find that emissions of an air pollutant from an already listed source category significantly contribute to endangering air pollution before issuing NSPS. APPA is not suggesting that EPA cannot or should not make this finding. But the CAA required such a finding to be made for CO_2 before the Agency issued performance standards to address emissions of CO_2 from fossil fuel-fired EGUs as the statute requires.

VII. Conclusion

Thank you for your consideration of these comments. APPA looks forward to working with EPA on this rulemaking. Should you have any questions regarding these comments, please contact Ms. Carolyn Slaughter (202-467-2900 or cslaughter@publicpower.org).

[231] *Id.* at 66,506 (emphasis added).

[232] 80 Fed. Reg. at 64,530.

Attachment 1

Analysis of Carbon Capture Utilization and Sequestration Technology
As BSER
Under the 2024 Greenhouse Gas (GHG) and New Source Performance Standards
for Fossil-Fired EGUs

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Midwest Ozone Group
Power Generators Air Coalition

August 4, 2025

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1 Introduction and Summary

On June 17, 2025, the Environmental Protection Agency (EPA or Agency) issued its proposed *Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units* rule.[1] The Proposed Rule, under its primary approach, seeks to repeal all greenhouse gas (GHG) emission standards for fossil-fueled power plants.

This report supplements technical comments submitted in the docket of the proposed 2023 GHG NSPS rulemaking.[2] Since the submission of the 2023 report, several references have become available, among these submissions by SaskPower regarding Boundary Dam Unit 4, additional capital cost from a completed Front End Engineering Design (FEED) study, and an update of CO_2 pipeline permits in several states.

This report addresses five topics. Section 2 describes how experience with carbon capture utilization and storage (CCUS) at industrial scale does not reflect utility duty, as most industrial applications deploy CCUS as a slipstream of the source rather than integrated for 24x7 duty over the load cycle. Section 2 discusses how slipstream duty provides flexibility to avoid or minimize complications due to load following – and highlights that utility applications at Petra Nova and – to a lesser extent – SaskPower Boundary Dam Unit 4 function as a slipstream.

Section 3 summarizes detailed studies of CCUS applications. Ten such FEED studies for coal-fired and nine for natural gas/combined cycle (NGCC) firing are identified, denoting those completed and results in the public domain. Although many FEED studies are in progress and their results have not been released, there are no definitive, funded CCUS demonstration projects underway.

Section 4 of the report explores the operating experience of SaskPower Boundary Dam Unit 4, which is re-evaluated, considering information submitted by the project operator that had not been previously disclosed. New information shows Boundary Dam Unit 4 CCUS enjoyed a flexibility in duty that would not qualify as a commercial demonstration in the context of the proposed GHG rule. Similarly, the Petra Nova experience is re-assessed in this manner.

Section 5 discusses the capital cost estimates of CCUS processes, updated to include one additional coal-fired unit not available in August 2023, and with costs for all studies presented in the same cost year (2022). These results show the capital cost for CCUS, as applied to either coal-fired or NGCC generation, require as much or more capital than necessary for a new, greenfield state-of-the-art coal-fired or NGCC generating asset without CCUS.

[1] 90 Fed. Reg. 25,752 (June 17, 2025) (Proposed Rule).
[2] E. Cichanowicz & M. Hein, Technical Comments on the Carbon Capture Utilization and Sequestration Aspects of the Proposed 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, August 7, 2023. Hereafter 2023 Technical Comments.

Section 6 presents an update of the permitting activities for CO_2 pipelines in the Midwest, summarizing the recent permit denials and project cancellation for Navigator Ventures, and permit denial for Wolf Carbon Solutions. In contrast, the Summit pipeline has secured permits in Iowa, North Dakota, and Minnesota, but continues to experience resistance and permit rejection in South Dakota. Summit has indicated its intent to continue to pursue access in South Dakota by altering pipeline routing to minimize barriers.

Cumulatively, these five topics, upon being revisited with recent information, further support the conclusion that CCUS for either coal-fired or NGCC application is not commercially demonstrated.

2 Discussion of Relevant Reference Cases

The 2024 Carbon Pollution Standard (CPS) designated CCUS as the best system of emission reduction (BSER) based on, among other factors, experience with industrial applications. There are two means in which CCUS currently applied on industrial sites fails to reflect utility operation –the process equipment is typically arranged differently and operates as a “slipstream” from the host unit, in contrast to an integrated operating mode.

Two EPA references cited in the 2023 proposed rule – Sears Valley Minerals and Bellingham Energy Center –deploy CCUS as a slipstream.[3]

- Sears Valley Minerals. The Sears site is comprised of three coal-fired units – two generating 27.5 MW and a third at 7.5 MW.[4] Public information suggests CO_2 capture is either intermittent or well below 90%, and the arrangement of three boilers suggests the CCUS process is configured as a “slipstream” that can be bypassed or deployed as needed.[5,6]

- Bellingham Energy Center. In the case of the 386 MW Bellingham facility, a DOE “fact sheet” reports CO_2 removal capability of 800 tons per day[7] as a slipstream.[8] The “fact sheet” suggests the unit operated from 1991 through 2005, with CO_2 removal of “85-95%”.[9] The Bellingham gas flow rate – not specified in the literature – by linked to a 40 MW gas turbine is approximately 280 lb/sec (e.g. GE LM6000), or 1/6th of the approximately 1,700 lb/sec processed by a state-of-the-art J- or H- Class Frame turbine.

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[3] 88 Fed. Reg. 33,240, 33,292 (May 23, 2023).
[4] Energy Information Agency 860 Data, File 3_1_Generator_Y2021. Operable tab, Rows 9148-9150.
[5] Elmoudir, W. et. al., HTC Solvent Reclaimer system at Searles Valley Minerals Facility in Trona, CA, Energy Procedia 63 (2): 6156-6165, December 2014.
[6] Specifically, if the CO_2 removal process treats flue gas from the smallest (7.5 MW) capacity unit, operation at 80% capacity factor will generate 2,375 tons of CO_2 per day – and daily CO_2 removal of 800 tons implies either a 33% removal for a complete 24-hour day, or 90% CO_2 removal for 35% operating time (perhaps one “daytime” shift).
[7] Elmoudir, W. et. al., HTC Solvent Reclaimer system at Searles Valley Minerals Facility in Trona, CA, Energy Procedia 63 (2): 6156-6165, December 2014.
[8] Specifically, if the CO_2 removal process treats flue gas from the smallest (7.5 MW) capacity unit, operation at 80% capacity factor will generate 2,375 tons of CO_2 per day – and daily CO_2 removal of 800 tons implies either a 33% removal for a complete 24-hour day, or 90% CO_2 removal for 35% operating time (perhaps one “daytime” shift).
[9] U.S. Department of Energy (DOE). Carbon Capture Opportunities for Natural Gas Fired Power Systems. Available at https://www.energy.gov/fecm/articles/carbon-capture-opportunities-natural-gas-fired-power-systems.

Operating CCUS or any environmental control process as a "slipstream" of gas, in contrast to being inseparably linked to the host unit, provides flexibility to manage uncertainties. A slipstream of gas flow can be operated independently of changes to the host unit. This feature enables the environmental control process to avoid issues with load ramping up or down, startup/shutdown, or process "upsets". The ability to maintain a constant gas flow rate isolates the process from these changes – process equipment can be taken off-line during startup/shutdown events, and activated only during well-controlled flow conditions.

Figure 2-1 is instructive on this topic. The figure presents a 3-dimensional model of the CCUS facility designed as a retrofit to Alabama Power NGCC generating units – either Daniel 4 or Barry Unit 6.[10] Figure 2-1 denotes flue gas processing equipment in green and power generation equipment – gas turbines, heat recovery steam generators, and cooling towers - in blue.

Each of the key CCUS process steps is defined in Figure 2-1. The components process flue gas according to a characteristic residence time and gas pressure drop, the latter monitored and input for flue gas fan operation. These process steps are the (a) exhaust gas recirculation (EGR) direct contact cooler, (b) CCS direct contact cooler, (c) CCS absorber, (d) CCS stripper, and (e) CCS and EGR cooling towers.

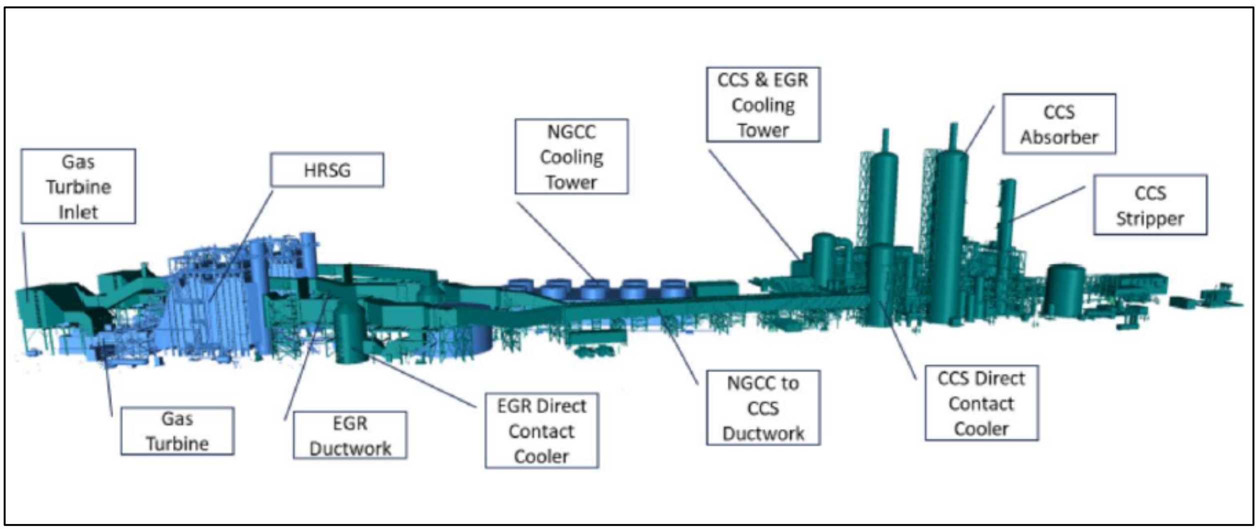

Figure 2-1. Arrangement of NGCC with CCUS Equipped with Exhaust Gas Recirculation

Further, the operation of each process step is determined by a series of subordinate actions, involving the consumption or production of liquid or gaseous media. Figure 2-2 presents a simplified process flow sheet of the carbon capture process for the arrangement in Figure 2-1.

[10] Retrofittable Advanced Combined Cycle Integration for Flexible Decarbonized Generation, presentation to the DOE Carbon Management Conference, August 6, 2024.

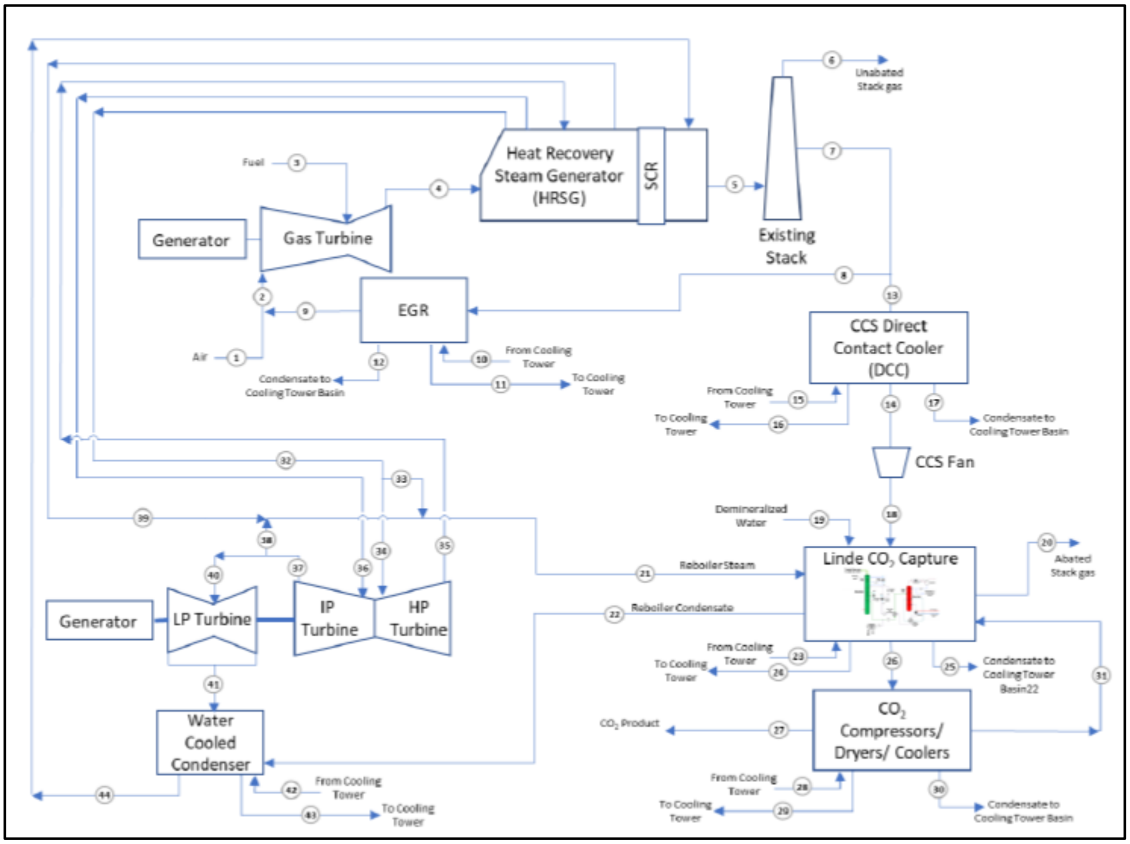

Figure 2-2. Simplified Process Flowsheet: CCUS Process Arrangement Daniel/Barry

As an example, the Linde CO_2 Capture step planned for potential application at Daniel 4 or Barry 6 is designed to process five input and four output flow streams. The five inputs streams are (a) flue gas for processing, (b) demineralized water, (c) reboiler steam for heating, (d) cooling tower effluent for cooling, and (e) partially processed amine streams containing CO_2. The four output steams are (f) condensate to the reboiler for heating, (g) process water to the cooling tower for cooling, (h) processed CO_2 for drying and compression, and (i) effluent flue gas for discharge. Each of these input and output streams operate in a dynamic manner, changing with host unit load, CO_2 concentration, and ambient temperature. Coordination of the steam supply and the flow rate of the liquid amine sorbent that removes CO_2 are key subordinate inputs important to process operation.

For CCUS units integrated 24 x 7 with a host boiler, process control systems must instruct these subordinate input and output flows to change with boiler operation. The characteristic time for some of the changes can be minutes or less.

Further, the mass rate of CO_2 production must be synchronized with the (not shown) steps for compression and delivery to the high-pressure pipeline.

The design challenge is ensuring process components—especially the CO_2 absorber and stripper—respond immediately to changing conditions rather than reacting to outdated data from 15-30 minutes earlier. Achieving such coordinated action is feasible– but rarely in a First-of-a-

Kind (FOAK) concept. Several iterations of the "nth" design will be required to be tested in authentic duty.

Conclusion: Experience with CCUS on an industrial process, or at utility demonstration with process duty on a flue gas "slipstream", does not represent the dynamic actions required for 24 x 7 duty on a host utility boiler. Slipstream success does not imply full-scale utility power plant success.

3 Status of FEED Studies

The proposed rule reports that several planned CCUS installations on coal-fired units have been abandoned[11] or faced challenge as to feasibility, after completion of FEED studies. Section 3 summarizes publicly available results from FEED studies and reports on project status.

The FEED study is a key CCUS decision metric. FEED studies (a) develop in more detail process flowsheets and/or equipment arrangement drawings, and (b) solicit budgetary quotations from suppliers to establish cost and availability. Some FEED studies include a construction plan, addressing the fabrication and delivery of the critical components to the site. EPA rightfully identifies these FEED studies as "…projects in the early stages of assessing the merits of retrofitting coal steam EGUs with CCS technology", with potential for "…the application of CCS to existing gas facilities".[12]

The follow-on to a FEED study and precursor to a demonstration is a detailed "Specification" study, which defines equipment attributes, layout, and an operating plan. These results are used to develop a request for proposal to solicit from a supplier a "firm" process design and cost. This "Specification" step has been completed only for SaskPower Boundary Dam 3 and Petra Nova.

3.1 Coal-Fired FEED Studies

Table 3-1 lists ten FEED studies addressing coal-fired generation. Table 3-1 describes the host unit features, the CO_2 capture technology evaluated, the targeted CO_2 removal, and the fate of CO_2 (e.g., either enhanced oil recovery or storage). FEED studies for the first six projects are publicly available; none of these projects will advance to follow-on studies. As noted by EPA in the proposal, the FEED study for Cleco's Project Vault was abandoned in late 2024, and a key participant in Minnkota Power's Project Tundra similarly withdrew from further participation.[13]

FEED studies for the remaining sites are in various stages of planning and execution, starting with Springfield City Water Light & Power (CWL&P) securing funding for a study at Dallman Unit 4.[14] The FEED studies for Duke Energy Edwardsport and Navajo Transitional Energy Company are in progress and are anticipated to be released in 2026. Cost results from the six publicly available reports summarizing these FEED studies are presented in Section 4.

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[11] 90 Fed. Reg. 25,772. (June 17 2025) (Proposed Rule).
[12] Steam EGU TSD. P. 23.
[13] 90 Fed. Reg. 25,772. (June 17 2025) (Proposed Rule).
[14] Brownstein, cc, Phase III Update: Large Pilot Testing of Linde-BASF Advanced Post-Combustion CO_2 Capture Technology at a Coal-Fired Power Plant, presented to FECM/NETL 2024 Carbon Management Research Project Meeting August 5, 2024.

Table 3-1. CCUS FEED Study Status: Coal-Fired Application

Station/ Unit	Capacity, MW [gross(g) or net (n)] (Layout, Aux Steam	Capture Technology:	CO_2 % Capture, MTs/h	CO_2 Fate
Milton R. Young/ Minnkota Power Co-op	1: 250 MW (n) 2: 470 MW (n) Note: "net" basis prior to CCUS	Econamine FG$^+$	90% target (11,000 MT/d)	Storage in saline reservoir, or EOR
Dry Fork/ Basin Electric	440(n) prior to CCUS	MTR Polaris membrane	70% target	"Carbon Valley" hub: Saline storage, EOR
NPPD: Gerald Gentleman	700 MW (2 x 350 MW) 642 MW w/CCUS	Ion Clean Energy solvent	90%, or 638K lbs/h (2.2 M MT/y)	EOR
Enchant Energy/San Juan 1-4	U1: 370 (n) U4: 507 (n)	MHI amine solvent	90%	Storage, with EOR to Permian Basin alternate
Prairie State Generating Company	816 (g) Aux power: 85.5 MW	MHI KM-CDR	95%, 8.46 MT /y	Off-site saline storage
SaskPower Shand	305(g) 279 (n)	KM CDR Process	90%	EOR at Weyburn, Midale
Cleco Power Madison Unit 3	605 MW(n) (CFB boiler, 70/30 pet coke/Illinois coal)	MHI amine solvent	95%	Storage in geologic formations
Duke Edwardsport	618 MW IGCC	Honeywell Advanced Solvent	95%	Storage on-site in geologic formations
Navajo Transitional Energy/Four Corners	1,500 MW Four Corners Station	MHI amine solvent	95% (10 million Mtons/y	EOR or Saline Storage
CWL&P Dallman U 4	200 MW	Linde/BASE Solvent	TBD	Storage in Illinois Basin

3.2 Combined Cycle

Table 3-2 lists nine FEED studies addressing NGCC generation. Similar to the case for coal, Table 3-2 describes the host unit features, the CO_2 capture technology evaluated, the targeted CO_2 removal, and the fate of CO_2 (e.g., either enhanced oil recovery or storage).

Table 3-2. CCUS FEED Study Status: NGCC Application

Station/ Unit	Capacity, MW [gross(g) or net (n)] (Layout, Aux Steam	Capture Technology:	CO_2 % Capture, MTs/h	CO_2 Fate
Golden Spread/ Mustang	480 (n), w/o CCUS 399 (n) w/CCUS (2 x 2 x 1) Steam: aux boiler	2nd gen solvent (piperazine)	90% 190 MT/h	EOR
Rayburn Energy	594(n) w/o CCUS 460 (n) w/ CCUS (2 x 2 x 1) Steam: turbine	Generic MEA conventional absorber/ stripper	85% 129 MT/h	Primary: saline fields. Secondary: local EOR.
Elk Hills	550(n) w/o CCUS 515 (n) w/CCUS 2 x 2 x 1 (w/duct-firing) Steam: aux boiler	Econamine FG Plus$^+$	90% of total effluent (74% CO_2 aggregate or 167 MT/h	Storage below the plant site
Daniel 4	529(n) w/o CCUS 450 (n) w/CCUS (2 x 2 x 1) Steam: turbine	Linde-BASF OASE® blue solvent	90%	Saline storage at Kemper County, MS
Barry 6	525(n) w/o CCUS 446 (n) w/CCUS (2 x 2 x 1) Steam: TBD	Linde-BASF OASE® blue solvent- EGR to elevate CO_2.	95+% MTs removal TBD	Same as Daniel 4
Calpine Deer Park (5 units)	5x180 CT + 1 Steam. (n) w/o CCUS (1,175 MW). CCUS aux power 75 MW.	Shell Cansolv (2nd Generation)	95% ~600 MT/h (6.5 MT/yr)	Storage at Gulf Coast sites
Calpine Delta Energy Center	857 MW (3 x 3 x 1) 3 Siemens W501F, 3 Deltak HRSGs, Toshiba Turbine	Ion Clean Energy Sorbent	95% or 2.4 MTa	Storage
TECO Polk Power Unit 2	1,168 MW (4x4x1) (Four GE 7FA turbines)	Ion Clean Energy Sorbent	95% or 3 MTa	TBD
LG&E Cane Run Unit 7	640 MW (n) Two Siemens SGT6-5000F turbines; 2 x 2 x 1	University of Kentucky water-lean solvent	95%	TBD

Of the nine FEED studies in Table 2, five have been completed with results available in the public domain. The status of these FEED studies is as follows:

- Completed, results in the public domain, no further actions planned. Golden Spread, Rayburn Energy, and Elk Hills –
- Completed, results in public domain, further actions pending. Daniel 4 and Barry 6.
- Results in progress, not yet available for release. Calpine Deer Park and Delta,[15] Tamp Polk Power, LG&E/KU Cane Run – the latter anticipating a completion date in 2025 and results publicly available in 2026.

In summary, of nine FEED studies on NGCC, four are completed with no further actions planned; two completed, but further actions are pending results in progress. Four studies are in progress, with results not available, and plans are dependent on the study outcome.

These activities show interest in deploying CCUS to NGCC, but as conceptual exercises. Notably, there are no operating CCUS applications or definitive, funded plans for commercial deployment.

Conclusion. Of the nineteen FEED studies either completed or in progress, none have led to an actual, funded CCUS demonstration projects. Several such studies are in progress and are anticipated to be completed in 2026. To date, none are committed to a demonstration.

[15] https://www.calpine.com/carbon-capture-and-sequestration-ccs/feed-studies/.

4 North American Utility Scale Process Experience

The EPA in the 2024 rulemaking proposed both SaskPower Boundary Dam Unit 3 and the NRG Petra Nova project provided sufficient experience to enable CCUS to be designated "adequately demonstrated at a capture rate of 90%."[16] Both demonstrations provide experience but are inadequate to establish CCUS as demonstrated and commercially available.

Section 4 presents the status of these projects updated with recently available or revised information.

4.1 SaskPower Boundary Dam 3

SaskPower has operated CCUS at Boundary Dam Unit 3 since 2014, employing an early generation Cansolv CO_2 process. Inherent to the Cansolv process is an SO_2 removal step to limit emissions to less than 10 parts per million (ppm) that, combined with improved particulate matter control, protects the amine sorbent from degradation.

Operating details of this unit are summarized in a previous report.[17] Several days preceding the close of the comment period for the 2023 proposed rule SaskPower shared additional details of the Unit 3 CCUS design and operation,[18] some of which not previously released to the public. In their August 2, 2023, filing SaskPower noted:

- Amine Sorbent Compromise. As cited in earlier publications,[19,20] the amine-based sorbent that captures CO_2 is compromised by contamination of fly ash from the particulate collector, reducing CO_2 capture effectiveness. SaskPower concedes this shortcoming and notes that eight years of development were required to improve operations to a state not yet fully disclosed.[21]

- Reduced Flue Gas Processing Rate. The demonstration facility operates below full gas flow capacity, except for a brief multi-day period after startup. This reveals an undisclosed design margin in the process.

[16] 89 Fed. Reg. 39,847 (May 9, 2024) (Final Rule).
[17] August 7, 2023 Technical Comments.
[18] SaskPower. Docket ID No. EPA–HQ–OAR–2023–0072: SaskPower Correction of Reference to Boundary Dam Unit 3 Emissions Performance in Proposed Rule. August 4, 2023. Document ID No. EPA-HQ-OAR-2023-0072-0687. Hereafter SaskPower 2023 Correction.
[19] Giannaris, S., *et al.* Proceedings of the 15th International Conference on Greenhouse Gas Control Technologies (March 15–18, 2021). *SaskPower's Boundary Dam Unit 3 Carbon Capture Facility—The Journey to Achieving Reliability.*
[20] Pradoo, P., *et al.* Proceedings of the 16th International Conference on Greenhouse Gas Control Technologies (October 2022). *Improving the Operating Availability of the Boundary Dam Unit 3 Carbon Capture Facility*
[21] SaskPower 2023 Correction.

- Slipstream Features. In a disclosure not previously shared or widely disseminated, Boundary Dam staff concede that a fraction of the flue gas from the Unit 3 boiler is not processed but bypassed – for purpose of reliability. The fraction of flue gas bypassed is 5% of total flow – or 58,325 actual cubic feet per minute (acfm) of the total 1,166,497 acfm.[22]

- CO_2 Optimized for 65-70% CO_2 Capture to Ensure a Higher Reliability. SaskPower does not describe what steps it takes to improve reliability at the expense of CO_2 capture. One likely means to do so is lowering the amine sorbent recirculation rate, which may be necessary depending on recirculation equipment reliability or a change in sorbent properties. This action can minimize reagent handling problems that could compromise reliable operation. A second means to compromise CO_2 removal to ensure high reliability is to reduce the volume of gas flow processed.

Each of these revelations - eight years after unit startup and numerous publications – document that additional work must be accomplished through numerous "Nth-of-a-kind" demonstration tests. The "takeaway" is that the Boundary Dam experience does not demonstrate CO_2 removal of 90%; rather that 65-70% CO_2 can be achieved with a caveat on reliability.

A graphic depiction of the reliability challenges addressed by SaskPower is the reported CCUS process availability, by quarter, since late 2022. These data – acquired from the SaskPower Boundary Dam blog – present the availability average per quarter, from Q2 2022 through 2Q 2025.[23] (Data from prior quarters is not reported in this manner and not available for comparison). Figure 4-1 shows the SaskPower target of 75% - their selection for their conditions – is typically met, but under the conditions that not all the flue gas is to be processed.

A CCUS process reliability of 90% is likely required to support a 90% CO_2 removal for the domestic U.S. coal-fired fleet. This GHG target – even under the conditions where all flue gas is not treated – is attained by Boundary Dam in 6 only of 13 quarters.

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[22] Giannaris, S. et. al., Implementing a second-generation CCS facility on a coal fired power station – results of a feasibility study to retrofit SaskPower's Shand power station with CCS, available at: https://ccsknowledge.com/pub/Publications/2020May_Implementing_2ndGenCCS_Feasibility_Study_Results_Retrofit_SaskPower_ShandPowerStation_CCS.pdf.. Hereafter Giannaris 2023.
[23] https://www.saskpower.com/about-us/our-company/blog/2025/bd3-status-update-q2-2025

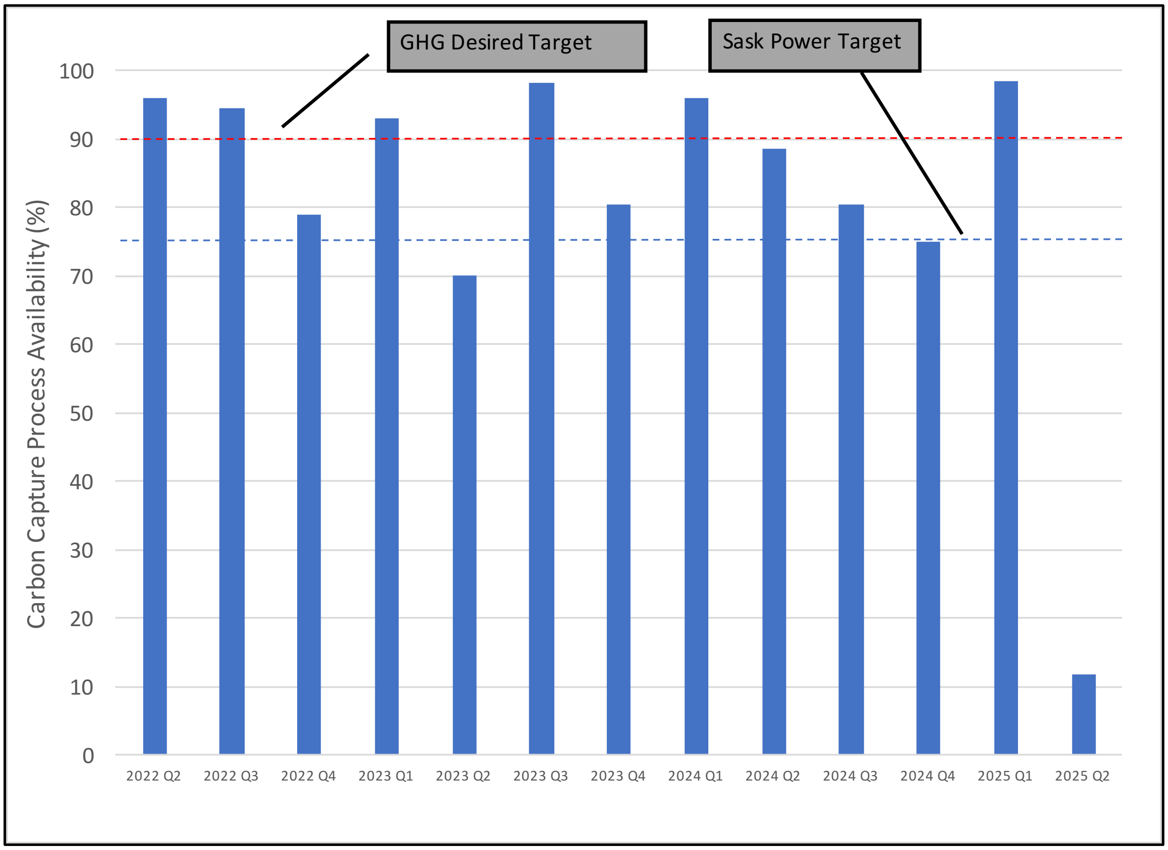

Figure 4-1. SaskPower Boundary Dam Unit 4 Carbon Capture Process Availability: 2002-2025

4.2 Petra Nova

NRG, owners of the W. A. Parish Generating Station, operated the Petra Nova CCUS process at Unit 3 from March 2017 through March 2020. The operating details of this unit are reported in previous technical comments.[24]

Petra Nova operates as a slipstream process, in that a constant flow rate of flue gas is extracted from the host unit, regardless of the duty cycle of the host boiler. Petra Nova thus enjoys the same flexibility and advantage of the industrial applications at Searles and Bellingham and (as recently disclosed) Boundary Dam Unit 4. Consequently, the reported 92% CO_2 removal over the three years does not reflect actual, full-scale duty if integrated into the host boiler duty cycle.

Further invalidating Petra Nova as representative of actual, full-scale utility duty is the retrofit of the combined cycle generating unit to explicitly provide, via the HRSG, a reliable steam source for reagent regeneration. This constant, unchanging source of steam ensures available heat to regenerate CO_2 from the sorbent – regardless of the host unit's operations. Thus, some of the

[24] August 7, 2023 Technical Comments.

challenges of maintaining high CO_2 removal during unit variability such as load changes are eliminated.

Two limitations in the report—unchanged since August 2023—hinder transparent cost evaluation and levelized cost estimates per tonne of CO_2 removal. First, the combined cycle generator retrofit to provide reliable steam affects CO_2 capture economics, but detailed process costs aren't presented in the final report, making CCUS capital and operating cost assessment difficult. Second, the allocation of construction and balance-of-plant costs between the combined cycle and CCUS budgets remains unclear, as does the accounting of value from the additional gas turbine power generated and its impact on CCUS operating costs.

Most significantly, as noted in the August 2023 Comments, the actual cost-per-tonne of CO_2 removal during process operation has not been disclosed.

In summary, the design and operation of the Petra Nova process –on the surface successful in achieving the 90% CO_2 reduction – does not support the proposition that such CO_2 capture can be reliably broadly achieved.

Conclusion. The Boundary Dam Unit 4 and the Petra Nova CCUS demonstrations, although contributing significantly to the CCUS knowledge bases, do not adequately demonstrate CCUS for utility application. Boundary Dam Unit 4, after eight years of optimization, is limited to a CO_2 reduction target of 65-70% to assure high reliability. Petra Nova reliability benefits from coincident retrofit of a NGCC process and HRSG to reliably supply process steam. These conditions are unsatisfactory for broad CCUS deployment to the domestic fleet.

5 Update of CCUS Cost Estimates

Section 5 updates cost estimates for CCUS, incorporating an additional FEED study released since the August 2023 Technical Comments. As noted in Section 3, there are only two verified capital costs for CCUS – SaskPower Boundary Dam Unit 3 and Petra Nova (the shortcomings of the Petra Nova cost are discussed in the previous section). All other costs are estimates.

Figures 5-1 and 5-2 present CCUS capital cost *per net generating capacity after CCUS* for coal-fired and NGCC applications, respectively. A total of 12 cases are presented – eight addressing coal-fired duty and four addressing NGCC application. The costs are all reported in 2022 dollars. The coal-fired costs include SaskPower Boundary Dam 3 and Petra Nova results, in addition to the six FEED studies. NGCC applications include only four sites for which results are publicly available. For both categories, the cost of a new generation technology – subcritical pulverized coal and NGCC with triple reheat HRSG – is presented for comparison.

5.1 Coal Fired

Figure 5-1 presents CCUS cost as reported for SaskPower Boundary Dam Unit 4,[25] SaskPower Shand,[26] Petra Nova,[27] Basin Electric Dry Fork,[28] Minnkota Milton R. Young,[29] Enchant Energy San Juan,[30] Nebraska Public Power District Gerald Gentleman,[31] and Prairie State.[32]

[25] Coryn, Bruce, *CCS Business Cases*, International CCS Knowledge Center, Aug 16, 2019, Pittsburgh, PA.
[26] Giannaris 2023.
[27] Final Scientific/Technical Report, *W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project,* DOE Award Number DE-FE0003311, Petra Nova Parish Holdings LLC, March 31, 2020, Report DOE-PNPH-03311. Hereafter Petra Nova 2020 Final Report.
[28] Commercial-Scale Front-End Engineering Design Study for MTR's Membrane CO_2 Capture Process, Final Technical Report, November 10, 2022. Hereafter 2022 MTR FEED Report.
[29] Project Tundra: Postcombustion Carbon Capture on the Milton R. Young Station in North Dakota, NRECA Update, October 2022.
[30] Crane, C., *Large-Scale Commercial Carbon Capture Retrofit of the San Juan Generating Station,* Overall Feed Package Report for DOE Cooperative Agreement DE-FE0031843, September 30, 2022.
[31] Carbon Capture Design and Costing: Phase 2 (C3DC2), Final Project Report, Final Scientific/Technical Report, DOE-FE0031840, March 2023.
[32] Full-Scale FEED Study for Retrofitting the Prairie State Generating Station with an 816-MWe Capture Plant Using Mitsubishi Heavy Industries America Post-Combustion CO_2 Capture Technology, August 2, 2022. Hereafter 2022 Prairie State FEED Report.

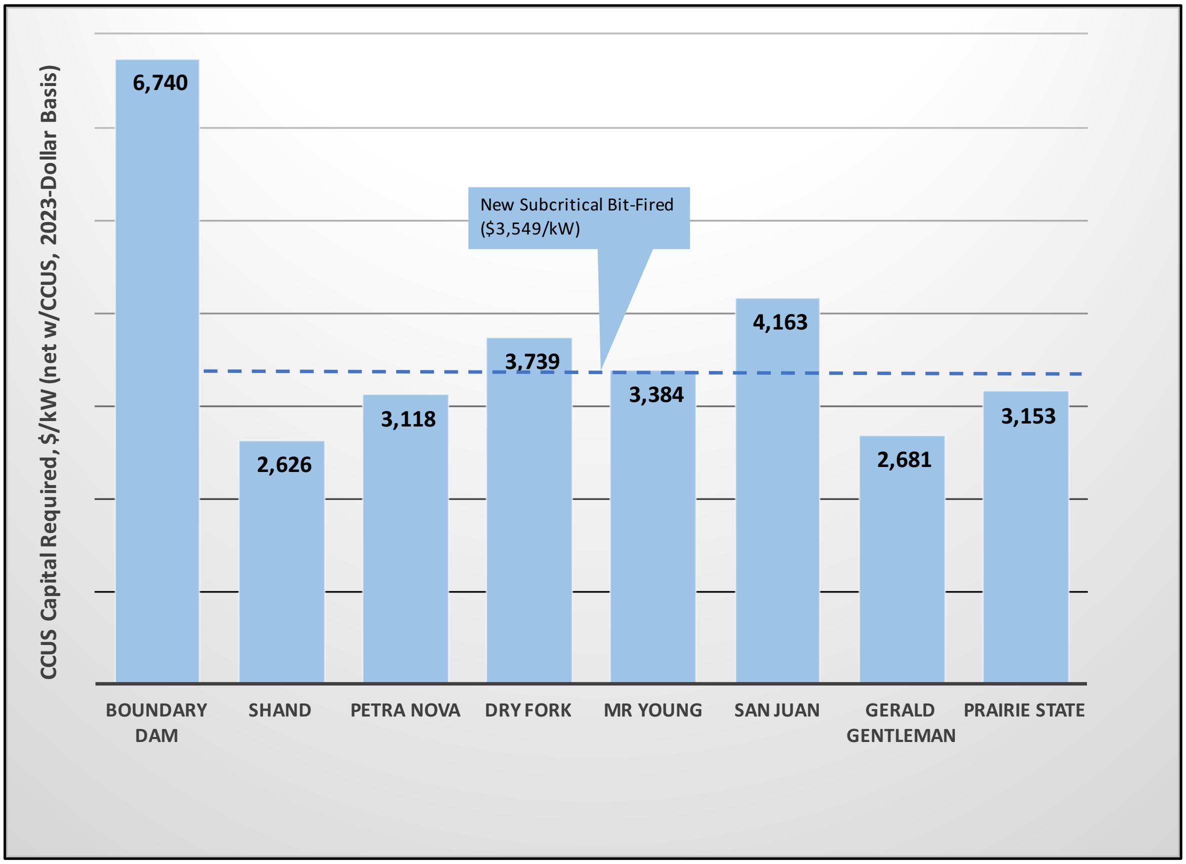

Figure 5-1. CCUS Capital Cost as Reported for Coal-Fired Demonstrations, FEED Studies

Figure 5-1 also reports capital cost for a hypothetical state-of-the-art subcritical coal-fired unit evaluated by the National Energy Technology Laboratory (NETL): 650 MW (net) with an 8,849 Btu/kWh net heat rate.[33]

Data in Figure 5-1 varies widely by site. Capital cost *per net generating capacity after CCUS* for four FEED studies is less than the cost for new coal-fired generation. In comparison, the CCUS cost for three FEED studies and Boundary Dam equals or exceeds that for new coal-fired generation. The Boundary Dam cost is atypical, given the "first-of-a-kind" status and relatively small generating capacity. An instructive cost metric to consider is the average of the FEED studies' cost results, excluding both Boundary Dam Unit 4 and the lowest of coal application (SaskPower Shand). These six cost estimates equate to $3,373/kW – almost identical to the cost of a new state-of-the-art subcritical coal-fired generator without CCUS.

It is important to recognize capital cost data in Figure 5-1 reflects only CO_2 capture, compression, and preparation for transport from the power station fence line. Capital and operating cost for CO_2 transport to the sequestration or EOR site, injection, and plume

[33] Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, DOE/NETL Report 2023-4320, October 14, 2022. Hereafter 2022 Bituminous/NGCC CCUS Retrofit.

monitoring are not included. Sites requiring minimal pipeline length will still incur significant cost for the sequestration step.

5.2 NGCC Applications

Figure 5-2 presents the capital cost estimated by FEED studies of NGCC applications reported in the public domain. These FEED studies address the Panda Sherman,[34] Golden Spread Mustang,[35] Daniel 4,[36] and Elk Hills[37] generating units.

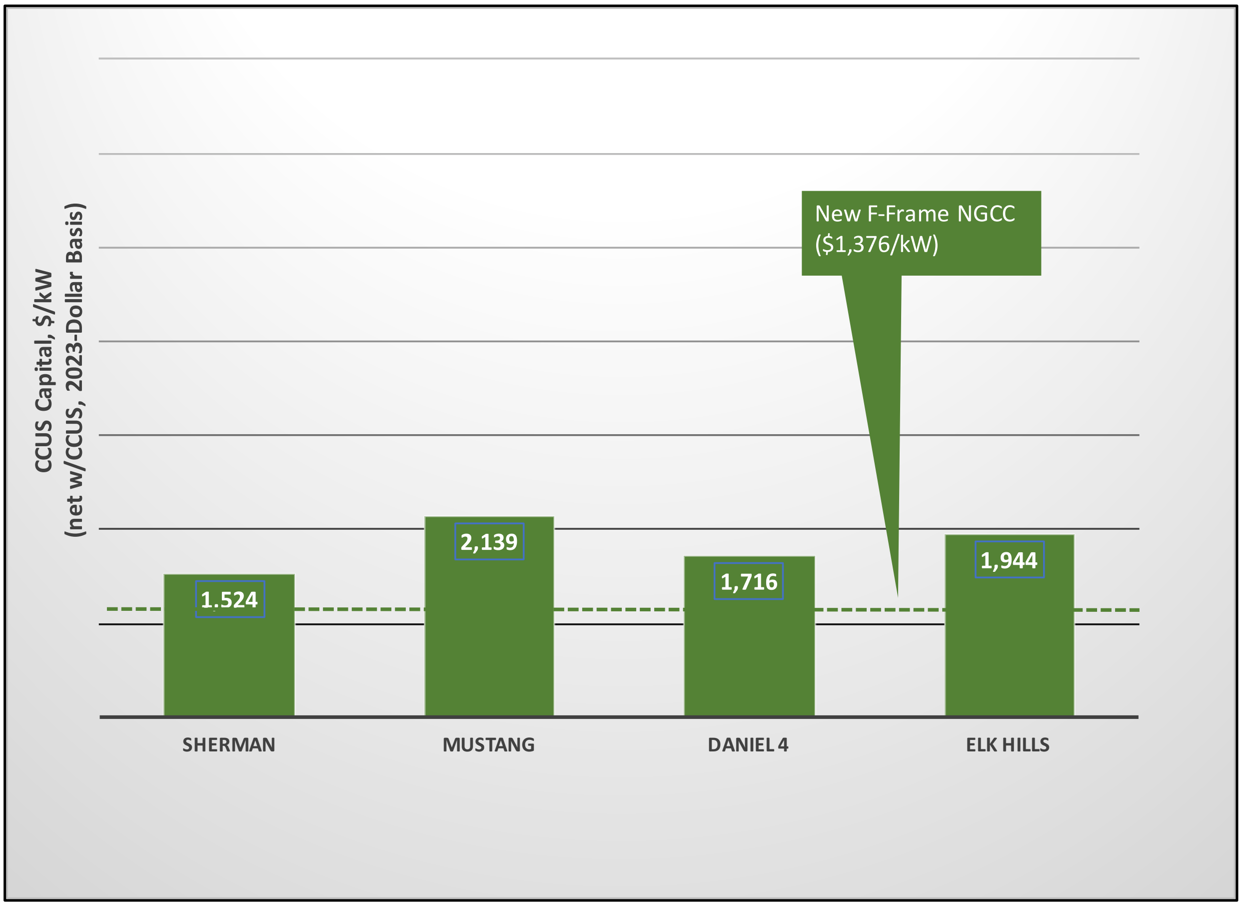

Figure 5-2. CCUS Capital Cost as Reported for NGCC FEED Studies

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[34] Panda Sherman 2022 Final Report.

[35] Rochelle, G., Piperazine Advanced Stripper (PZAS™) Front End Engineering Design (FEED) Study, DE-FE0031844, 2022 Carbon Management Research Project Review, August 17, 2022.

[36] Lunsford, L., et. al., Front End Engineering Design of Linde-BASF Advanced Post-Combustion CO_2 Capture Technology at a Southern Company Natural Gas-Fired Power Plant, Final Scientific/Technical Report, per DE FE0031847, September 30, 2022. Hereafter 2022 Daniel FEED Report.

[37] Front-End Engineering Design Study for Retrofit Post-Combustion Carbon Capture on a Natural Gas Combined Cycle Power Plant, Agreement DE-FE0031842, for US DOE/NETL, January 2022. Hereafter 2022 Elk Hills FEED Report.

Figure 5-2 also presents the capital cost for a hypothetical state-of-the-art NGCC generating unit without CCUS, as evaluated by NETL.[38] The NETL study estimates capital cost for F-Class and H-Frame combustion turbine designations, with cost for a "2 x 1" F-Frame design capable of 727 MW (net) and 6,363 Btu/kWh heat rate shown in Figure 5-2 as $1,376/kW.

Capital costs in Figure 5-2 vary widely by site, driven by, among other factors, the steam source for CCUS. For example, CCUS capital projected for Panda Sherman ($1,524/$/kW $_{\text{(net, with CCUS)}}$ is the lowest, with a key contributing factor being the use of the existing HRSG to provide steam for CCUS duty – but at the cost of a generating capacity penalty. Conversely, the highest capital cost (~$2,000/$/kW $_{\text{(net, with CCUS)}}$) is estimated for two units (Mustang, Daniel 4), with contributing factors being the need for auxiliary boilers to provide steam and preserving generating capacity.

The average of the four FEED studies – albeit representing different design concepts to provide CCUS steam –is $1,831/$/kW $_{\text{(net, with CCUS)}}$. This value represents a 30% premium to the cost developed by NETL for a 727 MW unit without CCUS.

Conclusion. The cost for CCUS applied to either coal-fired or NGCC generating assets approximates or exceeds that for stand-alone generation, without CCUS. For coal-fired assets, the cost for a new 650 MW subcritical unit and the average of the CCUS cost results (the latter as $/kW$_{\text{(net, with CCUS)}}$ from six FEED studies is almost identical, at $3,373/kW$_{\text{(net, with CCUS)}}$. For NGCC the cost of the CCUS process - based on an average of four FEED studies – at $1,831/kW$_{\text{(net, with CCUS)}}$ exceeds by 30% the cost of new 727 MW greenfield generation.

[38] Cost and Performance of Retrofitting NGCC Units for Carbon Capture – Revision 3, DOE/NETL-2023/3848, May 31, 2023. Hereafter 2023 NGCC CCUS Retrofit.

6 CO_2 Pipeline Permitting Issues

Broad CCUS deployment will require a significant increase in CO_2 pipeline capacity. Securing new pipelines requires design, permitting, and construction tasks – all within a time frame that will not delay the entire project. The August 2023 Technical comments presented details of the ongoing permitting conflicts and the delays incurred for certain projects. Section 6 provides a brief update on three notable projects.

The major actors in the pipeline permitting debates are summarized as follows:

- Navigator Ventures[39] proposed 900-mile Heartland Greenway CO_2 pipeline, bisecting Iowa from northwest to southeast and transporting CO_2 to Illinois. The approximate $3.2B project extends a total of 1,300 miles through South Dakota, Nebraska, Minnesota, and Iowa.

- Wolf Carbon[40] proposed 280 miles of pipeline to transport CO_2 from ADM ethanol-producing facilities in eastern Iowa to Decatur, IL, for terrestrial sequestration.

- Summit Carbon[41] plans 700 miles of pipeline in western and northern Iowa to transport CO_2 to North Dakota for existing EOR application. In Iowa alone, the proposed pipeline will cross 30 counties.[42]

Each of these organizations has pursued pipeline permits in several states: Iowa, Minnesota, North Dakota, Nebraska, and South Dakota. The permitting requirements vary significantly by state– Iowa presents perhaps the most structured steps, and Nebraska the least. Landowners cite numerous reasons for resisting access to their property. These include the role of eminent domain, safety due to CO_2 leaks, and concern that agricultural productivity is compromised within pipeline easements – meaning productivity is reduced 15% for corn and 25% for soy.[43]

The status of the pipeline permits as of July 2025 is described subsequently.

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[39] https://heartlandgreenway.com/about-us/.
[40] https://wolfcarbonsolutions.com/mt-simon-hub/.
[41] https://summitcarbonsolutions.com/project-footprint/.
[42] Proposed Iowa Pipeline Would Cross 30 Counties, Radio Iowa, Aug 20, 2021. https://www.radioiowa.com/2021/08/30/proposed-carbon-dioxide-pipeline-would-cross-30-iowa-counties/.
[43] Pipeline study shows soil compaction and crop yield impacts in construction right-of-way, Iowa state university College of Agricultural and Life sciences, November 11, 2021. Available at https://www.cals.iastate.edu/news/releases/pipeline-study-shows-soil-compaction-and-crop-yield-impacts-construction-right-way.

6.1 Navigator Ventures

Navigator Ventures, in October 2023, canceled the 1,300-mile pipeline project planned to cross five Midwestern states.[44] The company cited the challenging regulatory environment, particularly in South Dakota and Iowa. The permit was denied by South Dakota in September 2023[45] and Navigator requested Iowa to pause the permit application.[46] The permit was also withdrawn for consideration from Illinois.

Landowners and community groups organized against the Navigator project, focusing on concerns regarding eminent domain and the potential disruption to their ability to utilize their land. Significant opposition also was derived from concern about the potential for CO_2 leaks and other environmental impacts. Navigator has not clarified if and when these permits will be reconsidered.

6.2 Wolf Carbon

Wolf Carbon Solutions abandoned plans to construct the 95-mile segment of their pipeline across eastern Iowa, per a December 2024 filing with the Iowa Utilities Commission.[47] Wolf Carbon Solutions indicates the decision may not be permanent, with activities potentially restarted pending resolution of uncertainties.

The rational for abandoning the permits is the same as for Navigator - impact of eminent domain on private property rights and owners concern for public health. The concern for public safety was also highlighted as an issue by the Illinois Commerce Commission.

6.3 Summit Carbon

Summit as of July 2025 remains the only presently active developer of a CO_2 pipeline. Figure 6-1 presents the proposed routing for the Summit Carbon pipeline within the five affected states.[48]

The Summit Carbon project experienced continued delays and regulatory hurdles, particularly in South Dakota. Iowa and North Dakota issued permits in August and November of 2024, respectively, and Minnesota issued approval in December 2024.[49] The company is still seeking permit approval in South Dakota and faces legal challenges in several states

[44] https://www.reuters.com/sustainability/climate-energy/navigator-co2-ventures-cancels-carbon-capture-pipeline-project-us-midwest-2023-10-20/
[45] https://www.reuters.com/article/business/energy/south-dakota-regulator-rejects-navigator-co2-ventures-carbon-pipeline-applicatio-idUSKBN30D18N/
[46] https://www.reuters.com/sustainability/navigator-co2-ventures-asks-iowa-pause-ccs-pipeline-permit-process-2023-10-02/
[47] https://carbonherald.com/wolf-carbon-solutions-abandons-carbon-pipeline-plans-in-iowa/
[48] https://www.desmoinesregister.com/story/money/business/2024/06/27/summit-carbon-pipeline-map-iowa-utilities-board-what-is-a-carbon-pipeline/74216858007/
[49] https://carbonherald.com/summit-gets-the-green-light-for-carbon-capture-pipeline-in-minnesota/

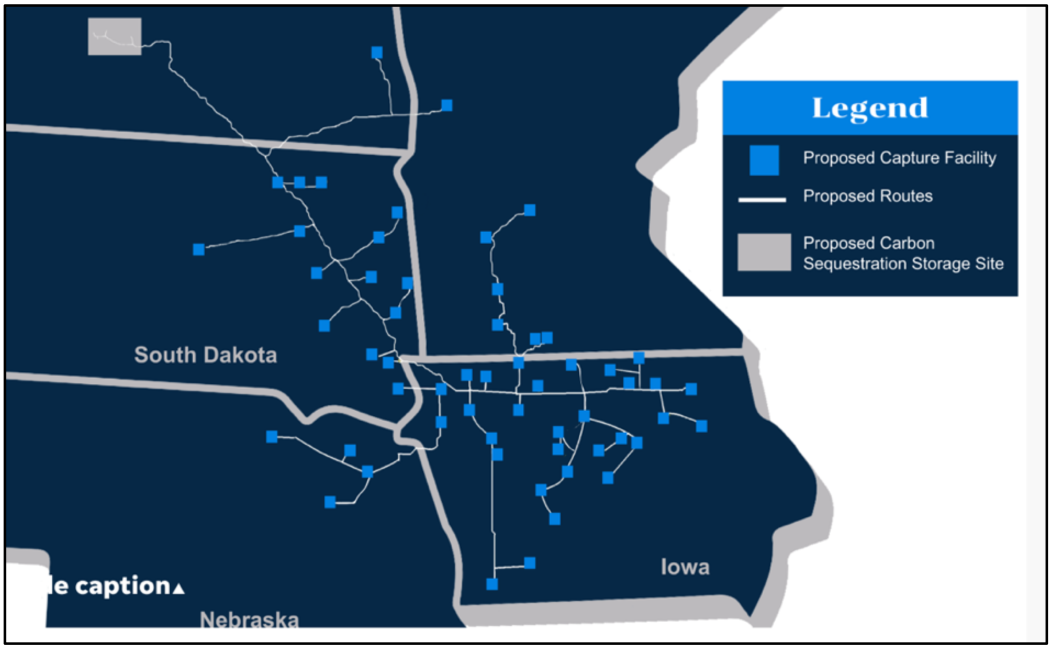

Figure 6-1. Proposed Summit CO_2 Pipeline Routing: Five States

In South Dakota, after an initial application was rejected, Summit reapplied after altering pipeline routing to minimize barriers. Despite this change, the South Dakota Public Utility Commission voted 2-1 to reject the revised route proposed.[50] A key factor is a new state law addressing eminent domain. Summit plans to alter the pipeline routing again, abandoning the most challenging elements of the route and negotiating directly with individual landowners on the most essential aspects of the pipeline.

Summit also faced legal challenges regarding the pipeline's classification as a "common carrier" which enhances the ability to invoke eminent domain to acquire land.

Conclusion. Resistance to CO_2 pipelines proposed by Navigator and Wolf Carbon has forced, at least for now, reconsideration of these projects, despite the projected benefits to the local economy of supporting the ethanol-based production facilities in these states. It is possible that any change in the 45Q tax provisions will further erode the feasibility of these projects.

Only Summit Carbon Solutions remains an entity that, at present, with permits from 4 states in hand, continues to pursue CO_2 pipelines.

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[50] https://carbonherald.com/south-dakota-regulators-block-summits-8-9b-carbon-capture-pipeline/#:~:text=Summit%2C%20which%20has%20already%20invested%20more%20than,would%20refile%20with%20a%20revised%2C%20smaller%20route.

Attachment 2

Analysis of Combustion Turbine CO_2 Emission Rates
Under the 2024 Greenhouse Gas (GHG) New Source Performance Standards (NSPS)
for Fossil-Fired EGUs

Prepared for:

American Public Power Association
Midwest Ozone Group
Power Generators Air Coalition

Prepared by

J. Edward Cichanowicz
Saratoga, CA

Michael Hein
Hein Analytics, LLC
Whitefish, MT

August 4, 2025

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Section 1 Introduction and Summary

On June 17, 2025, the Environmental Protection Agency (EPA or Agency) issued its proposed *Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units* rule.[1] The Proposed Rule, under its primary approach, seeks to repeal all greenhouse gas (GHG) emission standards for fossil-fueled power plants. EPA is also proposing, as an alternative, to repeal a narrower set of requirements. However, among other items under the alternative approach, the Agency is not proposing to revise the "Phase 1" carbon dioxide (CO_2) new source performance standards for stationary combustion turbines (CTs).[2] Rather, the Agency is soliciting comments on the best system of emission reduction (BSER) or standards of performance and related requirements for new and reconstructed intermediate load and low load fossil-fired stationary combustion turbines (Alternative Proposal C-13 and C-14, respectively). The current Phase 1 performance standards are based on a 12-month rolling average rate in pounds of CO_2 per megawatt hour (lbs/MWh), the specific values of which depend on (1) the 12-month capacity factor (i.e., low, intermediate, and base load) and (2) fuel. This analysis examines CO_2 rates for natural gas-fired simple-cycle CTs (in the intermediate load category) and combined-cycle CTs (in the base load category). Similar concepts would apply to other fuels, including diesel oil.

This report provides comments (in response to Alternative Proposal C-13 and C-14) based on publicly available information, including the current rule issued May 4, 2024[3] and the associated rulemaking docket.

A review of this material shows EPA's methodology for selecting Phase 1 standards for simple cycle and combined cycle CO_2 emission rates is flawed, as is the economic evaluation upon which EPA relied to draw the line for base load units (which EPA assumes are always combined-cycle units) at an annual capacity factor of 40%.

First, EPA does not account for how combustion turbine design variants affect CO_2 emission rate in the selection of an appropriate standard. Although EPA recognizes the different turbine designs – such as the E-, F-, H-, and J-Class and aeroderivative variants – the Agency does not consider such differences in selecting the CO_2 emission rate. The inherent emission rate differences between these various designs can be estimated, initially, by comparing the performance specifications of the combustion turbine suppliers (i.e., thermal efficiency—and therefore CO_2 emission rates—at high load under ISO[4] conditions), adjusted to account for the impact of a real world environment of non-ISO conditions; duty cycle; component degradation;

[1] 90 Fed. Reg. 25,752 (June 17, 2025) (Proposed Rule).
[2] More specifically, the current rule contains efficiency-based standards of performance for intermediate load CTs and as "Phase 1" standards for base load CTs. This report refers to both as the "Phase 1" performance standards.
[3] 89 Fed. Reg. 39,798 (May 9, 2024).
[4] ISO (International Organization for Standardization) conditions for testing combustion turbines are 15° C, 60% relative humidity, and sea level elevation.

ambient temperature; etc.[5] This analysis estimates both a "mean" and maximum" adjustment to apply to the high-load, ISO thermal efficiency specified by the supplier, and finds the median adjustments of 13-16% and maximum adjustments of approximately 22-24% comport with actual data measured for different turbine design categories.

Second, reviewing CO_2 emissions obtained from the EPA Air Markets Program Data (AMD) and the specific CTs show that complying with the present CO_2 emission rates is not based on broadly available technology. Specifically, many simple cycle CTs operating between 20% and 40% capacity factor are challenged to meet the emission rate of 1,170 lbs/MWh, as it is derived from an unrepresentative subset of units. Similarly, the present limit for CTs in combined cycle and at base load of 800 lbs/MWh (up to 900 lbs/MWh for small units) is not based on broad industry practice or available options. Specifically, for simple cycle CTs, the CO_2 emission rate is based on the aeroderivative class, despite EPA intending this rate to be applicable to frame turbines designed to generate seven times more power. EPA cites three aeroderivative turbine designs by supplier and model – two reflecting the very best thermal performance by any simple-cycle CT – and effectively requires that all units in the population (even those seven times larger, with very different designs) meet the same limit. There are many differences in the design attributes of aeroderivative turbines that distinguish them from large frame units that cannot be "scaled" to larger sizes. Most noteworthy, EPA does not recognize that aeroderivative units (which are typically small) can employ air compressors that create combustor inlet pressures up to 45 times that of the ambient air, elevating thermal efficiency by 2-3 percentage points above that achievable by frame turbines of intermediate generating capacity (150-350 MW). The broad population of simple cycle turbines cannot achieve such thermal performance. The net result of the current intermediate-load standard is largely to prohibit the construction of some aeroderivative CTs and most E-, F-, H-, and J-Class frame CTs (except perhaps the very largest H-Class units) for intermediate load duty.

Regarding combined cycle applications, EPA notes the actual CO_2 emission rate of the population ranges from 720 to 920 lbs/MWh, averaging 810 lbs/MWh. EPA implements so-called "adjustments" to the CO_2 emissions from these plants, correcting for different arrangement of combustion turbines and steam turbines. These adjustments range from accounting for a 1% advantage for a 2x1 arrangement compared to a 1x1 arrangement, a 1.4% advantage of wet versus dry cooling towers, and estimating any emissions increase observed at 40% duty cycle.[6] After these corrections, EPA then reverts to identifying the Dresden Plant in Ohio as a "best-performing" unit, emitting 770 lbs/MWh, enabled in part by the use of a wet cooling tower for which obtaining a permit in the present environment is challenging. EPA

[5] Gas Turbine World 2025 Performance Specs. Hereafter GTW 2025. https://gasturbineworld.zinioapps.com/reader/readsvg/658297/Cover. Note that CO2 emission rates are a direct function of a CT's thermal efficiency, or heat rate. This report uses a conversion factor of 117 lb CO_2 lb/MMBtu.

[6] As EPA uses the term, "'duty cycle' is the ratio of the gross amount of electricity generated relative to the amount that could be potentially generated if the unit operated at its nameplate capacity during every hour of operation. Duty cycle is thereby an indication of the amount of cycling or load following a unit experiences (higher duty cycles indicate less cycling, *i.e.,* more time at nameplate capacity when operating). Duty cycle is different from capacity factor, as the latter also quantifies the amount that the unit spends offline." 89 Fed. Reg. at 39,853 n.359.

concludes the revised database and experience from Dresden justify a CO_2 emission rate of 800 lbs/MWh rate. In doing so, EPA does not explain why any unit that does not use the specific design of the Dresden CTs, that is subject to different ambient or operating conditions than Dresden, and that is operated differently than Dresden (for example, experiencing more startup and shutdown cycles, more frequent load changes, or operation at a lower operating factor) can meet the selected standard.

Finally, EPA in the 2024 rulemaking employed a 2023 NETL study[7] to create numerous reference cases to justify 40% capacity factor as the intermediate load threshold. An overarching concern is that such "static" studies do not always reflect the present marketplace, and can be misleading. In other words, the results of EPA's own study could be very different in the future, if natural gas prices change, for example, or for a number of other reasons. Separate from that concern, EPA had to create four "new" reference cases to support its position by implementing numerous extrapolations and adjustments to the NETL reference cases, almost all of which introduce significant error. These "new" reference cases created by EPA compare the levelized cost of electricity (LCOE) from a simple and combined cycle unit. Results show these units generate equivalent LCOE at 40% capacity factor – but just barely, and likely not supported by the margin of error, as differences range from negligible to 2%. Based on the trends in LCOE extrapolated from the NETL study, EPA established a yearly capacity factor of 40% as the cutoff between intermediate load and base load categories, in effect mandating that any new simple-cycle CT is prohibited from operating at a capacity factor higher than 40%.

This analysis presents an alternative approach to analyzing LCOE at different capacity factors, using a more recent Energy Information Administration (EIA) study.[8] This approach requires only a modest extrapolation to create one "new" reference case. The sole extrapolation scales capital cost and operating variables of a 650 MW combined cycle to 450 MW – well within the range of generally accepted scaling criteria. No other adjustments or extrapolations are required. These EIA-derived results show that for conditions of unit lifetime, scaling factor for capital cost, and natural gas price only slightly different from EPA's but equally reasonable, simple cycle and combined units generate at equal LCOE at greater than 50% capacity factor. Consequently, the use of 40% capacity factor as the threshold for practically requiring a combined-cycle configuration is not justified.

After this introductory section, four additional sections comprise this report. Section 2 presents the results of calculations using suppliers' specified heat rates, adjusted based on an industry observer data to reflect real-world duty. Section 3 presents actual results from the AMD as evaluated by EPA, and independently by this study. Section 4 identifies how EPA established the basis for the proposed CO_2 emission rate limits for simple and combined cycle CTs. Section 5 critiques EPA's economic study used to justify the 40% capacity factor threshold for base load operations and performance standards (i.e., simple-cycle prohibition), and introduces an alternative approach.

[7] Cost and Performance Baseline for Fossil Energy Plants, Volume 5: Natural Gas Electricity Generating Units for Flexible Operation, National Energy Technology Laboratory, May 2023.
[8] Energy Information Agency, Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies, January 2024.

Section 2. Combustion Turbine Supplier Performance Specification

Introduction

Section 2 provides background information that demonstrates how the design of a combustion turbine (CT) fundamentally determines the CO_2 emission rate per MWh of output for any particular CT. The thermal efficiency of the combustion turbine drives the CO_2 emission rate of a CT. Each CT has an inherent thermal efficiency, typically expressed in terms of British Thermal Unit (Btu) per kilowatt-hour of output (Btu/kWh). This metric is also referred to as heat rate, typically specified by the manufacturer at full-load, under ISO conditions. At any given point in time, however, the thermal efficiency of the CT is affected by a multitude of factors, among them: (1) the operating load; (2) degradation (both unrecoverable and between maintenance cycles); (3) altitude; (4) ambient temperature; and (5) design margin. Simple-cycle CTs are also affected by inlet/outlet pressure losses, while combined-cycle CTs are also affected by air inlet fouling and steam condenser conditions.

This discussion provides key background information describing how the five major categories of combustion turbine design – aeroderivative and four "frame" classifications – compare. The analysis starts with suppliers' performance specifications for commonly deployed combustion turbines in both simple and combined cycle, operating at ISO, full load conditions. These data are subjected to two comparisons. First, these theoretical (specification) performance metrics are adjusted to reflect real-world operation due to changes in load, ambient temperature and elevation, component wear, inlet compressor fouling, and other factors. These adjustments are implemented based on experience assimilated by the industry trade publication, the *Gas Turbine World 2025 Performance Specs* report, and a technical paper by a supplier. Second, the adjusted performance specifications are compared to CO_2 emissions as calculated from EPA Air Markets Program Data (AMD)[9] for commercially operating units, per turbine frame design.

Combustion Turbine Population

The *Gas Turbine World 2025 Performance Specs* report describes performance data for the population of combustion turbines generating 25 MW or more and operating at 60 Hz.[10] The report introduces adjustment factors addressing the impact of operating load, startup and shutdown, ambient temperature, site elevation, component wear, and other factors. The authors note these adjustment factors should not be used to base a design or component selection, but to

[9] Strictly speaking, CO_2 is not directly measured but determined from assumed heat content, fuel flow and EPA's CO_2 emission factor for natural gas (i.e., 117 lb CO_2/MMBtu for pipeline-quality natural gas).
[10] GTW 2025. https://gasturbineworld.zinioapps.com/reader/readsvg/658297/Cover.

provide insight that should be validated by contact with the supplier, or further study.[11] Additional insight into the role of several of factors is also provided by publications in the trade press[12] and by a supplier of combustion turbines.[13] This evaluation uses the *Gas Turbine World 2025 Performance Specs* adjustments to provide insights into the likely ability of various CT models currently available on the market to meet the 2024 Phase 1 standards, assuming their operation and other conditions are within the experience reflected in these publications.

For the purposes of this evaluation, a subset of combustion turbines consisting of 27 units in simple cycle mode is considered from four suppliers. Table A-1 in Appendix A provides the suppliers' specification for generating capacity and heat rate for these units. A total of 22 of these same combustion turbines are arranged by their suppliers in a combined cycle mode, representing over 40 different generating units. Table A-2 summarize these units according to various arrangements with heat recovery steam generators (HRSG) and steam turbines. For example, combustion turbines can be configured in a "1 x 1" arrangement (e.g. 1 combustion turbine, HRSG, and steam turbine) or a "2 x 1" arrangement with two combustion turbines/HRSGs and one steam turbine. Appendix A also includes several "3 x 1" arrangements.

The CO_2 emission rate is calculated from the supplier specification, per usual practice reported in terms of Lower Heating Value (LHV) of the fuel. EPA's CO_2 performance standards, however, are based on fuel carbon content per Higher Heating Value (HHV). Consequently, this analysis will (a) employ a fuel carbon content of 117 lbs/MBtu HHV,[14] and (b) adjust the heat rate specified by suppliers by a nominal 11% to account for the difference in natural gas HHV versus LHV. Using the CO_2 content of natural gas, CO_2 emission rates from simple and combined cycle units are calculated under the specified conditions (ISO, full load, new and clean surfaces, and no component wear).

Operating Factors

The CO_2 emission rate is calculated using supplier specification (as discussed above) and adjusted to reflect real-world operating conditions, as reported in the *Gas Turbine World 2025 Performance Specs* and a technical paper by a supplier.[15] These adjustments are summarized in Table 2-1 for simple cycle[16] and Table 2-2 for combined cycle.[17]

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[11] Ibid. For example, regarding the role of operating load on unit heat rate, the authors note the following on page 7. The curves presented here are intended only for instructive and preliminary estimating purposes. When appropriate in your studies, contact OEMs for a complete and accurate analysis…".
[12] The role of ambient temperature and altitude also described in literature: https://www.power-eng.com/operations-maintenance/why-keeping-cool-keeps-output-high/
[13] Advanced Technology Combined Cycles, GE Power Systems, GER3936A. Hereafter GE3936A.
[14] Small changes in natural gas carbon will change CO_2 generation rate. EPA assumes a fixed carbon content from natural gas and 100% conversion to CO_2 to establish the carbon balance for Part 75 calculations. Natural gas carbon content is affected by the content of higher carbon constituents and lower hydrogen-content constituents such as pentane, can alters CO_2 generation rate per MBtu.
[15] GE3936A
[16] GTW 2025. At 7.
[17] Ibid. At 18.

Table 2-1. Simple Cycle "Real World" Heat Rate Impacts: Operating Factors

Factor	Heat Rate Impact	Mean Impact (%)	Maximum Impact (%)
Operating Load (fraction of capacity)	4% increase in heat rate at 80% load[18]	3.5	8
Degradation	2-6% loss in 24,000 hrs; restorable to within 1-1.5% of design	4	6
Altitude[19]	3.5% loss in power = each 1,000 ft above sea level		
Ambient temperature	0.1% increase in heat rate = each 1ºF above ISO	0.5	1.6
Inlet/Outlet losses per incurred air or gas pressure drop	0.2% increase in heat rate with each 1 inch w.g. increase in inlet/output pressure drop	0.8	1.6
Design Margin	3-5%	4	5
Total		12.8	22.2

Table 2-2. Combined Cycle "Real World" Heat Rate Impacts: Operating Factors

Factor	Impact	Mean Impact (%)	Maximum Impact (%)
Operating Load (fraction of capacity)	4% increase in heat rate per cycling, frequent startup/shutdown.	4	6
Degradation	3-5% loss in 10-15 Years	4	5
Altitude	0.2% increase in heat rate = each 1,000 ft above sea level	0	1.2
Ambient temperature	0.5% higher heat rate = per 10ºF above ISO	0.25	0.8
Air Inlet Fouling	1.2% increase in heat rate, not recoverable	1.2	1.8
Condenser (Heat Removal)	1% increase in heat rate per 0.5-inch Hg absolute pressure[20]	2 (per 1.0 in Hg	4 (per 2 in Hg
Design Margin	3-5%	4	5
Total		15.5	23.8

[18] GE3936A. Figure 3.
[19] Altitude results in a loss of maximum power output for a simple cycle combustion turbine, as reported above. It is unclear whether altitude also affects heat rate. This evaluation assumes no impact on heat rate from altitude.
[20] Ibid. Table 1 describes "new and clean" as 1.2 in Hg absolute; means and maximum impact values assumed as 1 and 2 in Hg absolute, respectively.

Table 2-1 summarizes the detrimental effects on heat rate for simple cycle combustion turbines due to five operating factors. These include operating load, component degradation, host site altitude, annual ambient temperature, and combustion air intake pressure drop. For each of these operating factors, the range cited in the *Gas Turbine World 2025 Performance Specs* augmented with a combustion turbine supplier's paper is reported. Two example cases are defined, reflecting "mean" conditions based on intermediate or mean values of the ranges listed in Table 2-1, and a "maximum" case based on the highest values in the range. The mean values of the heat rate detriment assigned are 3.5% for part load operation and startup/shutdown, 4% for component degradation, 0.5% to reflect units with ambient temperature elevated by 10ºF (e.g. from 59ºF to 69ºF), and 0.8% for a total of 4 in w.g. inlet air pressure loss. Including an additional 4% compliance margin (intermediate to the 3-5% design margin offered by GE in comments submitted in 2024).[21] In total, a mean total detriment of 12.8% is estimated.

The maximum values observed are 8% for part load operation and startup/shutdown, a 6% for component degradation, 1.6% to reflect units with ambient temperature elevated by 20ºF (e.g. from 59 to 79ºF), and 1.6% for a total of 4 in w.g. inlet air pressure loss. Per GE recommendations, the additional design margin of 5% is assigned, resulting in a total 22.2% detriment. (An additional compliance margin is not included in these example cases).

Table 2-2 similarly summarizes the detriment to heat rate for combined cycle combustion turbines due to operating factors analogous to simple cycle, but accounting for steam cycle heat rejection. These include operating load, component degradation, host site altitude, annual ambient temperature, combustion air intake pressure loss, and fouling of the condenser dedicated to heat rejection. The cumulative detriment to heat rate based on the mean values in Table 2-2 is 4% for part load and startup/shutdown operation, 4% for component degradation, 0.25% to reflect units with ambient temperature elevated by 10ºF (e.g. from 59ºF to 69ºF), 1.2% for inlet air fouling pressure loss, and an additional 2% to account for a 1 inch Hg absolute penalty in steam cycle condenser pressure drop. Including an additional 4% design margin (intermediate to the GE report of 3-5%) a total detriment of 15.5% is estimated.[22]

For the maximum values in Table 2-2, the cumulative detriment is 6% for part load and startup/shutdown operation, 5% for component degradation, 1.2% to reflect a unit at 6,000 feet of altitude, 0.8% to reflect units with ambient temperature elevated by 10ºF (e.g. from 59ºF to 69ºF), 1.8 % to reflect inlet air fouling loss, 4% to account for a 2-inch Hg absolute steam cycle condenser pressure loss. The maximum margin of 5% as advised by GE is also included, resulting in a total 23.8% detriment.

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[21] GE Verona Comments, Docket No. EPA-HQ-OAR-2023-0072. At 48. Hereafter GE 2023 Comments.

[22] The role of operating factors on CO_2 emission rate, as documented by the *Gas Turbine World 2025 Performance Spec* and summarized in Tables 2-1 and 2-2, demonstrates CO_2 emission rate from any CT is determined not only by design but also by operating factors - many out of control of the operator. By basing the standards on the performance of certain units operating under specific operating factors (without accounting for the variability of factors outside the control of the operator or how operators may use their units differently elsewhere or in the future), EPA essentially incorporated these factors into its Best System of Emission Reduction (BSER) determination. This is inconsistent with the historical methodology, which depends primarily on process equipment design and performance, not restrictions on equipment operating factors.

CO_2 Emission Rates: As Calculated

The combustion turbine performance specifications and adjustments to heat rate due to operating factors, as defined in Tables 2-1 and 2-2, are used to calculate the CO_2 emission rate. These calculations are presented in Figures 2-1 and 2-2 for simple and combined cycle, respectively.

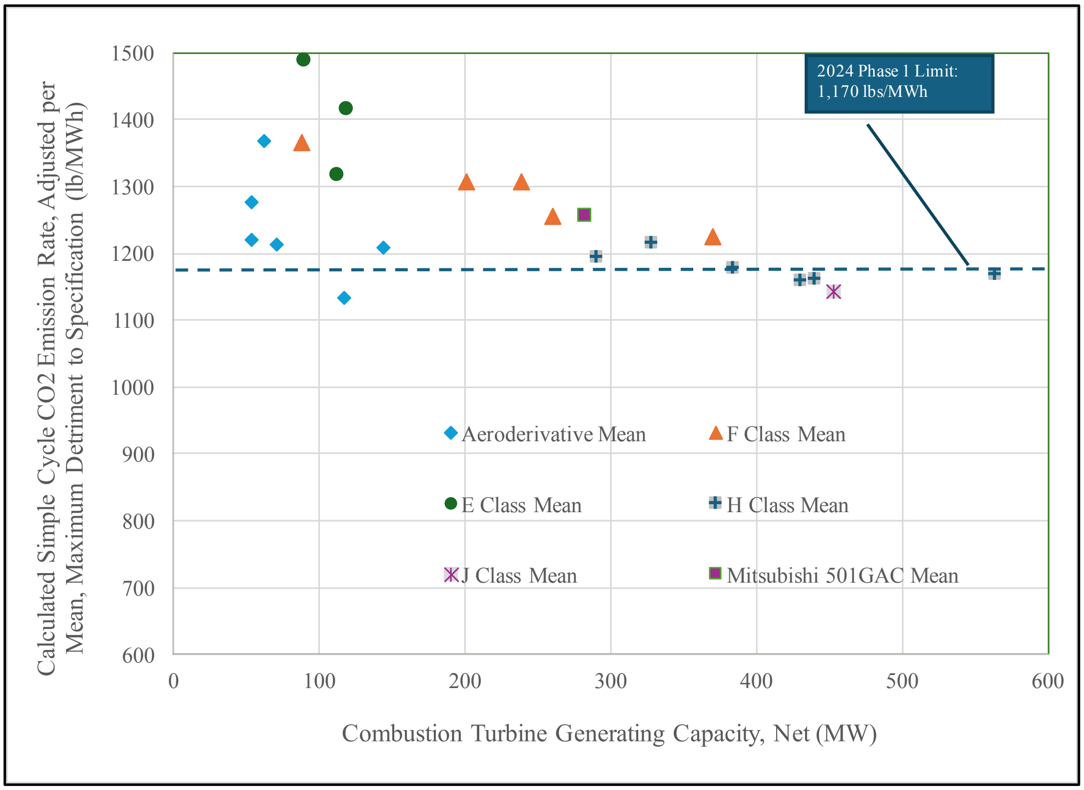

Figure 2-1. Calculated CO_2 Emission Rate: Simple Cycle

Simple Cycle

Figure 2-1 reflects the calculated CO_2 emission rate for the various combustion turbine designs designated in Appendix Table A-1. The mean value as determined from Table 2-1 is presented for each turbine classification, with data from each turbine class represented by the same marker and color. Figure 2-1 shows that based on the suppliers' specification and Gas Turbine World adjustments, a limited number of large H-Class, J-Class, and aeroderivative CTs, with the mean adjustment values are theoretically expected to have lower CO_2 rates than the current Phase 1 CO_2 emission standard of 1,170 lbs/MWh. However, no simple cycle CT with maximum adjustment (data not plotted for simplicity) can, even theoretically, meet the limit. A notable number of designs – in particular E-Class and F-Class models, and most aeroderivative designs – have specification CO_2 emissions rates adjusted by the mean value equal to or exceeding the 2024 Phase 1 CO_2 standard of 1,170 lb/MWh.

As a result, it appears that the 2024 Phase 1 CO_2 emission standard of 1,170 has the effect of prohibiting the use of a significant number of CT designs – several aeroderivative; all E-Class and F-Class, and most H-Class – as simple-cycle CTs operating at intermediate load. These types of units are, effectively, relegated to low-load duty under the current rules.

Combined Cycle

The Figure 2-2 combined cycle CO_2 emission rates reveal a pattern like that for simple cycle CTs – some of the largest H-Class and J-Class units can theoretically emit at less than the CO_2 emission standard of 800 lbs/MWh for the mean adjustment to heat rate. Those CTs would have a very small compliance margin. All other CT designs would likely exceed the standard, even at mean adjustment. The calculated CO_2 emission rates using the maximum adjustment (data not plotted for simplicity) of all currently available CTs would exceed 800 lb/MWh. None of the E-Class or aeroderivative design combined cycle units can meet the 2024 Phase 1 standard for base load units (which increases to 900 lb/MWh for units with heat input less than 2,000 MMBtu/h), for either the mean or the maximum.

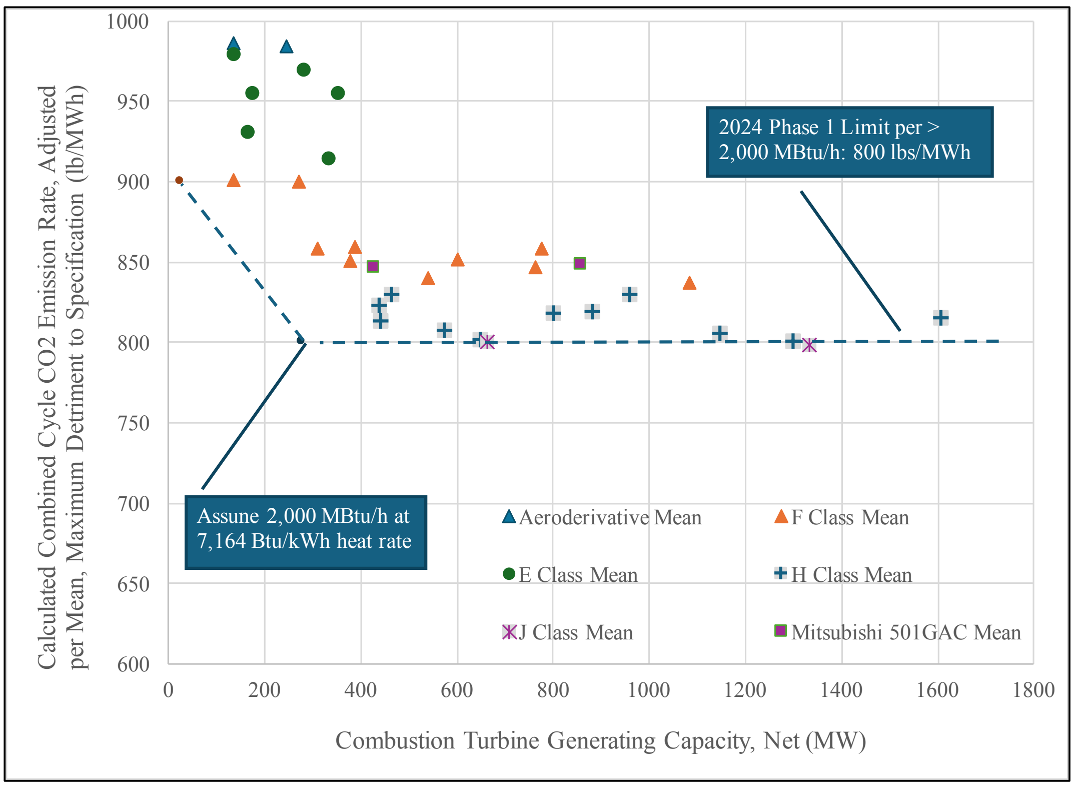

Figure 2-2. Calculated CO_2 Emission Rate: Combined Cycle

Reported Data

Reported actual CO_2 emission rates for combustion turbines is the third and possibly most significant comparison. Sections 3 and 4 of this report address data acquired from the EPA's AMD for two databases of populations of combustion turbines in the U.S. - one defined and used by EPA, and a second larger database used by this study. Prior to the Section 3 and 4 discussion of CO_2 emission rate trends with various operating factors, it is instructive to compare simple averages of CO_2 emission from the five design categories of turbine classes to those presented in

Figures 2-1 and 2-2. The results enable inferring an actual margin to compare with the observations offered by the *Gas Turbine World* and a supplier.

Both the EPA and this study considered simple and combined cycle units that commenced duty in 2015. Both the EPA and this study derived a database of reference units, which are screened to identify those simple cycle units operating at a minimum 12-month rolling capacity factor of 20%. EPA's database includes 87 simple cycle units of which 15 operated at 20% or more capacity factor, and 59 combined cycle units.[23] This study evaluated 146 simple cycle units of which 23 have operated at 20% capacity factor or more; and 72 combined cycle units. A further description of the differences in the databases is presented in Section 4. For both databases, the maximum CO_2 emission rate is determined over a 12-month rolling average.

The sources of data are as follows:

- Study Population: Commercial Service 2015-2023 natural gas-fired turbines CO_2 *Emission Rate = Sum of 2023-2024 CO_2 Mass (tons) divided by Sum of 2023-2024 Gross Load (MWh)*
- EPA Air Market Program Data: 2015 through 2023, Annual Basis
- EIA-860 – Unit Configuration, Size, Cooling Type, In-Service Date, Latitude/Longitude
- Capacity and Operating Factors: Same Basis
- Elevation Data: "Open Elevation" by lat/long
- Weather Data: "OpenMeteo" – annual, daily, hourly by latitude/longitude

The combustion turbine design category is not defined in these databases; such design information is acquired from files in EPA's Cross State Air Pollution Rule docket,[24] and augmented by a literature search and supplier information. These sources provide CO_2 emission from four of the five classes of turbines. The CO_2 emission rate and number of turbines in each design category are summarized in Figure 2-3 and the standard deviation of those emission rates are shown in Figure 2-4. These results are described as follows.

Simple Cycle

Aeroderivative. For 24 aeroderivative turbines operating at 20% capacity factor or greater, the CO_2 emission rate averaged 1,213 lbs/MWh. This actual, "as-observed" rate implies a real-world increase of 11% over the average of the suppliers' specification (i.e., at ISO and full-load) of 1,091 lbs/MWh. This average is relatively consistent with the 12.8% mean adjustment using *Gas Turbine World* and supplier data.

[23] EPA's database does not include generating units that entered commercial service after 2020; no rational is cited. This analysis, being able to access data through 2024, could include units that operated in 2021-2023 and have adequate data to calculate at least 12 data of 12-month rolling averages. Consequently, this study was able to utilize 78 additional units (69 simple cycle, 9 combined cycle).

[24] EPA EPA-HQ-OAR-2024-0419-0020_attachment_3. Available at https://www.epa.gov/Cross-State-Air-Pollution/cross-state-air-pollution-rule-csapr-regulatory-actions-and-litigation.

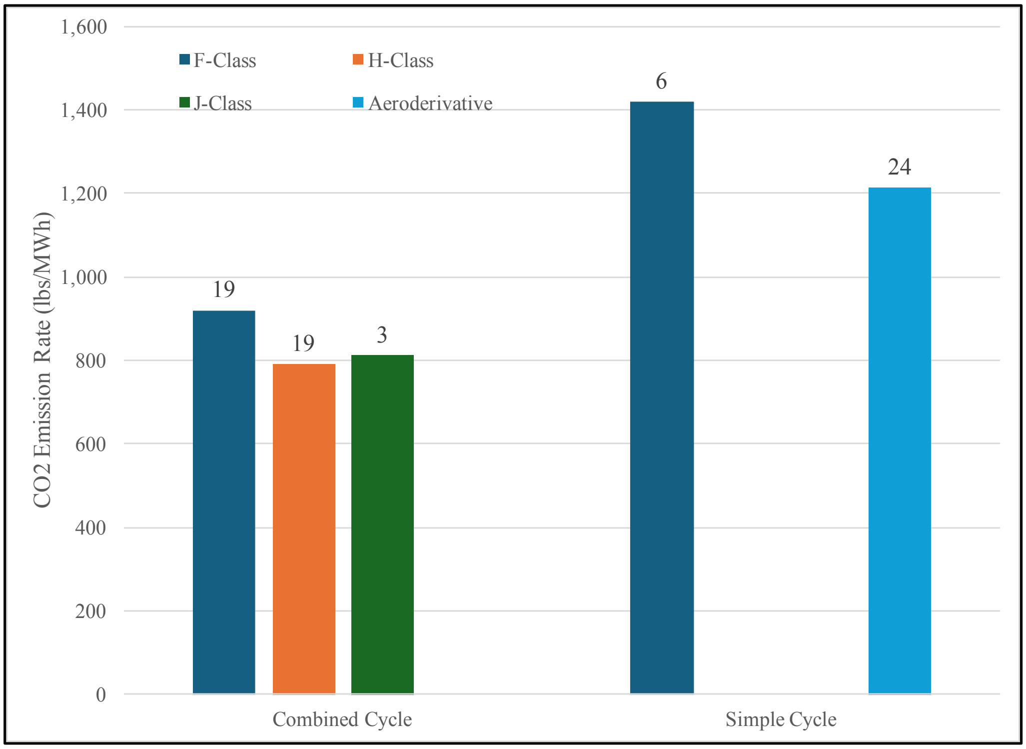

Figure 2-3. CO_2 Emission Rate from Turbine Design Categories: Simple, Combined Cycle

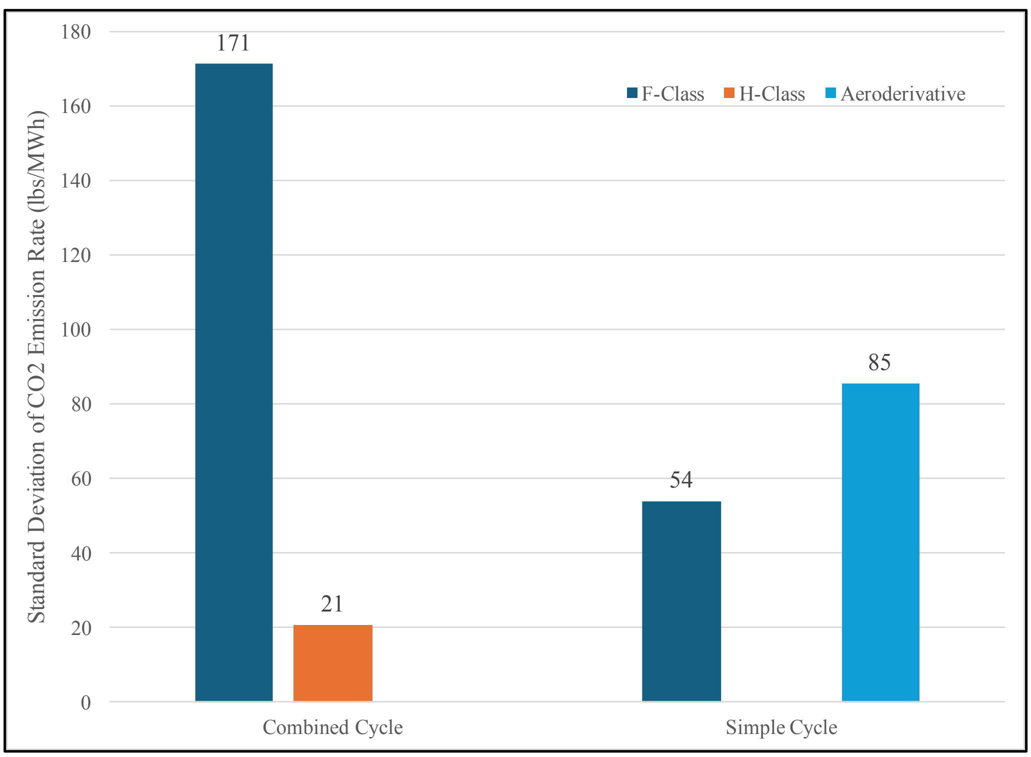

Figure 2-4 Standard Deviation of Maximum CO_2 Emission Rate per Categories: Simple, Combined Cycle

It is further insightful to consider the variability of this data by reviewing the standard deviation, or the CO_2 rate which 68% of the population either exceeds or is below the mean value. Figure 2-4 shows the standard deviation for the aeroderivative class is 85 lbs/MWh; implying nominally 7 units emit CO_2 at 1,298 lbs/MWh or greater, and the same number of units emit at 1,128 lbs/MWh or lower.

F-Class. These 6 units average 1,419 lbs/MWh of CO_2 emission, implying a 24% margin over the average of the suppliers' average specifications of 1,141 lbs/MWh. This real-world increase approximates the maximum of 22.2% of adjustment using *Gas Turbine World* and supplier data. These data exhibit a standard deviation of approximately 54 lbs/MWh; implying one or two units emit up to 1,453 lbs/MWh, and one or two 1,366 lbs/MWh or less.

Combined Cycle

The combined cycle data in Figure 2-3 are determined by design variables discussed previously. These are arrangements of the combustion turbine, HRSG, and steam turbine, and the use of wet or dry cooling tower. Sections 3 and 4 describe how these design variants affect the CO_2 emission rate.

F-Class. The 19 turbines within this category average CO_2 emissions of 920 lbs/MWh. The implied real-world increase for this category is 24% over the average specifications of 745 lbs/MWh, approximating the maximum adjustment of 23.8% using Gas Turbine World and supplier data. These data exhibit a relatively high standard deviation of 171 lbs/MWh, implying approximately 6 units emit more than 1,091 lbs/MWh, and the same number emit at 751 lbs/MWh or less.

H-Class. The 19 units comprising this category average 791 lbs/MWh of CO_2 emission. Many of these units are of the larger capacity 2 x 1 or 3 x 1 arrangement, biasing the CO_2 emissions rate low.[25] Any such bias to lower CO_2 is problematic for units with arrangement of 1x1, anticipated to be the most popular configuration. These emission rates imply a real-world operating increase of 12% over the average specifications of 706 lbs/MWh, approaching the mean adjustment of 15.5% using *Gas Turbine World* and supplier data. These data exhibit a relative small standard deviation of approximately 21 lbs/MWh.

J-Class. The three units present an average of 811 lbs/MWh; similar to H-Class these CO_2 emissions rates are influenced by combustion turbine and steam turbine arrangement. A real-world operating increase of 17% is implied, exceeding the mean adjustment using *Gas Turbine World* and supplier data. This population is too small to merit a meaningful standard deviation.

[25] Another complication of bias introduced by 3x1 and 2x1 arrangements is the impact when one or more turbines are off-line for service. This resulting configuration – even if operating for 4- 8 weeks –will affect the 12-month rolling average. This possibility is a basis for considering adequate design and operating margin in selection of CO_2 emission rate.

It should be noted that the use of duct burners, to increase power generation during periods of peak demand and adopted by approximately 75% of the combined cycle inventory,[26] can significantly affect heat rate. The heat rate impact can vary widely, from less than 1% to more than 3%.[27] However, the effect on the 12-month rolling average of CO_2 emission rate is less, as duct-firing is generally used only during periods of peak power and when justified by market electricity prices – perhaps 20% of operating time.[28] The data in Figures 2-3 and 2-4 probably reflects the impact of duct firing on the performance of the units in the population analyzed, although an explicit assessment of the contribution is not addressed in this evaluation.

Observations

Observations addressing the CO_2 emission rate specified by suppliers, with adjustments recommended by an industry trade publication to reflect "mean" and "maximum" expected real-world increases, and comparison to a sample of actual CO_2 data reported under the requirements of the Acid Rain Program (40 CFR Parts 72-75) are presented as follows:

- Calculated CO_2 emission rates, based on suppliers' design specifications and accounting for real-world heat rate impacts of operating factors, as observed by an industry publication, show CO_2 emission rates from simple and combined cycle duty vary considerably with the turbine design: aeroderivative, E-, F-, J-, and H- Class turbine.

- Observed CO_2 emission rates from a total of 30 simple cycle units, as derived from the AMD, imply an average adjustment factor to apply to the suppliers full-load/ISO CO_2 emission rate to reflect real-world data. The simple cycle data in Figure 2-3 imply an adjustment by approximately 11% for aeroderivative and 24% for F-Class units to reflect real-world operating duty. There is no data in AMD for E-Class and H-Class in simple cycle configuration. However, it is expected that both of these models will be used in these configurations in the near future and beyond.

- Observed CO_2 emission rates from a total of 41 combined cycle units, as derived from the AMD, imply an average adjustment factor to apply to the suppliers full-load/ISO CO_2 emission rate to reflect real-world data. The combined cycle data in Figure 2-4 imply an adjustment from 12% to reflect H-Class duty up to 24% to reflect F-Class duty.

The implications for meeting the 2024 Phase 1 standard for intermediate load (simple cycle CTs) and base load (combined cycle CTs) are summarized as follows:

- Simple Cycle. Figure 2-1 shows only one aeroderivative and several H- and J-Class units, using the calculated CO_2 emission rates based on the mean adjustment to specified heat rate, can meet the Phase 1 limit of 1,170 lbs/MWh; notably with little or no compliance margin. The use of the mean adjustment is corroborated by real-world data.

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[26] https://www.eia.gov/todayinenergy/detail.php?id=52778.
[27] The detriment to combined cycle unit heat rate due to duct burners is estimated to range from less than 1% to 3%. See https://www.power-eng.com/coal/combined-cycles-exploding-the-cookie-cutter-myth/.
[28] https://www.power-eng.com/gas/combined-cycle/advancements-in-duct-firing-technology/

- <u>Combined Cycle</u>. Figure 2-2 shows a limited number of F-, H-, and J-Class units can meet the CO_2 standard based of 800 lb/MWh, with little or no margin, based on suppliers' heat rate at ISO conditions and adjusted for mean detriments. The use of the mean adjustment is corroborated by real-world data.

Section 3. CO_2 Emission Rate Trends per Air Markets Program Data

Introduction

Section 3 reports trends in CO_2 emissions per MWh for both simple cycle and combined cycle units calculated from EPA's AMD. Data acquired from the AMD as used by (a) EPA to develop the 2024 Phase 1 Greenhouse Gas (GHG) New Source Performance Standards NSPS emission limits are presented, and (b) this study are both addressed. Differences in the universe of units evaluated are considered.

Both the EPA and this study derived databases of simple and combined cycle units that commenced duty in 2015 or later.[29] These databases considered all operating units, but for simple cycle only units operating at capacity factors of 20% or greater are considered in the evaluation. For combined cycle units, all but six operated at a capacity factor of 40% or greater and the units that operated at less than 40% capacity factor are excluded from the evaluation. The maximum CO_2 emission rate observed over the series of 12-month rolling averages since unit inception is calculated using the data sources listed in Section 2.

Reference Database

The database used by EPA differs from that utilized in this study. As described in Section 2, EPA's is comprised of 87 simple cycle and 59 combined cycle operating units.[30] This study identified 146 simple cycle and 69 combined cycle operating units. For simple cycle units that operate at 20% capacity factor or greater, EPA identified 17, while this study identified 23 units. Regarding combined cycle, all but six units in each database assembled by EPA and this study operated for at least one year above 40% capacity factor. Most of the difference in the population of the two databases appear to be due to a large number of units entering commercial service since 2021 that are not captured in the previous rulemaking by EPA.

Table B-1 in Appendix B lists the units in EPA's database not addressed in this study; Table B-2 lists units addressed in this study not considered by EPA.

Operating Features

Before considering the CO_2 emission rates of simple and combined cycle units, the characteristics of duty factor and operating factor are compared in Figures 3-1

[29] Units entering service in 2015 and thereafter likely reflect state-of-the-art technology, but (for the most recent of these units) may not capture the long-term role of component degradation with service time. Adequate margin in selecting CO_2 rates would address this uncertainty.
[30] EPA-HQ-OAR-2023-0072-0060_attachment_6

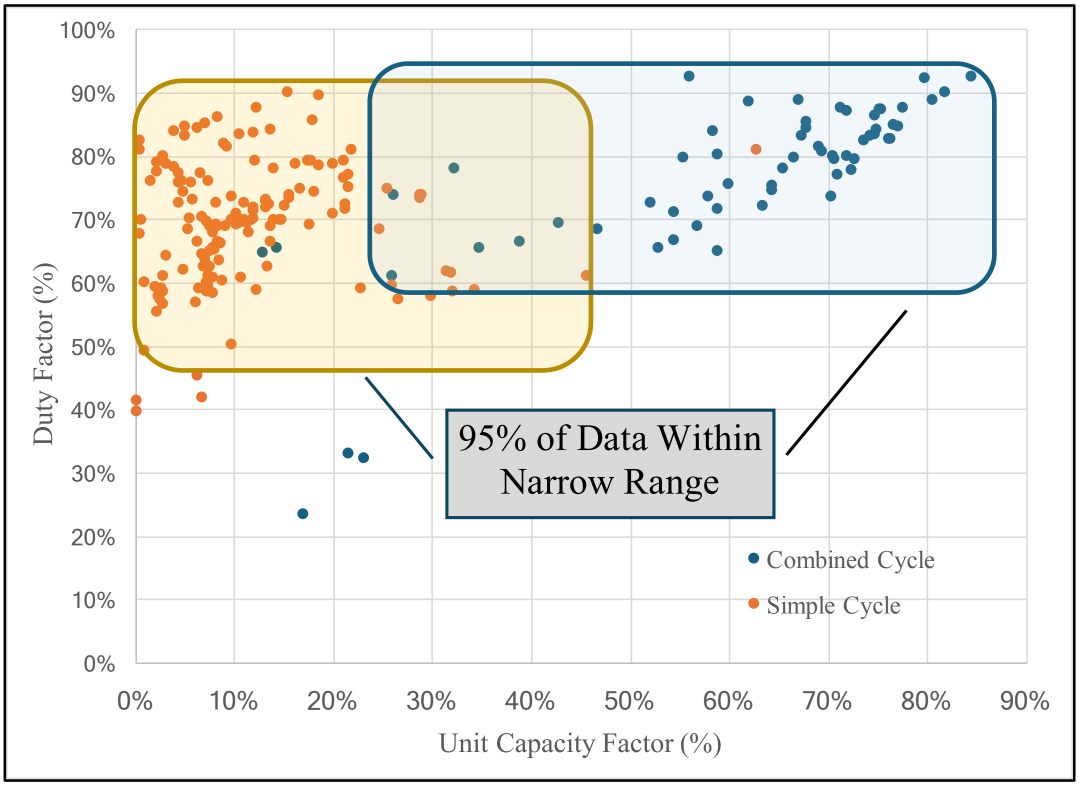

Figure 3-1. Combustion Turbine Operating Factor vs. Capacity Factor

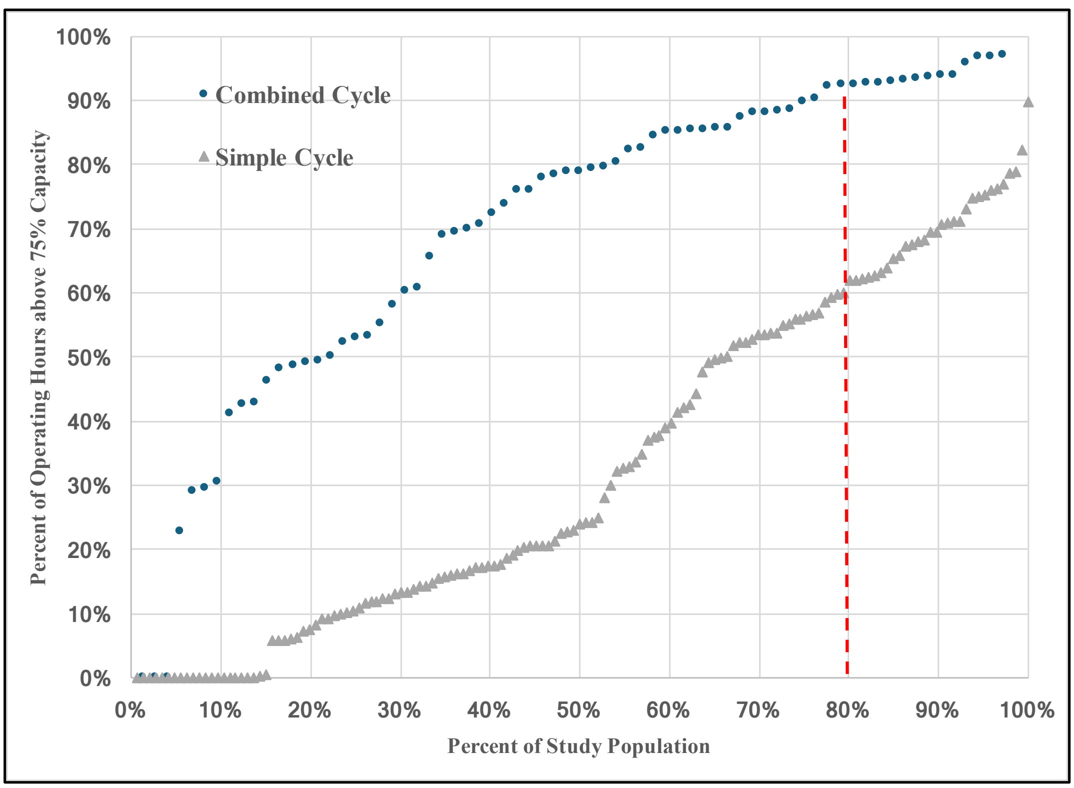

Figure 3-2. Percent Operating Hours Exceeding 75% Capacity: Simple, Combined Cycle

Figure 3-1 compares duty factor (what EPA calls duty cycle) and capacity factor for simple and combined cycle units addressed in this study, while Figure 3-2 reports the units' operations above 75% capacity factor. Figure 3-1 shows that although simple cycle units operate at much lower capacity factors than combined cycle, both types of units operate predominantly at high loads. The figure shows 95% of simple cycle units operate on average at 50 to 92% of maximum capacity (i.e., a duty factor of 50 to 92%). Combined cycle units exhibit a similar trend – 95% of units operate at an average of 58 to 94% of maximum capacity (i.e., a duty factor of 58 to 94%).

Figure 3-2 presents the cumulative frequency distribution of operating hours for simple and combined cycle units. Combined cycle units expend significant operating time at greater than 75% capacity – 80% of the units operate for 93% of the time as such. Eighty percent of the simple cycle units expend 60% of operating time at more than 75% capacity.

Additional discussion is presented according to each operating cycle as follows.

Simple Cycle

This study identified 146 simple cycle units firing natural gas from EIA and EPA sources as candidates for evaluation. Of this population, 30 units have operated between 20 and 40% capacity factor for at least one year, generating at least one relevant 12-month rolling average CO_2 emission rate. The maximum CO_2 emission rate for these 30 units over the qualifying 12-month rolling average periods is presented in Figure 3-3 as a function of unit nameplate generating capacity.

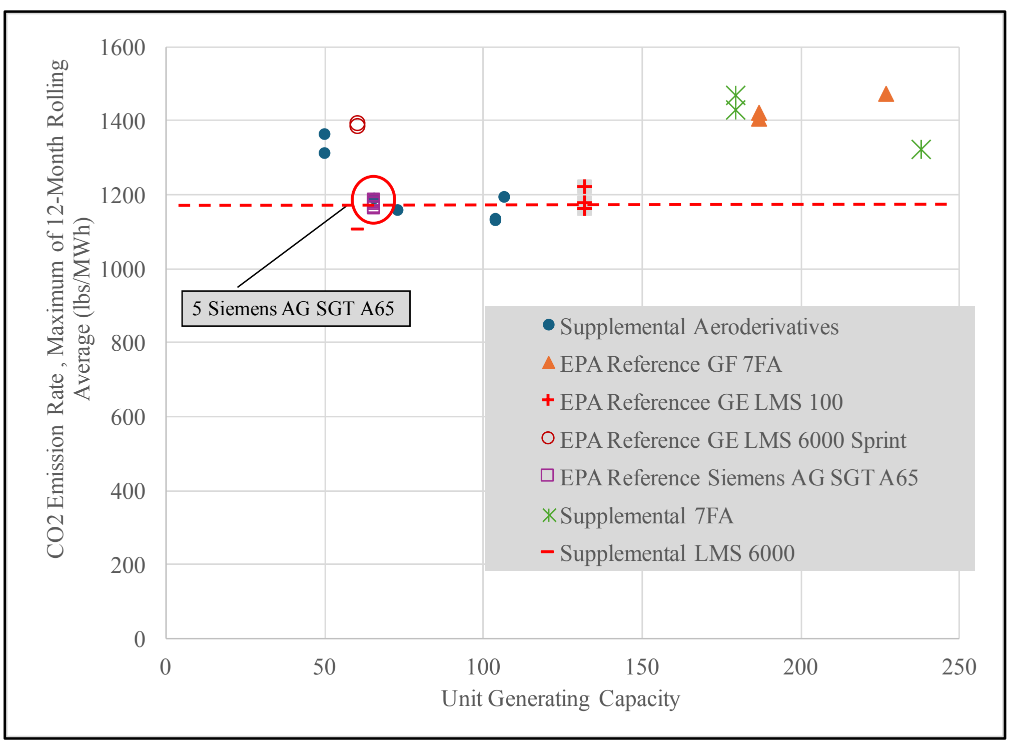

Figure 3-3. CO_2 Emissions Rate vs. Nameplate Capacity: 30 Simple Cycle Units Operating Between 20 and 40% Capacity Factor

The Figure 3-3 legend identifies data designated by EPA as references for the 2024 Phase 1 standard for simple cycle units operating at intermediate load. The legend also identifies the supplementary units introduced by this study. Notably, all of the units that can meet the intermediate load CO_2 performance standard are aeroderivative. Six of the 16 units cited by EPA are found to operate at or below the Phase 1 rate of 1,170 lbs/MWh (although 3 exceed by only 2 to 8 lbs/MWh). Three of the 14 supplemental units introduced by this study emit at less than the standard.

Combined Cycle

A total of 69 combined cycle generating units are identified from the EIA and EPA data and evaluated by this analysis. Of these, eight operated at an average 12-month capacity factor calculated over their operating years as less than 40%.

Figure 3-4 presents the maximum 12-month rolling average CO_2 emission rate (lbs/MWh) as a function of the nameplate generating capacity for units operating over 40% capacity factor. Of the 61 units in Figure 3-4, a total of 26 (42%) operated at CO_2 emissions rates that meet the 2024 Phase 1 GHG NSPS CO_2 emissions limit of 800 lbs/MWh. The average of all units in Figure 3-7 is 835 lbs/MWh. Notably, there are few combined cycle units that generate less than 250 MW capacity – and only one of a capacity of 100 MW or less. All of them emitted above the performance standard selected in the 2024 rule.

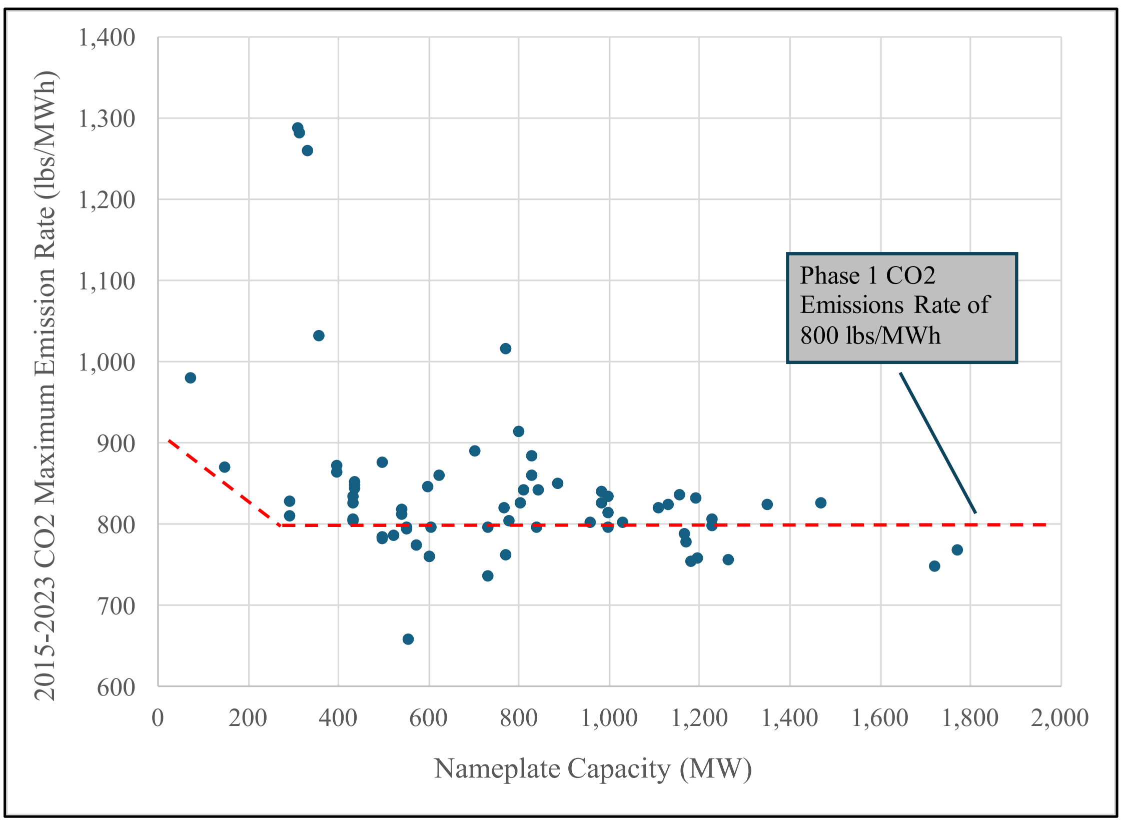

Figure 3-4. CO_2 Emissions Rate vs. Nameplate Capacity: Combined Cycle Units

Observations

The simple cycle and combined cycle databases used for this study identified more units than used by EPA and found more operating in the qualified range of capacity factors. The most notable difference is for simple cycle, in which 146 units identified as possible reference candidates, in contrast to 87 by EPA. Screening these units for capacity factor above 20%, the EPA database yielded 16 units while this study identified 30. This study also evaluated a greater number of combined cycle units – 69 compared to 59 cited by EPA. All but 8 units operated at a 12-month rolling average capacity factor of 40% and greater. The differences in the databases employed by EPA and this study appear mostly due to inclusion by the latter of numerous units that entered service in the last four years. Additional observations are offered as follows:

General

Although simple and combined cycle units exhibit very different capacity factors, their duty cycle is similar. For both categories of units, the duty cycle ranges from approximately 60% to more than 90%, showing that when in service these units tend to operate at high load.

Simple Cycle

CO_2 emission rates reported using AMD are generally higher than those calculated from suppliers' specifications, even when accounting for the real-world operating factors that negatively impact heat rate presented in Section 2. For approximately 65% of the units evaluated in this study, the maximum of the 12-month rolling average CO_2 emission rate exceeds the 1,170 lbs/MWh rate; no units exceeding approximately 175 MW range are able to comply with the 2024 Phase 1 intermediate-load emission standard. A description of how CO_2 emission rates are affected on design basis, focusing on the aeroderivative class versus F-Class, J- and H-Class, is addressed in Section 4. Only turbines entering service in the last 10 years are included in this analysis, thus long-term degradation of these units could not be determined from reported data. This uncertainty will likely further complicate meeting the standard.

Combined Cycle

Similar to simple cycle, CO_2 emission rates for combined cycle CTs reported using AMD are generally higher than those calculated from suppliers' specifications, including the mean and maximum margins presented in Section 2. For 26 of the 62 units operating at a 12-month average capacity factor of 40% or higher, the maximum of the 12-month rolling average CO_2 emission rate exceeds the 800 lbs/MWh rate. Consequently, 42% of 2015+ units do not achieve the output-based Phase I Base Load Subcategory CO_2 emission rate limit of 800 lbs/MWh. A description of how CO_2 emission rates are affected on design basis, focusing on the aeroderivative class versus F-Class, J- and H-Class, is addressed in Section 4.

Section 4. Critique of EPA Emission Rate Selection Methodology

EPA described in the final GHG rule the methodology by which the Phase 1 NSPS CO_2 emission performance standards are selected for both simple cycle (i.e., intermediate load units) and the combined cycle (i.e., base load units).[31] EPA's database employs 87 simple cycle and 59 combined cycle units; this study evaluated 146 simple cycle and 72 combined cycle units.[32]

The methodology for selecting these Phase 1 CO_2 emission rates is reviewed for both simple and combined cycle units.

Simple Cycle

EPA considered 16 units in their database to select a feasible CO_2 emission rate. Significantly, all were of aeroderivative design – with two exceptions, both GE 7FA turbines.

EPA determined the maximum 12-month average for each unit over the years of duty. For the 16 subject units, the CO_2 emission rate ranged from 1,156 to 1,470 lbs/MWh, with an average of 1,241 lbs/MWh. EPA acknowledges that most of the reference population is aeroderivative designs, with some units employing "intercooling" to lower compressor parasitic power, thereby increasing electricity generated and improving net heat rate. EPA also acknowledges that intercooling is not broadly applicable due to the need for a cooling tower and additional plant footprint.

Nonetheless, EPA in selecting a CO_2 emission rate of 1,170 lbs/MWh cites three reference aeroderivative turbine designs: (a) GE LMS100, (b) Siemens SGT-A65, and (c) GE LM6000. The relevant CO_2 emission rate data reported by EPA for these units show about half comply with the Phase 1 emission limit.[33] EPA did not identify any differences in design or operation that differentiated the noncompliant units from the compliant units.

This approach is deficient. First, within the three aeroderivative models that the EPA selected to base the standard on, eight out of a total of 16 units do not meet that standard. It is unclear why half of the turbines designated as references fail to standard – perhaps due to their operating history and other factors. These units' thermal efficiency is inherent to their design and cannot be

[31] 89 Fed. Reg. at 39,946-48.

[32] EPA's database does not include generating units that entered commercial service after 2020; no rational is cited. This analysis, being able to access data through 2024, could include units that operated in 2021-2023 and have adequate data to calculate at least 12 datapoints of 12-month rolling averages. Consequently, this study was able to utilize 78 additional units (69 simple cycle, 9 combined cycle).

[33] See EPA-HQ-OAR-2023-0072-0060_attachment_6, Worksheet "Chart Data", columns N, O, and Q.

changed. Some factors that can affect these units' 12-month rolling average CO_2 emission rate are out of their operators' control. These include site conditions and the associated ambient temperatures over a 12-month period, and hardware degradation between scheduled maintenance cycles. Most – if not all –- operators follow recommended maintenance practices, and thus have no control of the inherent degradation of the units and the associated compromise in thermal performance and whether such performance losses are recoverable between maintenance cycles. The operator has control of how to run the unit, but in practice market demand determines the dispatch and therefore the frequency of load changes, startup/shutdown events, etc.

EPA does not appear to have evaluated why half the aeroderivative CTs of the models referenced to set the performance standard did not meet that standard, and whether—even theoretically—these units could have done anything to meet the standard.

Second, EPA's reliance on only three specific aeroderivative models is even more problematic. Figure 4-1 presents the theoretical heat rate specified by the supplier (i.e., full-load, ISO conditions) for a sample of aeroderivative and intermediate capacity frame turbines broadly available in the U.S. Figure 4-1 calls out the three aeroderivative turbine designs designated by EPA as the basis of the 1,170 lb/MWh standard for intermediate-load simple-cycle turbines.

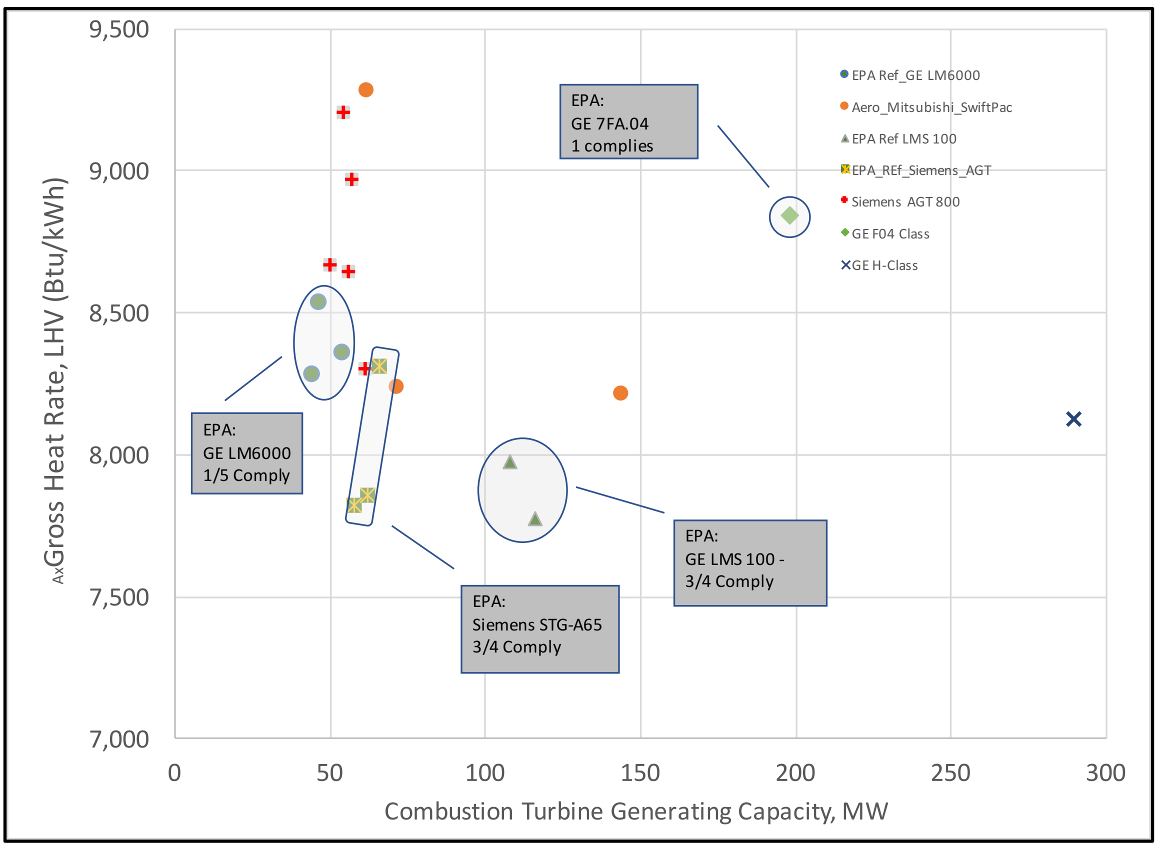

Figure 4-1. Combustion Turbines Suppliers' Specification of Gross Heat Rate: Aeroderivative and Frame Design of 50-300 MW

Putting aside the fact that half of the referenced model units did not meet the standard selected by EPA, any other CT model with an inherent (i.e., specification) heat rate exceeding that of the three aeroderivative models that EPA selected as the basis of the performance standard likely cannot meet the standard (at least not under operating duty and conditions similar to those experienced by the reference units). This includes many other aeroderivative models, as well as all E-Class and F-Class frame CTs, and all but the largest H-Class and J-Class frame CTs. All of these models are, effectively, limited to operating at low load (i.e., less than 20% capacity factor) because they cannot meet the intermediate load performance standard.

Figure 4-1 shows:

- EPA selected the two turbines with the lowest specified heat rate - the Siemens SGT-A65 and GE LMS100 to set the simple cycle CT CO_2 standard for units in the intermediate load subcategory. A third turbine – the GE LM6000 – presents similarly low specified heat rate in comparison to the remainder of the aeroderivative population. Almost without exception, the heat rates of all other aeroderivative-class turbines are higher. Establishing a 1,170 lb/MWh CO_2 emission rate standard effectively prohibits the use of aeroderivative-class turbine on the market for intermediate load duty, except for the three models favored by EPA.

- Many frame design turbines of 180-300 MW of generating capacity – representing likely candidates for simple-cycle applications in the U.S. – exhibit higher heat rates (and thus CO_2 emission rates). These turbines are desirable options for utilities due to their size, operating costs, and other operational factors. Several utilities have placed current orders for these units for several years out. EPA by setting the standard at 1,170 lb/MWh is effectively prohibiting the construction of most frame-design turbines with a capacity of 180-300 MW for intermediate load duty.

The aeroderivative design category does not represent the entire population of simple-cycle CTs. There are numerous differences in the design of aeroderivative compared to frame turbines – and not all the features of the former can be generalized or extrapolated to the latter. Most notably, aeroderivative turbines, due to their limited generating capacity and physical size, can utilize inlet compressors capable of delivering extremely high inlet pressures for combustion. This unique feature compromises EPA's near-exclusive use of this category as the reference case for simple cycle CO_2 emissions. The turbine inlet pressure is extremely important for this Brayton cycle – unlike the Rankine cycle deployed for fossil fuel-fired boilers and steam turbines, the simple cycle CT significantly benefits from high inlet pressure, elevating thermal efficiency. Inlet compressors for aeroderivative turbines elevate air pressure by a factor of 45-to-1 over ambient inlet pressure. Limits imposed by compressor suppliers on the maximum compressor blade "tip speed" prevent creating such high inlet pressures for frame turbines.[34] EPA did not identify high turbine inlet pressures as a component of BSER; clearly, this design feature influenced the choice of "highly efficient" units. However, as previously noted, the larger frame

[34] Compressor blade maximum tip speed is determined by the material strength and aerodynamic limits, which restricts rotational speed and the dimensions – and thus the power output - of the turbine. See *Gas Turbine Design Philosophy*, GE Power Generation, GE-3434D.

turbines requiring higher blade tip speed prevent this performance-enhanced feature from being applied on frame units.

Figure 4-2 compares the turbine inlet pressure ratio for aeroderivative and frame design turbines as a function of heat throughput. In the context of this discussion, the turbine inlet pressure ratio is the ratio of the air pressure delivered to the turbine combustor, relative to ambient air. This critical ratio for aeroderivative turbines (blue data and trend line) approaches 45, while for frame turbines this metric is limited to 25 (orange data and trend line).

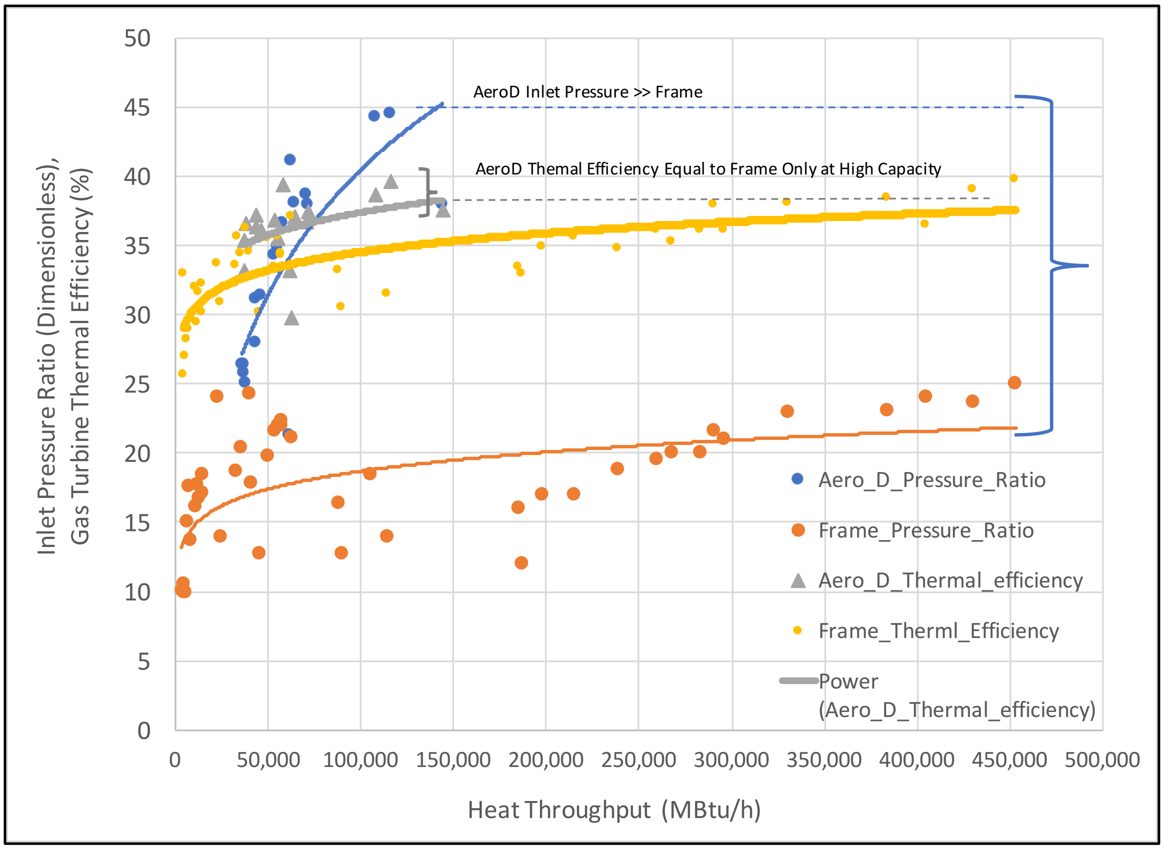

Figure 4-2. Combustion Turbine Inlet Pressure Ratio, Thermal Efficiency: Aeroderivative, Frame Designs

Figure 4-2 also shows the suppliers specified (inherent) thermal efficiency for each category of turbines. The figure shows that aeroderivative designs (gray data and trend line) enjoy higher thermal efficiency than frame designs (yellow data and trend line). Figure 4-2 also shows that the turbine inlet pressure ratio for frame turbines is well below that of aeroderivative – in many cases by half. As a result, the specified thermal efficiency of frame turbines in this category is less than aeroderivative by 2-4 percentage points. H- and J-Class units exhibit thermal efficiency approaching 40% – but only for these largest capacity turbines.

In summary, EPA's methodology of basing simple cycle CO_2 emission rates on aeroderivative turbines is flawed, as it allows the high inlet turbine pressure ratio achievable only on these smaller generating capacity units to drive the theoretical thermal efficiency of the CT and, therefore, its CO_2 emissions rate. Within the aeroderivative category, EPA selected among the most efficient units on which to base the standard. However, operating data show that the standard is not universally attained (in fact, it is attained by half of the aeroderivative population). EPA did not account for differences in units that could – and those that could not - attain the Phase 1 Intermediate Load limit.

Combined Cycle

EPA reviewed the emission rate data from 59 units in their database to select Phase 1 CO_2 emission standards for combined cycle units. EPA recognized the combined cycle CO_2 emission rate is affected by several design decisions, such as the arrangement of the combustion turbine, the HRSG, and the steam turbine, and means for cooling (wet or dry tower). Table A-2 in the Appendix presents examples of various arrangements – in addition to the most common arrangement of one combustion turbine/HRSG aligned with one steam turbine (1 x 1), the arrangement of two combustion turbines and HRSGs and one steam turbine (2 x 1) can generate greater power and extract higher thermal efficiency. This combined cycle arrangement is important in evaluating CO_2 emission rate.[35] EPA also recognized the operating point on the load curve – either near full nameplate capacity or at minimum load – drives the CO_2 rate.

EPA evaluated data from the 59 units operating since 2015 and determined the maximum 12-month rolling average of the population. The EPA reports 12-month rolling CO_2 emission rates ranging from 720 to 920 lbs/MWh, with an average of 810 lbs/MWh. EPA recognized that low-emitting units had features not applicable to the broad population of units, such as the Okeechobee Clean Energy Facility and the Dresden plant. These units' CO_2 emission rate averaged 770 lbs/MWh, enabled by a 2 x 1 arrangement and wet mechanical cooling towers, both of which reduce heat rate and CO_2 emission rate. Further, Okeechobee operates primarily at high load which further enables low CO_2 emission rates over a long averaging period (such as 12 months). Since most combined cycle units will likely be required to load follow during their lifetime, a limit based on high load operation is not broadly applicable to all operating cycles for most units covered by the NSPS.

Still, EPA singled out the Dresden plant as a reference unit, upon which EPA ultimately based its Phase 1 standard of 800 lb CO_2/MWh (for units larger than 2,000 MBtu/h):

> *.....the EPA has determined that the Dresden combined cycle EGU demonstrates that an emissions rate of 800 lb CO2/MWh-gross is achievable for all new large combined cycle EGUs with an acceptable compliance margin. Therefore, the EPA is finalizing a phase 1 standard of performance of 800 lb CO2/MWh-gross for large base load combustion turbines (i.e., those with a base load rating heat input greater than 2,000 MMBtu/h) based on the BSER of highly efficient combined cycle technology.*[36]

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[35] The 2 x1 arrangement increases thermal efficiency but is also enhances operating flexibility by providing for online power generation while one combustion turbine undergoes maintenance and repair. Operating in this mode reduces thermal efficiency and increases output-based CO_2 emission rate. The Subpart TTTTa baseload emission limit should not prevent operation in this mode.

[36] 89 Fed. Reg. at 39,947.

The Dresden Plant is an unusual choice as a reference. The two GE 7FA combustion turbines precede two Voght high pressure HRSGs, and a single GE steam turbine – a 2 x 1 array. The original design F-Class turbines have been upgraded with GE Advanced Gas Path hardware.[37] This hardware is reported by GE to increase the combustion turbine thermal efficiency by 1.2% with a further potential increase in steam side thermal efficiency pending higher turbine effluent gas flow and higher gas temperature.[38] Also, the facility employs wet mechanical cooling towers, which lower heat rate and CO_2 emission rate. Although the use of wet cooling towers is not prohibited, their water use can complicate permitting in many areas.

Using the 59 units, EPA developed a database reflecting the conventional 1x1 arrangement and dry cooling tower by "adjusting" CO_2 emission from units with multi-shaft arrangement (increasing CO_2 by 1%) and wet cooling (increasing CO_2 by 1.4%).[39] EPA also recognized that operation at low load elevates CO_2 emission rate. Consequently, EPA used historical data from each unit describing CO_2 emission rate as a function of load to project any increase in emission at 40% capacity. Figure 4-3 presents data from the Dresden Plant used for this purpose.[40]

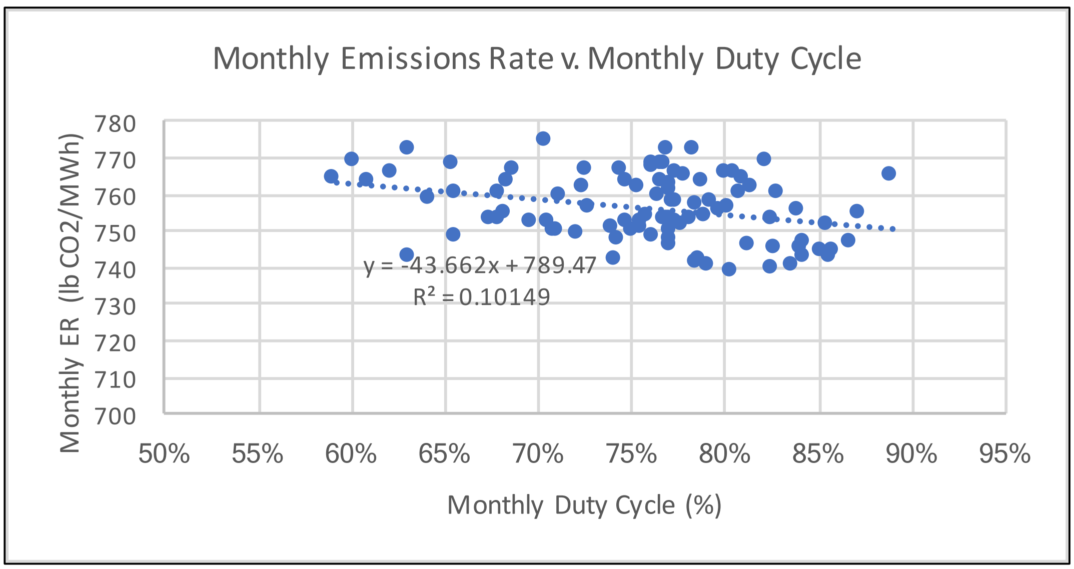

Figure 4-3. Example of Data Evaluation, Correlation Used for Dresden Plant Evaluation

There is no analysis in the 2024 rulemaking of whether the Dresden CO_2 emission performance is representative of what combined cycle units generally can achieve. First, Dresden is an F-Class based combined-cycle unit. It is not representative of smaller, E-Class and aeroderivative-based combined cycle units. In addition, the Dresden CO_2 data is not representative of the bulk

[37] AEP, personal communication, July, 2025.

[38] https://www.ge.com/news/press-releases/ges-advanced-gas-path-upgrades-generate-775-million-total-customer-value-annually

[39] CO_2 emissions from units with multi-shaft arrangements was elevated by 1% to translate to a 1 x 1 arrangement, and CO_2 from units with wet cooling tower was increased by 1.4% to account for a dry cooling tower.

[40] Adjustment factors to account low load (40% generating capacity) operation are derived for reference units in EPA_HQ-OAR-2023-0072-0060_attachment_4. See Worksheet Dresden 1A.

of operating F-Class and larger CT-based combined cycle units. This is evident from examining Figure 2-2, which presents the calculated CO_2 emission rate based on the suppliers' specification, and a "mean" adjustment of 12.5%. The CO_2 emissions in this figure for a 602-MW F-class combined cycle in 2 x 1 configuration is shown as 850 lbs/MWh. It should be noted that the value of 24% adjustment is implied by Figure 2-4 for the F-Class based population, approximating not the "mean" adjustment but the maximum. Also, Figure 2-4 shows a relatively high standard deviation of 171 lbs/MWh, implying approximately 6 units can emit at 751 lbs/MWh or less. This means the Dresden data resides in the lowest statistical cohort of F-Class combined cycle data.

Figure 4-4 depicts the data previously presented in Figure 3-4, but plotted as a function of capacity factor. The Dresden CO_2 emission rate of 771 lbs/MWh is called out on the figure for an annual capacity factor that averages 70% for the relevant operating years. As Figure 4-4 shows, there are approximately 10 units in the combined cycle population that emit CO_2 at a rate lower than Dresden; the vast majority of units in the database emit at higher rates. The increment provided by elevating the rate to 800 lbs/MWh does not significantly improve the margin for compliance for these units.

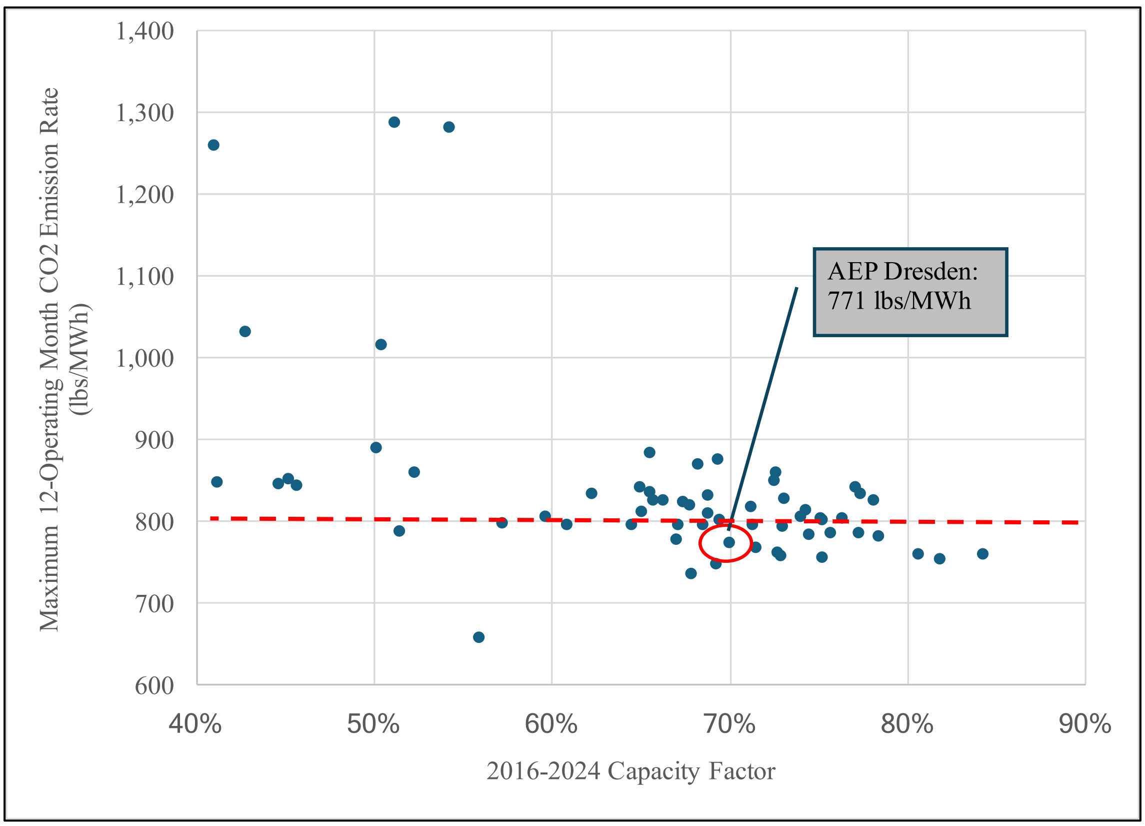

Figure 4-4. CO_2 Emissions from the Combined Cycle Population: Role of Dresden

EPA does not offer an analysis into the 2024 record as to why they determined any new combined-cycle unit ought to be able to achieve the CO_2 emission rate achieved by Dresden. As this study emphasizes, the 12-month rolling average efficiency (and, therefore, CO_2 emissions rate) of a combustion turbine is affected not just by the inherent efficiency of the unit, but also by operating conditions (i.e., elevation; average ambient temperature; unavoidable degradation; air inlet fouling; and condenser conditions) as well as operating duty (not just average capacity factor, but more importantly average duty factor; frequency of startup and shutdown; frequency and rate of load changes; etc.). Operating conditions are outside the control of the operator entirely. Operating duty is theoretically subject to operator control, though it is largely dictated by grid demand and constraints. EPA selected Dresden as representative, without analysis of whether Dresden itself would be able to meet the CO_2 emission rate EPA selected were Dresden located at a higher altitude, or operated at higher ambient temperature, or at a different duty (within the base load category). Nor did EPA analyze why the majority of operating combined cycle units in the database emitted CO_2 at a higher rate than Dresden. Without these analyses, there is no basis for concluding that any new unit should be able to meet the CO_2 rate that Dresden achieved under its own operating conditions and duty.

It is also clear that no combined-cycle unit with a base load rating less than 2,000 MBtu/h in the available database achieves the sliding-scale standard of 800 to 900 lb CO_2/MWh).

Conclusions

Simple Cycle. The 2024 Phase 1 output-based CO_2 emission performance standard for intermediate load turbines of 1,170 lbs/MWh for simple-cycle CTs operating at intermediate load is derived almost exclusively from aeroderivative design turbines, for which inlet turbine pressure ratio – among other factors unique to aeroderivative design – cannot be replicated on frame units. The ability to deliver inlet air pressure at a ratio of 45-to-1 (compared to ambient) that cannot be replicated on large frame engines due to a design limitation of compressors (per maximum blade tip speed). Such aeroderivative units are not representative of the larger frame-type units that could be deployed. Further, the three specific reference units represent an extreme edge of the thermal performance envelope for all simple-cycle CTs. Even within the aeroderivative models selected by EPA, not all units demonstrate compliance with the standard.

Combined Cycle. The combined cycle's 2024 Phase 1 CO_2 emission rate of 800 lbs/MWh (for units larger than 2,000 MBtu/h) is based on projection of thermal performance of a unit that is not representative of the turbine population. Without an analysis of why the vast majority of combined-cycle CTs in the database never met the selected standard, EPA cannot conclude any new unit should be able to meet the usually low CO_2 emission rate achieved by an outlier unit.

Section 5. Critique of Cost Evaluation: Simple, Combined Cycle LCOE Equivalency

The EPA's decision to select a 40% capacity factor as the threshold for the base load category is derived from a cost evaluation of the levelized cost of electricity (LCOE) for simple and combined cycle units.[41] In effect, EPA set the emissions standard for the base load subcategory (800-900 lb/MWh) to be achievable by combined-cycle CTs only; as a result, simple-cycle CTs, under the 2024 rule, are prohibited from operating at more than 40% capacity factor.

Section 5 critiques EPA's evaluation on several accounts. First, the analysis requires comparing performance and cost of simple and combined cycle units of identical generating capacity – for which a source does not exist in the available literature.[42] Thus, EPA elects to "create" four new reference cases, requiring up to four "adjustments" or "extrapolations" each of which introduces error. EPA does not account for these errors and the resulting uncertainty in its analysis. Second, for each of the four new reference cases, EPA selects a narrow range of input conditions that determine results (i.e. unit lifetime and natural gas price) which may not reflect future applications. Small changes to these inputs can substantially alter the results.

This section reviews EPA methodology and proposes an alternative approach. Moreover, regardless of the approach, small changes in assumptions yield significant changes in the LCOE analysis. This suggests that the deterministic LCOE analysis that EPA used to set the 40% capacity factor threshold for base load is not supported.

EPA Methodology

An overarching observation is that generating plant cost estimates are constantly evolving in response to the market. Capital cost estimates for both simple and combined cycle units have escalated in recent years, and may continue to do so pending supply chain issues. Generalized studies from entities such as the National Energy Technology Laboratory (NETL) and the Energy Information Administration (EIA) may not always accurately reflect the current economic climate, much less the economic climate in the next decade and beyond.

EPA references an NETL report that develops cost and performance data for a variety of natural gas-fired generating units.[43] These reference cases range from 50 MW aeroderivative turbines to several variants of combined cycle units with F-Class and H-Class turbines. The relevant

[41] Efficient Generation: Combustion Turbine Electric Generating Units Technical Support Document, Docket ID No. EPA-HQ-OAR—2023-0072, April 2024. At p. 31. Hereafter 2024 Efficient Generation TSD.

[42] Cost and Performance Baseline for Fossil Energy Plants, Volume 5: Natural Gas Electricity Generating Units for Flexible Operation, National Energy Technology Laboratory, May 2023.

[43] Ibid.

comparison is the LCOE for simple cycle versus combined cycle units at the same generating capacity.

The four generating capacities EPA selected for comparison are as follows:

- 100 MW. NETL provides the simple cycle design, with EPA creating the combined cycle version by "scaling" data from other sources.

- 50 MW. NETL results enable the extraction of a nominal 50 MW simple cycle design from the reference case. The combined cycle case is created by "scaling" cost and performance from reference units to extremely small scale.

- F-Class (375 MW). The NETL report provides the combined cycle reference case; the cost and performance for the CT in simple cycle is scaled.

- H-Class (560 MW). NETL provides the H-Class combined cycle reference; the cost and performance for the CT in simple cycle is scaled.

These four comparisons are developed as follows:

Aeroderivative Cases

The steps EPA cites to create 50 MW and 100 MW combined cycle units are as follows:

Define New HRSG/Steam Turbine Cost. EPA uses conventional "power-scaling scaling" laws to adopt cost for steam components from F-Class and H-Class units to the 50 and 100 MW capacity. The use of this method to scale cost by a factor of ten violates DOE/NETL standard practice, as advised in the *2013 Scaling Quality Guidelines* that power-law exponents be used with caution. [44] Specifically, DOE/NETL caution that "*…..there is a large percentage difference between the scaling parameters. This is particularly true for the major equipment items.* The use of this methodology to scale by more than a factor of 10 is beyond the conventional range.

Implement Cost "Deducts" to Account for Scope Differences. The HRSG and steam turbine costs for the F- and H-Class units exhibit features not typical of small aeroderivative-based combined cycle. Thus, capital costs must be reduced, as an auxiliary boiler (2.2%) is not required for fast-start, and the lower steam pressure HRSG and steam turbine (3.9% reduction) are also considered. A further cost "deduct" of 40% for the HRSG was adopted to account for lower heat throughput, as these smaller units use intercooling which reduces the heat removed.

To estimate fixed and variable operating and maintenance costs, EPA extrapolated those costs developed for the larger F-Class and H-Class units.

[44] Quality Guidelines for Energy Systems Studies, Capital Cost Scaling Methodology, DOE/NETL DOE/NETL DOE/NETL-341/013113, January 2013. At 18.

Each of these adjustments can introduce an error of 10% or more. Perhaps most significant is the use of a power-scaling law to translate capital cost from one generating capacity to another. There are two flaws in EPA's application. First, EPA uses the power-scaling law well outside the advised limit. The cost for steam-side equipment is scaled from the 375 MW F-class or 560 MW H-class units to 50 and 100 MW aeroderivative units. As noted in the 2013 DOE/NETL Scaling Guideline, the use of conventional power-law scaling methodology introduces significant risk when there is a large difference between the reference and the target capacity.[45]

Second, the scaling "exponent" of 0.6 represents conventional practice and does not necessarily represent the values relevant for thick-walled, high-pressure components.[46] The technical literature on cost scaling describes a wide range of exponents depending on equipment type. Specifically, a classic engineering treatment of cost evaluation states that most scaling exponents can range from 0.27 to 1;[47] and many "cluster" around 0.6 and it is convenient in certain cost-estimating actions to adopt "six-tenths" for the power law. The selection of a scaling exponent per this criterion is not a rigorous basis for a cost study with national policy implications. Regarding the use of the "sixth-tenth" exponent, Peters and Timmerhaus note:

> *the application of the 0.6 rule-of-thumb for most purchased equipment is an oversimplification of valuable cost concept since the actual values of the cost capacity factor vary from less than 0.2 to greater than 1.0 as shown in Table 5. Because of this, the 0.6 factor should only be used in absence of other information*.[48]

For power generation, the Electric Power Research Institute (EPRI) Technical Assessment Guide recommends scaling the cost of power generation equipment by using exponents that vary from 0.24 to 0.28.[49] Exponents of this value are appropriate for scaling the cost of entire power-generating facilities – including foundations, high-pressure steam components, and precision equipment such as steam turbines.

A major cost adjustment for which little basis is presented is the 40% reduction in HRSG costs due to the use of inter-stage cooling.

As an aside, comparison of 50 MW and 100 MW units is likely not relevant. As EPA explains, an owner of a 50 or 100 MW simple cycle will utilize this unit to meet different mandates in terms of ramp rate and would not consider a 100 MW combined cycle unit.

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[45] Ibid. At 18. There are limitations on the ranges that can accurately be addressed by the scaling approach. There can be step changes in pricing at certain equipment sizes that may not be captured by the scaling exponents. Care should be taken in applying the scaling factors when there is a large percentage difference between the scaling parameters. This is particularly true for the major equipment items.
[46] EPA notes "The rule of six-tenths is a generic approach to estimating economies of scale". See 2024 TSD, footnote 110.
[47] *Plant Design and Economics for Chemical Engineers, Fourth Edition*, Peters M.S. and Timmerhaus K.D. McGraw Hill International Editions, Chemical and Petroleum Engineering, 1991. See page 170, Table 5.
[48] Ibid. Page 169.
[49] EPRI Technical Assessment Guide, Electricity Supply – 1993, EPRI TR-102276-V1R7, Volume 1: Rev. 7. See page 8-11.

F-, H-Class Comparison

The NETL cases of CC1A-F and CC1A-H are combined cycle reference cases at 375 MW and 560 MW respectively. EPA extracts the simple cycle generating unit cost and performance and adjusts it to a comparable generating capacity. EPA employed the following steps.

Adjustment 1. "Subtract" the cost of components dedicated to the steam cycle and associated hardware. The result is a simple cycle cost for F- or H-Class unit.

Adjustment 2. EPA utilizes steam side costs from a 2009 World Bank Study, which projects steam cycle equipment costs derived from 1996 to 2003, to refine the combined cycle costs of F-Class and H-Class.[50] The reference chart on page 32 of the Technical Support Document[51] could not be identified in the source document. This step could introduce significant error.

Adjustment 3. EPA estimated fixed cost and the fixed and variable operating and maintenance costs for the new combined cycle unit by extrapolating the NETL reference cases by relative heat inputs between the NETL and new reference cases.

Every one of these adjustments and estimates relies on assumptions that can substantially influence the results, as well as engender a fair amount of uncertainty.[52] EPA then selected a 30-year unit lifetime and natural gas price of $4.43/MBtu to determine LCOE.

The projected capital cost for these new reference cases contains numerous uncertainties which should be considered in the significance of the conclusions. Every one of these adjustments and estimates relies on assumptions that can influence the results substantially and promote uncertainty. Table 5-1, extracted from the TSD, shows that – particularly at a 40% capacity factor – the difference in cost range is from "zero" to 2%, which is decidedly small in the context of the assumptions and adjustments.

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[50] *Study of Equipment Prices in the Power Sector*, Energy Sector Management Assistance Program, Technical Paper 122/09, January 2009. Hereafter 2009 Equipment Prices Study

[51] *Efficient Generation: Combustion Turbine Electric Generating Units Technical Support Document*, Docket ID No. EPA-HQ-OAR-2023-0072, April 2024.

[52] It should be noted the explanation of the steps executed by EPA as described by the *2024 Efficient Generation TSD* are not clear and do not portray an understanding of the EPA's actions. Specifically, the description presented does not describe how data from the *2009 Equipment Prices Study* are used in lieu of the cost available describing steam side components as presented in the F-Class and H-Class cases of the 2023 NETL study.

Table 5-1. Comparison of LCOE: EPA Manufactured Reference Cases

	Steady State LCOE ($/MWh)							
Capacity Factor (%)	F-Class Combined Cycle	F-Class Simple Cycle	H-Class Combined Cycle	H-Class Simple Cycle	100 MW Aeroderivative Combined Cycle	100 MW Aeroderivative Simple Cycle	50 MW Aeroderivative Combined Cycle	50 MW Aeroderivative Simple Cycle
5%	308	237	268	205	428	380	506	448
10%	166	136	146	119	229	207	267	242
20%	96	86	85	76	130	121	147	139
30%	72	69	65	62	96	92	107	104
40%	60	61	54	55	80	78	87	87
50%	53	56	48	50	70	69	75	77
60%	48	53	44	47	63	64	67	70
70%	45	50	41	45	58	59	62	65
80%	43	49	39	44	55	56	57	61

Alternative Approach

A 2024 EIA analysis[53] is a better reference study for this purpose. This 2024 study contains one reference case that can be used without adjustment; only one "case" needs to be created by extrapolating costs over a small range. EPA cites this 2024 EIA work but does not utilize it.

This EIA work (conducted by Sargent & Lundy) developed capital and operating costs for two reference cases employing an H-Class combustion turbine. A simple cycle design generating 419 MW at a heat rate of 8,873 Btu/kWh is represented by Case 4, with a Case 6 combined cycle generating 627 MW at a heat rate of 6,222 Btu/kWh (comprised of a 453 MW combustion turbine and 192 MW steam turbine). The Case 6 combined cycle design can be extrapolated from 627 MW to the Case 4 capacity of 419 MW, within the advised application of scaling laws.

The comparison of simple versus combined cycle units at approximately 450 MW reflects the present commercial marketplace. For example, among the combined cycle commercial offerings in Appendix A Tables A-1 and A-2 are Siemens simple and combined cycle units employing the SGT6-8000HL combustion turbine at comparable generating capacities. GE offers a simple and combined cycle unit using the GE HA.02 combustion turbine, generating 384 MW in simple cycle and 573 MW in combined cycle. These commercial offerings are well reflected by the reference cases cited by this study.

Table 5-2 presents two cases relevant for this analysis at 419 MW. The cost and performance characteristics for the EIA H-Class Case 4 and the adjusted Case 6 to match the 419 MW output are summarized. Capital costs are scaled as are fixed and variable O&M costs.

[53] Energy Information Agency, Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies, January 2024.

Table 5-2. Referenced Cases per Energy Information Administration Performance, Cost

Variable	**Case 4: SC, H-Class**	**Case 6: CC, H-Class**	**Case 6 Adjusted per Output**
Capacity, MW	419	627	419
Capital, $/kW)	838	921	
Scaling exponent: 0.6			1,082
Scaling exponent: 0.5			1,127
Heat Rate (Btu/kWh)	9142	6226	6226
Fixed O&M, $/kW-yr	6.87	16.46	20.14
Var O&M ($/MWh)	1.24	3.33	4.07

Table 5-2 demonstrates the uncertainty inherent in the input assumptions, by reporting capital scaled by using both EPA's selection a "0.6" exponent, and a value of "0.5" – a difference that reflects scaling for high pressure, thick walled components. Notably, the use of "0.5" versus "0.6" lowers the capital cost of the combined cycle from $1,127/kW to $1,082/kW – a 4% difference, which influences the outcome.

Figure 5-1 presents results of calculations reporting the LCOE (as $/MWh) from the EIA study. Three options are addressed: the 419 MW simple cycle (Case 4), the 627 MW combined cycle (Case 6), and an extrapolated "new" combined cycle unit of 419 MW combined cycle (extrapolated Case 6). The LCOE is presented as a function of capacity factor. Figure 5-1 results are presented for generating capacity, combined cycle capital cost, and natural gas price that differ very slightly from those employed by EPA. Specifically, these are slightly shorter lifetime (25 years), higher capital cost (resulting from the use of a 0.5 scaling factor), and a natural gas price ($4.00/MBtu). These represent small changes from EPA's input and are at least equally representative of future conditions.

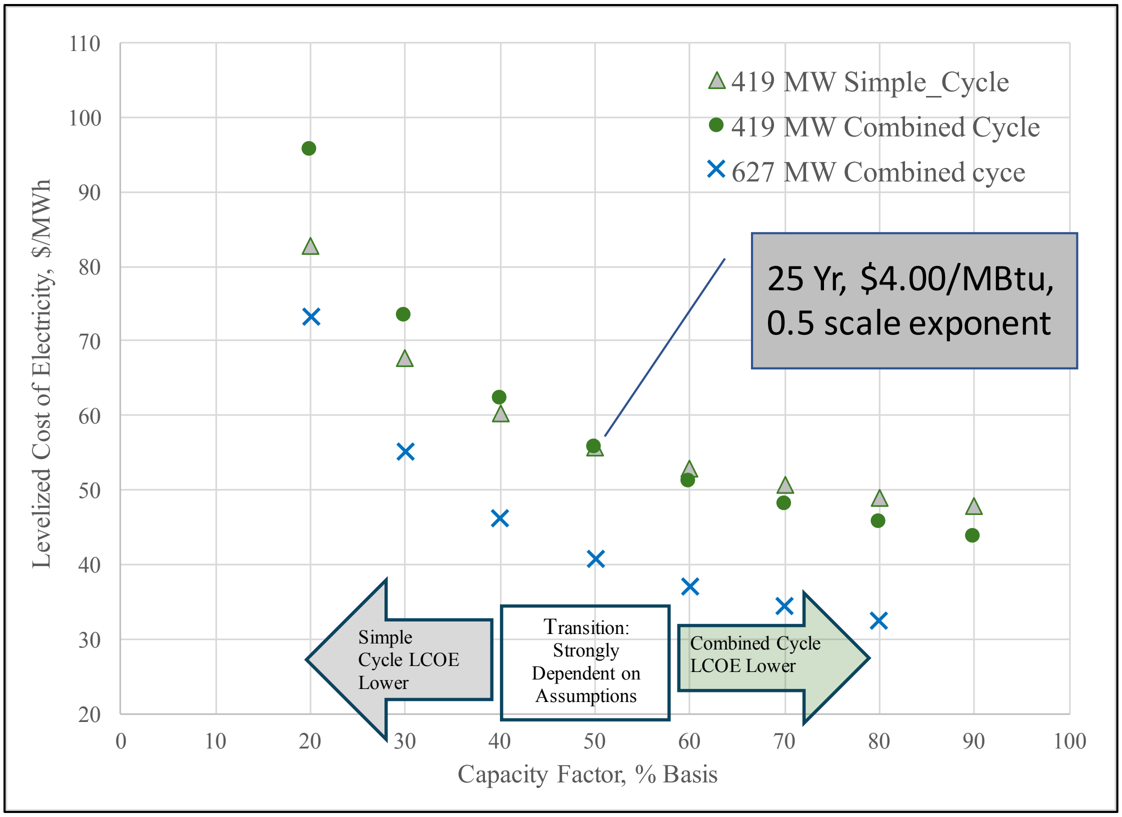

Figure 5-1. LCOE Equivalent per Adjusted EIA Analysis

Figure 5-1 shows that, using these factors, the LCOE from a simple cycle remains lower than that of a combined cycle up to a capacity factor of 52%.[54] The LCOE from the 627 MW (Case 6) combined cycle unit is significantly lower for the same 25-year lifetime and $4.00/MBtu natural gas costs, enabled by strong economies of scale.

Conclusions

EPA's conclusion that at 40% capacity factor the LCOE of a future combined cycle unit equates to that of simple cycle is highly uncertain, and based on assumptions that may not reflect future duty. EPA's use of an NETL study and the need to implement up to 4 "adjustments" to create new reference cases can introduce significant error, and bias the results to favor the combined cycle.

An alternative cost evaluation using a 2024 EIA study requires minor scaling of cost to derive comparable reference cases. The use of these EIA-derived reference cases and a 25-year unit life, natural gas cost of $4.00/MBtu, and a "scaling" exponent in agreement with literature for high-pressure components shows simple cycle LCOE lower than combined cycle up to 52% capacity factor.

[54] Exactly replicating EPA's inputs of a 30-year lifetime, natural gas cost of $4.43/MBtu, and the "default" scaling exponent shows simple cycle LCOE less than combined at 52% capacity factor.

Due to uncertainties introduced by EPA's methodology and the selection of key input values, using 40% capacity factor to define the base load segment of generation is not justified. The evaluation of simple cycle versus combined cycle LCOE described in this report highlights flaws in EPA's analysis. The methodology proposed by this report, not requiring the large number of extrapolations, is as reasonable as EPA's and justifiably supports a 52% threshold. Moreover, NSPS is forever. The economics of producing electricity could change. It may not be appropriate for EPA to mandate that simple-cycle CTs can never be used for base load operations (at whatever level EPA selects for this load subcategory).

Appendix A. Reference Supplier Combustion Turbine Data

Table A-1. Simple Cycle Units

	Turbine Supplier/Model	Output (MW)	Heat rate (Btu/kWh, LHV)
J-Class			
Mitsubishi	M501JAC	453	7755
H-Class			
Ansaldo	GT36	563	7935
Siemens	SGT6-8000HL	440	7898
GE	7HA.03	430	7884
GE	7HA.02	384	8009
Siemens	SGT6-8000H	328	8530
GE	7HA.01	290	8120
G-Class			
Mitsubishi	M501GAC	283	8531
F-Class			
Ansaldo	GT26	370	8322
Siemens	SGT6-5000F	260	8530
GE	7F.05	239	8871
GE	7F.04	201	8873
GE	6F.03	88	9277
E-Class			
Siemens	SGT6-2000E	119	9611
GE	7E.03	90	10107
Mitsubishi	M501DA	113	8930
Aeroderivative			
Mitsubishi	FT4000SwiftPac 140	144	8209
GE	LMS100 PA+	117	7702
Mitsubishi	FT4000SwiftPac 70	71	8232
Mitsubishi	FT4000SwiftPac 60	62	9281
GE	LM6000 DLE PF+	54	8277
GE	LM6000 SAC PG	54	8666

Table A-2. Combined Cycle Units

Class			Array	Output (MW)	Heat Rate (Btu/kWh, LHV)
J-Class	Mitsubishi	M501JAC	1 x 1	664	5332
			2 x 1	1332	5315
H-Class	Ansaldo	GT36	1 x 1	800	5451
			2 x 1	1605	5433
	Siemens	SGT6-8000HL		440	5416
	GE	7HA.03	1x1	648	5342
			2x1	1298	5332
		7HA.02	1 x 1	573	5381
			2 x 1	1148	5365
	Siemens	SGT6-8000H	1x1	465	5530
			2x1	960	5530
	GE	7HA.01	1x1	438	5481
			2x1	880	5453
G-Class	Mitsubishi	M501GAC	1x1	427	5640
			2x1	856	5652
F-Class	Ansaldo	GT26	1 x 1	540	5594
			2 x 1	1083	5575
	Siemens	SGT6-5000F	1 x 1	387	5725
			2 x 1	775	5715
	GE	7F.05	1 x 1	379	5667
			2 x 1	762	5640
		7F.04	1 x 1	309	5716
			2 x 1	602	5675
		6F.03	1x1	135	5998
			2x1	272	5994
E-Class	Siemens	SGT6-2000E	1x1	178	6354
			2x1	356	6354
	GE	7E.03	1x1	140	6514
			2x1	283	6454
	Mitsubishi	M501DA	1 x 1	167.4	6193
			2 x 1	336.2	6083
Aero-D	Mitsubishi	FT4000SwiftPac 140	1 x 1	180	6682
	GE	LMS100 PA+	1 x 1	137	6567
			2 x 1	247	6555
	Mitsubishi	FT4000SwiftPac 70	1 x 1	89.3	6734
	Mitsubishi	FT4000SwiftPac 60	2 x 1	85	6878
	GE	LM6000 DLE PF+	1 x 1	54	8277
	GE	LM6000 SAC PG	1 x 1	54	8666

Appendix B. Units Not in EPA Study

Table B-1. Units Excluded from EPA Data Base

plant_id	plant_name	Units	State	Cycle	In Service Date
3	Barry	1	AL	C	2023
56	Lowman Energy Center	1	AL	C	2023
136	Seminole (FL)	1	FL	C	2023
6061	R D Morrow	1	MS	C	2023
55460	Indeck Niles Energy Center	1	MI	C	2022
57185	Cricket Valley Energy	3	NY	C	2020
58001	Panda Temple Power Station	1	TX	C	2015
58478	LEPA Unit No. 1	1	LA	C	2016
59220	Wildcat Point Generation Facility	1	MD	C	2018
60356	South Field Energy	2	OH	C	2021
60903	Salem Harbor Power Development	2	MA	C	2018
60925	Montgomery County	1	TX	C	2021
60927	Lake Charles Power	1	LA	C	2020
61028	Hickory Run Energy Station	1	PA	C	2020
62192	Blue Water Energy Center	1	MI	C	2022
47	Colbert	3	AL	S	2023
141	Agua Fria	2	AZ	S	2022
492	South Plant	5	CO	S	2023
641	Gulf Clean Energy Center	4	FL	S	2021
1378	Paradise	3	KY	S	2023
3456	Newman	1	TX	S	2023
10350	Greenleaf 1	1	CA	S	2022
55129	Desert Basin	2	AZ	S	2022
56298	Roseville Energy Park	2	CA	S	2022
56350	Colorado Bend Energy Center	2	TX	S	2023
57943	Lonesome Creek Station	3	ND	S	2015
60387	Invenergy Nelson Expansion LLC	2	IL	S	2023
1	Astoria Station	1	SD	S	2021
61242	Tres Port Power, LLC	1	TX	S	2019
61966	Victoria Port Power II LLC	2	TX	S	2022
62548	SJRR Power LLC	2	TX	S	2022
63259	Delta Energy Park	1	MI	S	2022
63335	HO Clarke Generating	3	TX	S	2021
63688	Topaz Generating	10	TX	S	2021
64383	Braes Bayou Plant	8	TX	S	2022
65372	Mark One Power Station	6	TX	S	2022
65373	Brotman Power Station	6	TX	S	2023