July 8, 2024

VIA CERTIFIED AND ELECTRONIC MAIL

The Honorable Michael S. Regan, Administrator, EPA
Office of the Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Mail Code: 1101A
Washington, DC 20460

Re: EPA Final Rule – 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, Docket No: EPA-HQ-OAR-2023-0072, 89 Fed. Reg. 39798 (May 9, 2024).

Pursuant to Section 307(d)(7)(B) of the Clean Air Act,[1] the Environmental Defense Fund ("EDF") and Sierra Club ("Petitioners") respectfully petition the Environmental Protection Agency ("EPA") for reconsideration[2] and strengthening of its final rules ("Final Rule" or "Rule") adopting New Source Performance Standards and Emission Guidelines for greenhouse gas ("GHGs") emissions from new and existing fossil fuel-fired electric generating units ("EGUs").[3] This petition is timely filed within 60 days of the May 9, 2024 promulgation of the Rule. The purpose of this petition is to address issues of central relevance to the outcome of the final rule—which include issues that Petitioners did not have an opportunity to properly address during public comments and materials not available during that time—and to strengthen the standards for new gas-fired combustion turbines. Our objections are of "central relevance" to the outcome of this rule, 42 U.S.C. § 7607(d)(7)(B), because—consistent with EPA's interpretation of that term—they present "substantial support for the argument that the regulation should be revised." *Chesapeake Climate Action Network, et al. v. EPA*, 952 F.3d 310, 322 (D.C. Cir. 2020). Indeed, our objections go to one of the fundamental purposes of the Final Rule: to reduce GHG emissions from natural gas-fired EGUs.[4]

As explained herein, our petition seeks reconsideration primarily on the following issue: EPA's determination that the best system for emission reduction for new intermediate load gas-fired EGUs is simple cycle combustion turbines ("CTs") rather than natural gas combined cycle ("NGCC") generation technology. In making this determination, EPA did not present Petitioners with an adequate opportunity to review and respond to the documentary support for its rationale

---

[1] 42 U.S.C. § 7607(d)(7)(B).
[2] In the alternative, we submit this document as a petition for rulemaking pursuant to 5 U.S.C. § 553(e).
[3] 89 Fed. Reg. 39,798 (May 9, 2024)
[4] Although not all gas-fired EGUs are combustion turbines (i.e., some are stand-alone steam-generating boilers), all references to "EGUs" throughout this petition refer to either simple cycle or combined cycle combustion turbines.

during public comments. The agency also adopted new rationales and arguments in the final rule that directly contradict those presented at proposal. Furthermore, new research published since the public comment period closed support Petitioners' case that, apart from true peaking units, all gas-fired combustion should include a cost-effective, commonly available technology—a heat recovery steam generator ("HRSG") and steam turbine[5]—and thus operate as combined cycle EGUs. As our petition demonstrates, the agency has not justified its selection of simple cycle CTs as the best system of emission reduction ("BSER") for intermediate-load units, and available evidence strongly supports NGCCs as the proper technology for plants operating in this mode. Relatedly, we object to EPA's determination that intermediate-load performance corresponds with annual capacity factors as high as 20 percent, and also with the agency's decision not to include emission standards for units below 25 MW.

We note and appreciate that the EPA has opened a nonregulatory docket regarding potential regulatory options to reduce GHG emissions from *existing* combustion turbines[6], conducted a full day Workshop on these issues on May 17, 2024, and has committed to further rulemaking in this area. However, it is critical that the agency also control emissions from *new* gas-fired EGUs in accordance with the best system of emission reduction, and as we discuss throughout this petition, the agency left important opportunities on the table to reduce these sources' CO_2 in the new source rulemaking finalized in May 2024 without providing commenters a full opportunity to address arguments that were not supported with publicly available documentation or that were raised for the first time in that Final Rule.

Further, as explained below, the synergies between new and existing source regulations for gas-fired combustion turbines mean that a significant discrepancy between the stringency of the two rules encourages load-shifting from higher-regulated to lower-regulated sources, eroding the emission reduction potential of EPA's program. In addition, the existence of new and existing turbines housed at the same facility make adoption of combined cycle technology in lieu of CTs more practicable than if those categories are considered separately. For these reasons, we petition EPA to convene a proceeding for reconsideration of the Final Rule and afford a new opportunity for public comment on the issues raised below.

[5] For the sake of simplicity, throughout these comments, we refer to "HRSGs" to refer not just to an NGCC's steam generator, but to all the components of the unit's steam cycle, including its steam turbine and generator.
[6] Docket No. EPA–HQ–OAR–2024-0135.

Table of Contents

I. Introduction

Catastrophic climate change is no longer a mere possibility but is an outright certainty without major policy interventions to eliminate greenhouse gas emissions. The Intergovernmental Panel on Climate Change's (IPCC) most recent Assessment Report warns that

> [t]he cumulative scientific evidence is unequivocal: Climate change is a threat to human wellbeing and planetary health. Any further delay in concerted anticipatory global action on adaptation and mitigation will miss a brief and rapidly closing window of opportunity to secure a livable and sustainable future for all.[7]

And the window is brief indeed: the Mercator Research Institute on Global Commons and Climate Change calculates that, at currently global GHG emission rates, the world has merely five years before it expends its remaining budget of approximately 214 billion metric tons of CO_2 for staying within the critical threshold of 1.5°C of warming. [8] Above this threshold, many of the severest impacts of climate change will be irreversible.

Gas-fired EGUs—the vast majority of which are combustion turbines—are currently the single largest source of power sector electricity in the United States, providing about 40 percent of the country's total generation.[9] In 2023, gas-fired electricity released over 700 million metric tons of CO_2, constituting nearly half of sector-wide emissions and exceeding those of coal-fired units for the first time ever.[10] And under current projections, gas-fired generation capacity is expected to grow substantially: EIA's reference case in its *2023 Annual Energy Outlook* report shows over 210 GW in combined capacity additions of simple-cycle and combined-cycle units by 2050.[11] Any realistic path toward climate stabilization requires deep and immediate cuts in CO_2 from gas-fired electricity generation.

Recently, EPA adopted the Final Rule under Section 111 of the Clean Air Act, which, when fully implemented, will require meaningful reductions in CO_2 emissions from new baseload

---

[7] IPCC, *Climate Change 2022: Impacts, Adaptation and Vulnerability-- Working Group II Contribution to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change: Summary for Policymakers*, 35 (2022), https://www.ipcc.ch/report/ar6/wg2/downloads/report/IPCC_AR6_WGII_SummaryForPolicymakers.pdf.

[8] Mercator Research Institute on Global Commons and Climate Change, *Remaining Carbon Budget*, https://www.mcc-berlin.net/en/research/co2-budget.html (last visited June 27, 2024).

[9] Energy Info. Admin. ("EIA"), *Monthly Energy Review*, Table 11.6: Carbon Dioxide Emissions From Energy Consumption: Electric Power Sector (June 25, 2024), https://www.eia.gov/totalenergy/data/monthly/pdf/sec11_9.pdf.

[10] *Id.*

[11] EIA, *Annual Energy Outlook 2023*, Table 9. Electricity Generating Capacity: Reference Case, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2023&region=0-0&cases=ref2023&start=2021&end=2050&f=A&linechart=ref2023-d020623a.6-9-AEO2023~ref2023-d020623a.7-9-AEO2023&ctype=linechart&sid=ref2023-d020623a.6-9-AEO2023~ref2023-d020623a.7-9-AEO2023&sourcekey=0 (last visited Jun 27, 2024).

combustion turbines (as well as from existing coal-fired units).[12] However, in the same rulemaking, the agency chose not to require what the available evidence support as the BSER—combined-cycle generation technology—for intermediate load (i.e., load-following and seasonal baseload/load-following) natural gas fired turbines, which will constitute many or most of the new gas-fired units to be built in the coming years. In doing so, EPA has passed on an opportunity, and a statutory responsibility, to establish emission standards reflecting the best system of GHG emission reductions from those units that are achievable under the requirements of section 111.

Since the fundamental purpose of this rulemaking is to reduce GHG emissions from electric power plants, the agency's failure to require the best technology at intermediate-load units is of central relevance to the rulemaking. In their comments on the proposed rule, Petitioners Sierra Club and EDF[13] noted that EPA's proposal would create a substantial difference in rigor and cost between the largest and most frequently operated combustion turbines and the rest of the fleet. This gap would incentivize sources to comply with applicable standards by way of load-shifting from higher-capacity factor to lower-capacity factor units, which would erode the standards' emission reduction potential.

Petitioners' comments thus recommended that EPA designate NGCC rather than CT technology as the BSER for intermediate-load units, just as had already done for baseload units.[14] As explained, intermediate-load applications encompass not only units that run consistently throughout the year at levels above peaking but below baseload capacities, but also units that run for much or all of the time for a number of months out of the year and otherwise run little or not at all, which we refer to as seasonal baseload/load-following operations. Relatedly, our comments also urged EPA to reduce the capacity factor threshold for units qualifying for the low-load subcategory (i.e. "peaking units") from 20 percent on an annual basis to no more than 5 to 8 percent annually and 15 percent on a monthly basis.[15] Finally, we recommended that EPA must include standards for small CTs (i.e., those below 25 MW) rather than exempt them altogether.[16]

In the Final Rule, EPA retained simple-cycle generation technology as the BSER for intermediate-load-turbines rather than combined cycle generation. It also retained the 20 percent

[12] 89 Fed. Reg. 39,798 (May 9, 2024); 40 C.F.R. 60, Subpart TTTTa, Table 1.
[13] Comments of Sierra Club, Earthjustice, Conservation Law Foundation, and Appalachian Voices ("Sierra Club, et al. Comments"), EPA-HQ-OAR-2023-0072-0813, 7 (Aug. 8, 2023) https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0813/attachment_1.pdf; Comments of Environmental Defense Fund ("EDF Comments"), EPA-HQ-OAR-2023-0072-0764, 32 n.175 (Aug. 8, 2023), https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0764/attachment_1.pdf (incorporating by reference Sections III.A through III.D of Sierra Club, et al. Comments). These sections are included as Attachment 1 to this Petition.
[14] *Id.* at Section III.A.
[15] *Id.* at Section III.B.
[16] *Id.* at Section III.D. Our comments also raised many other issues, including a proposed an improved methodology that the EPA could use to calculate the baseline emission reduction rates for all affected sources at *id.*, section III.C. Those we discuss in this petition are the focus of our request for reconsideration.

annual capacity factor threshold separating the low-load from intermediate-load subcategories, and declined to include standards for units under 25 MW, regardless of how many such EGUs might be co-located in a single facility and thus function as a larger power plant. To justify these decisions in the Final Rule, EPA either offered new explanations that were not provided in the proposed rule or reiterated arguments that were included in the proposal but not accompanied by documentation that Petitioners had an opportunity to address. Moreover, after the close of the comment period, the Energy Information Administration published a 2024 update to its *Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies* report,[17] which reinforces the basic points included in Petitioners' comments and which we did not have an opportunity to present to EPA. Thus, because it was impracticable or impossible for petitioners to raise the points included in this Petition, and because they go to issues of central relevance, reconsideration is required. 42 U.S.C. § 7607(d)(7)(B).

II. Petitioners Did Not Have an Adequate Opportunity to Comment on the Issues Raised in this Petition.

Under section 307(d)(7)(B)'s "impracticability" standard, reconsideration in this case is necessary for at least seven reasons. ***First*****,** in proposed rule, EPA offered just two sentences to justify its decision to designate simple cycle combustion technology as the BSER for intermediate-load combustion turbines:

> The EPA considered but is not proposing combined cycle unit design for combustion turbines in the intermediate subcategory because the capital cost of a combined cycle EGU is approximately 250 percent that of a comparable-sized simple cycle EGU and because the amount of GHG reductions that could be achieved by operating combined cycle EGUs as intermediate load EGUs is unclear. Furthermore, intermediate load combustion turbines start and stop so frequently that there might not be sufficient periods of continuous operation where the HRSG would have sufficient time to generate steam to operate the steam turbine enough to significantly lower the emissions rate of the EGU.

EPA has in the Final Rule dropped this reliance on alleged capital cost differentials as a basis for selecting simple cycle technology as the BSER for intermediate-load units. Instead, the agency now makes no reference to the 250 percent figure, and has shifted its focus away from capital costs almost entirely in favor of a different financial metric: the levelized cost of electricity ("LCOE"), which takes into account capital costs, fixed and variable non-fuel operation and maintenance costs, and fuel costs. *See* 89 Fed. Reg. at 39,911. Unlike capital costs, which express the financial resources needed to building *generation capacity* (i.e., dollars per megawatt), LCOE describes the total costs associated with each *unit of energy production* (i.e., dollars per megawatt-hour). This is a major analytic shift, and the LCOE discussion comparing simple and combined cycle units that was provided along with the Final Rule—which are included in the Technical Support Document titled *Efficient Generation: Combustion Turbine*

---

[17] EIA, *Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies* (Jan. 2024), https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

Electric Generating Units ("Efficient Generation TSD")[18] and accompanying materials—was not included in the version of this TSD that was published at proposal.[19] The agency's change in rationale, and Petitioners' lack of opportunity to respond to it or to review the agency's analysis and documentation, require reconsideration.

Even then, the nature of EPA's reliance on LCOE (as opposed to capital costs) is unclear: it no longer asserts that CTs are, as a general matter, less expensive than NGCCs across-the-board, but instead indicates that LCOEs are generally lower for CTs than NGCCs at annual capacity factors below approximately 40 percent annual capacity factor, without considering the concomitant environmental impacts. *Id.* This is an entirely different financial argument from the one it presented in the proposed rule, which reflected a categorical statement about compliance costs. Again, this sudden shift in rationale obligates EPA to provide Petitioners an opportunity to address its new reasoning through a reconsideration process.

Moreover, with respect to the 250 percent figure from the proposal, EPA provided commenters with no access to any documentation it may have relied on in of that assertion, which it cited as the primary reason for rejecting NGCC technology as the BSER for those units. Particularly given that this statistic is inconsistent with the multiple cost studies that Petitioners cited in their comments—which showed that NGCCs are on average *cheaper* than CTs that can serve the same function—the lack of access to EPA's record support for this rationale made it impracticable for us to properly address the agency's claim.

Second, EPA's evaluation of fast-start NGCC capabilities changed considerably in the Final Rule, which included claims that directly contradict assertions made in the agency's own Efficient Generation TSD mentioned above, versions of which were included in both the proposed rule[20] and Final Rule.[21] Citing multiple sources,[22] that document explains that

> [s]everal combustion turbine manufacturers market complete combined cycle

---

[18] EPA, *Efficient Generation: Combustion Turbine Electric Generating Units—Technical Support Document* ("2024 Efficient Generation TSD"), Dkt. No. EPA-HQ-OAR-2023-0072-9100, 31-36 (Apr. 2024), https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-9100/content.pdf.

[19] EPA, *Efficient Generation: Combustion Turbine Electric Generating Units—Technical Support Document* ("2023 Efficient Generation TSD"), Dkt. No. EPA-HQ-OAR-2023-0072-0060, 25–26 (May 2023), https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0060/content.pdf.

[20] 2023 Efficient Generation TSD at 25-26.

[21] 2024 Efficient Generation TSD at 28-30.

[22] *Id.* at 28 n. 98-100 (citing Gulen, S.C., *Gas Turbine Combined Cycle Fast Start: The Physics Behind the Concept* (2013), http://www.mcilvainecompany.com/Decision_Tree/subscriber/Tree/DescriptionTextLinks/Physics.pdfl; Power Magazine, *Fast-Start HRSG Life-Cycle Optimization* (June 1, 2013), https://www.powermag.com/fast-start-hrsg-life-cycle; and Eddington, et al., *Fast start combined cycles: how fast is fast?* (2017), https://www.powereng.com/emissions/fast-start-combined-cycles-how-fast-is-fast/#gref).

> systems that can ramp up to full load from a cold start in less than an hour, depending on unit-specific factors. Advanced combustion turbines, when isolated from the HRSG and steam turbine, can reach full load at full speed as a simple cycle (*i.e.*, Brayton) unit in less than 20 minutes. When adhering to some of the following fast-start techniques, the HRSG, steam turbine, and balance of plant equipment can reach safe operating temperatures and pressures and begin generating additional electricity within 30 to 45 minutes of ignition of the combustion turbine.

In the Final Rule preamble, however, EPA asserts that fast-start NGCCs can only reach full load operations within 30 minutes upon a *hot* start, and that *cold* starts require 120 minutes for such units. The agency does not reconcile the discrepancy with the section of its TSD that associates the 30-45-minute figure with *cold* starts. Petitioners therefore require a reconsideration proceeding to properly evaluate and respond to EPA's assertion, which is central to its rejection of NGCC technology as the BSER for intermediate-load units.

Third, approximately five months after the comment period closed, in January 2024, EIA published its latest version of the report titled *Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies*, prepared by Sargent & Lundy.[23] Petitioners relied on the 2020 version of this report in its comments urging the agency to adopt NGCC as the best system for intermediate-load units, and the 2024 version provides even clearer evidence in favor of our argument. Namely, it presents capital cost figures that are *lower* than in the 2020 report for NGCCs units ($868/$921 in 2024 versus $958/$1084 in 2020) and that are *higher* for simple-cycle units ($1606/$836 in 2024 versus $1175/$713 in 2020).[24] Because this study was published after the close of the comment period, it was clearly not practicable for petitioners to bring it to EPA's attention during that time. To the extent that EPA relies directly on capital cost differentials between NGCCs and CTs in the Final Rule in its BSER determination for intermediate-load units, this report is undoubtedly relevant to EPA's decision. To the extent that EPA appears to have abandoned its capital cost assertions from the proposal, that fact act alone merits reconsideration (as discussed above), but in any event, capital costs are crucial component of LCOE—which the agency *did* consider in the Final Rule—and so under all circumstances, this report is centrally relevant to EPA's BSER selection for the units in question. Reconsideration is this necessary based on EIA's recently published study, in addition to the reasons noted above.

Fourth, EPA did not afford the public an opportunity to review its evidentiary material supporting the claim that "the amount of GHG reductions that could be achieved by operating combined cycle EGUs as intermediate load EGUs is unclear." EPA's own Clean Air Markets Program Database (CAMPD) provides hourly, daily, monthly, quarterly, and yearly emissions and generation data for the entire electric power sector, and allows users to compare emission

---

[23] EIA, *supra* n. 17.

[24] *Id.* at Table 1-2: Cost and Performance Summary Table; EIA, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies)*, Table 2: Cost and Performance Summary Table, https://www.eia.gov/analysis/studies/powerplants/capitalcost/archive/2020/pdf/capital_cost_AEO2020.pdf.

rates of combined cycle and simple cycle turbines operating at similar frequencies. As discussed below in Section III.c, CAMPD data suggest that simple-cycle turbines emit approximately 18.3 percent more CO_2 per megawatt-hour than NGCCs when operating at frequencies consistent with intermediate-load application. The agency's assertion that the comparative emissions performance between NGCCs and CTs is "unclear" when operating in intermediate-load applications suggests that it possesses some other data or materials that contradict its own CAMPD results. Petitioners rebutted EPA's unsupported assertion in comments, and EPA has yet to provide relevant data on this point Final Rule. Reconsideration is thus warranted on this issue as well.

Fifth**,** the agency similarly declined to provide access to materials it relied on in support of its claim that intermediate load units "start and stop so frequently" as to erase the efficiency improvements of operating an HRSG. This assertion misapprehends the basic function of intermediate-load units, which typically start and stop once per day, generally running from mid-morning until evening and then ramping down or turning off at night. Petitioners rebutted EPA's unsupported assertion in comments, and again, the agency does not support its assertion in the Final Rule with clear data. To the extent that EPA has evidence that indicates that intermediate-load application has significantly changed or expected to change in the future such that these units turn on and off "so frequently" as to vitiate the benefits of an HRSG, it did not make that material public. Again, this omission requires a reconsideration procedure.

Sixth, reconsideration is also warranted for the related issue of where EPA set the threshold separating low-load from intermediate-load units. In our comments, Petitioners explained that most authorities define peaking operations as consistent with no more than 10 percent annual capacity factors, and we urged EPA to adopt a threshold separating peaking from intermediate-load operations at no more than 5-8 percent on an annual basis and (to account for seasonal load-following/baseload operations) 15 percent monthly. In retaining the 20 percent threshold, EPA asserted that this represents the level of operations for which "most simple cycle combustion turbines perform at a consistent level of efficiency and GHG emission performance," and that it "would be difficult to establish a reasonable output-based standard of performance" for turbines below this threshold. 89 Fed. Reg. at 39,912-13.

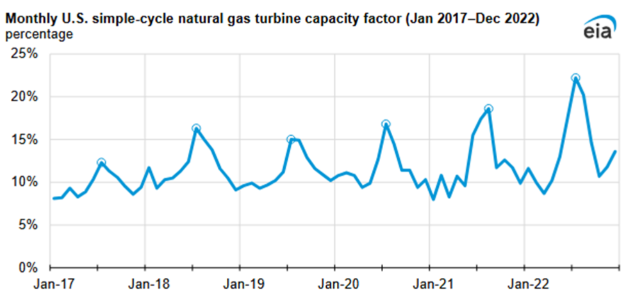
Yet this rationale is premised on what simple-cycle CTs are capable of achieving: it ignores the possibility that fast-start NGCCs are fully appropriate for operations that exceed true peaking applications (i.e., 5-8 percent annual and 15 percent monthly capacity factors), and may well be subject to an output-based standard below the 20 percent threshold. Thus, for the same reasons discussed above with regard to the proper BSER for intermediate-load units, the agency did not provide adequate documentation to allow for full comment on the 20 percent threshold.

Seventh and finally, in both the proposed rule and Final Rule, EPA provided *no* justification for excluding all units below 25 MW from the rule's scope. In response to our comment that such units often run frequently, are regularly co-located in singe large facilities, and can emit substantial amounts of CO_2, and should thus be subject to standards, the agency simply stated, rather tautologically, that it "did not propose and is not finalizing emission standard for electric generating units selling less than 25 MW to the grid at this time."[25] Petitioners cannot properly respond to a regulatory decision that EPA did not explain, and reconsideration is therefore appropriate on this issue as well.

III. In Reconsidering the Final Rule, EPA Must Establish Combined Cycle Technology as the BSER for New Intermediate-Load Combustion Turbines.

We respectfully offer the following to inform EPA's corrective action in establishing a standard based on combined-cycle technology for the intermediate load subcategory. As the planet continues to experience unprecedented challenges associated with climate change the use of high-emitting simple combustion turbines (and the associated upstream methane leaks from natural gas production, processing, transmission and storage) continues to increase, peaking at twice the levels of five years prior.

Fig. 1: Monthly Simple Cycle Gas Turbine Capacity Factor (Jan. 2017-Dec 2022)[26]



The potential menu of options for reducing emissions from the large number of existing small and mid-sized intermediate-load units is necessarily a subset of what is available to reduce emissions of new units in the same categories. Relevant here, they include the following:

- Designating combined cycle technology as the BSER for intermediate-load EGUs and establishing an emission rate for these sources that reflects the performance of that technology.
- Setting the threshold for the low-load subcategory at a level that reflects true peaking applications—that is, an annual capacity factor of no more than 5 to 8 percent and a monthly capacity factors of 15 percent.
- Establishing standards of performance for *all* units that provide electricity to the grid; or, at a minimum, establishing basing the small-turbine exemption on a facility-wide basis rather than a unit basis (i.e., limit capacity factor for combustion turbines at facilities

[25] EPA, *Response to Comments: Chapter 7- Standards for New Gas-Fired Combustion Turbines*, Doc. No. EPA-HQ-OAR-2023-0072-8914, 21 (Apr. 2024), https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-8914/attachment_7.pdf.
[26] EIA, *U.S. simple-cycle natural gas turbines operated at record highs in summer 2022*, Today in Energy (Mar. 1, 2023), https://www.eia.gov/todayinenergy/detail.php?id=55680.

that, for example, are comprised of eight 10 MW peaking units).[27]

There are other emission reduction methods that are applicable to combustion turbines, including limitations on inefficient duct-burning, aggressive heat rate improvements, and the integration of renewable generation or battery storage capacity into the unit design, which Petitioners have discussed elsewhere. For this petition, however, we focus on items listed above. With an appropriate implementation schedule, these measures are feasible for both new and existing combustion turbines and well within cost-effectiveness range that is below EPA's current values for the social cost of carbon.[28] Accordingly, EPA should reconsider application of these measures to new combustion turbines even as it considers whether to require them at existing units.

In this petition, we focus primarily on the first bullet: EPA's failure to designate combine cycle technology as the BSER for intermediate load turbines. Our comments submitted in August of last year provide our central basis for this argument,[29] which we summarize in part here to provide proper context for this Petition.

a. Efficient fast-start NGCCs are available to meet all intermediate-load applications.

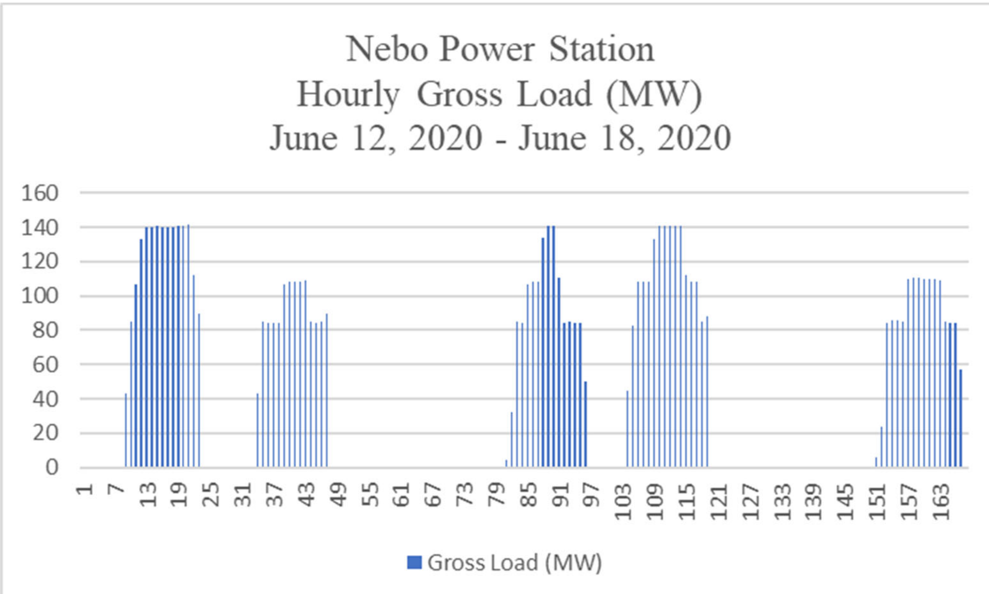
Much of the existing combined cycle gas turbine fleet is now 20 or more years old and will soon reach a time where substantial retrofit or replacement with the most advanced new "fast-start" NGCCs will likely occur for a substantial number of units. These fast-start NGCCs initially fire the combustion turbine and quickly bring the HRSG on line. Accordingly, they can respond to rapid changes in demand while emitting far less CO_2 than the simple cycle CTs of two or three decades ago. Similarly, inlet cooling at operating units can quickly increase output by 10 percent or more of the rated output of larger NGCCs and thereby minimize the need to operate simple cycle peaking units. Weather and demand forecasting have also improved significantly, minimizing the need for "10-minute cold start" simple cycle turbines.

In fact, even NGCCs installed two decades ago—which are far less efficient than today's best units—are still capable of ramping up quickly enough to meet intermediate-load demands. For instance, the Nebo Power Station in Payson, Utah is a 140 MW combined cycle plant that commenced commercial operation on June 17, 2004.[30] It consists of a 65 MW gas turbine and a

[27] Section 111(a)(2) defines a stationary source to include any "facility" that emits or may emit any air pollutant. 42 U.S.C. § 7412(a)(2),(a)(3).
[28] *See* EPA, *Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, 154 (Nov. 2023), https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf (establishing the median value at a 2.0% discount rate for the social cost of carbon at $208/MT CO_2 for 2024; by 2050, this figure increases to $308/MT CO_2).
[29] *See* Sierra Club, et al. Comments at Sections III.A and B; EDF Comments at 32 n.175 (incorporating by reference Sections III.A through III.D of Sierra Club, et al. Comments).
[30] All data that we cite regarding Nebo we acquired through a query to EPA's Clean Air Markets Program Database. EPA, *Clean Air Markets Program Data*, Custom Data Download https://campd.epa.gov/data/custom-data-download (last visited Aug. 2, 2023). All subsequent references to data retrieved from EPA's CAMPD will be cited as "CAMPD query."

75 MW steam turbine and has an SCR unit for NOx control. As demonstrated below, even after 16 years of operation, this unit had no difficulty ramping up and down in a manner consistent with intermediate-load operations over the course of a representative one-week period in June 2020:

<u>Fig. 2: Representative Hourly Gross Load of Nebo Power Station</u>



During this period, Nebo's emission rate was 872 lb/MWh-gross well within any conceivable emission rate EPA might establish for these units. A brand new unit equipped with the most state-of-the-art fast-start generation technology would show superior performance (and faster ramp times) still. In addition, operators may elect to employ the same fast-start and ramp-rate NGCCs that they otherwise would and, in rare instances in which an extremely short startup time[31] is required and the HRSG is not yet available, employ a bypass duct to operate the unit in simple cycle mode, as discussed in EPA's TSD.[32] While this is a suboptimal practice from both an economic and environmental standpoint, it can serve as a stop-gap for NGCCs in moments where very fast ramp-ups are required. Because EPA's emission rates are based on a rolling annual average, they provide a sufficient compliance margin to permit such infrequent and short-duration events without causing an exceedance. Further, the technology has advanced, through the use of exhaust stack dampers and revised startup routines, to allow the HRSG to remain "warm" and available on short notice.[33] The availability of these units fully address any concerns

[31] As mentioned in the previous section, EPA's own TSD asserts that the best fast-start NGCCs can operate the HRSG and steam turbine within 30 to 45 minutes of a "cold-start" firing the combustion turbine, whereas simple cycle CTs can achieve startup within a matter of minutes. 2024 Efficient Generation TSD at 28-30.
[32] *Id.* at 28-29.
[33] *See id.* at 25-26. *See also, e.g.*, Modern Power Systems, *Flexibility – the new battleground*, https://www.modernpowersystems.com/news/newsflexibility-the-new-battleground/ (last visited Aug. 6, 2023); John Gülen, *Gas Turbine Combined Cycle Fast Start: The Physics Behind the*

EPA has expressed about the frequency and spend of starts and stops at intermediate-load units.

b. Abundant cost analysis indicates that NGCC rather than CT units represent the proper selection of BSER for the intermediate-load subcategory.

As noted previously, EPA did not provide or cite any data, studies, or any analyses in support of its claim at proposal that the capital cost of a combined cycle EGU is 250 percent that of a comparably-sized CT or why that figure, independent of the emission reductions, is relevant to its selection of the BSER. Capital costs represent only one component of the cost of producing energy. EPA appears to have realized this in the Final Rule, abandoning its capital cost assertions and instead referring to comparative LCOE figures for NGCCs and CTs. Indeed, as discussed in this shift in the final rule is one of our bases for seeking reconsideration: Petitioners tailored their comments to focus on capital cost considerations, directly responding to EPA's proposed rationale, and had no opportunity to review or critique the agency's approach to LCOE.

At the outset of this section, it is critical to note that—contrary to arguments raised by certain industry parties and their supporters—section 111 does *not* require EPA to engage in any one particular kind of cost analysis in supporting its BSER determination. Rather, as the D.C. Circuit has long held, the statute prohibits EPA from adopting standards that would impose compliance costs that are "excessive," *Sierra Club v. Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981), "unreasonable," *id.*, or "exorbitant." *Lignite Energy Council v. EPA*, 198 F3d 930, 933 (D.C. Cir. 1999). In other words, the costs of the BSER must not be "greater than the industry could bear and survive," or beyond the ability of the industry to "adjust itself in a healthy economic fashion to the . . . the standards prescribed." *Portland Cement Ass'n v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975). But the statute does not bind the agency to any specific approach, metric, or economic test when determining whether costs are reasonable. *See, e.g.*, EPA Opp. To Mot. to Stay Final Rule, No. 24-1054 (and consolidated cases), *State of Texas, et al. v. EPA* (June 11, 2024) ("Section 7411 does not require formal cost-benefit analysis.").

Even in the context of a single section 111 rulemaking, EPA may rely on a number of different approaches to evaluate costs. For instance, in finalizing recent methane standards and emission guidelines for oil and gas equipment, the agency evaluated the rule's individual requirements on a cost-per-ton-abated basis, and also considered the rule's capital compliance costs as a ratio of the industry's total capital expenditures, as well as its annualized compliance costs as a ration of the industry's total estimated revenues. 89 Fed. Reg. 16,820, 16,864-67 (Mar. 8, 2024). According to all three metrics, EPA found the methane rule reasonable.

In raising the issue of EPA's shift from discussing the relative capital costs of CTs vs. NGCCs in intermediate-load operations in the proposal to a discussion of LCOE figures in the Final Rule, Petitioners do not imply that section 111 favors or requires one or the other of these indicators.

Concept, POWER ENGINEERING, June 12, 2013, https://www.power-eng.com/coal/gas-turbine-combined-cycle-fast-start-the-physics-behind-the-con/#gref; Siemens Energy, *From Base to Cycling Operation: Innovative Operational Concepts for CCPPs* (presentation delivered to Power-Gen Europe 2015 in Amsterdam, Netherlands, June 11–15, 2015), https://assets.siemens-energy.com/siemens/assets/api/uuid:0cb3c09d-3464-4d29-8cfe-055b7b5dee32/t6s2p2-powergeneurope2015-base-to-cycling.pdf, included as Exhibit 1.

Rather, we raise this distinction because we had no opportunity to address the agency's LCOE analysis in our comments, and thus seek reconsideration to do so here. Moreover, although we assert below that EPA's LCOE statistics for intermediate-load NGCCs and CT s favor the former technology because its monetized CO2 benefits relative to CTs outweigh any additional costs, we do not imply that this outcome would be required to support our position here. Rather, this fact simply bolsters the case for NGCC as the best system for the intermediate-load subcategory, which is already self-evident from industry's current practice. Indeed, not only can the industry "adjust itself in a healthy economic fashion" to relying on NGCCs for intermediate-load needs, Portland Cement, 513 F.2d at 508, it largely does so now: the majority of intermediate-load generation is currently provided by NGCCs,[34] whereas (according to EPA's own data) two-third of CTs operate at annual capacity factors below 20 percent and four-fifths operate at factors below 25 percent. 89 Fed. Reg. at 39,912.

With regard to the substance of EPA's LCOE discussion in the Final Rule, we have identified notable vulnerabilities in the agency's approach. First, there appears to be no sensitivity analysis of natural gas prices, which can fluctuate significantly and may well be higher in coming years than EPA anticipates. Second, EPA relied exclusively on data from the National Energy Technology Laboratory (NETL) to calculate LCOE values for combustion turbines. We do not cast aspersions on NETL's figures, but instead point out that a more robust data set, reviewing a range of sources, is critical: as discussed below, our own Comments reviewed four different studies to produce capital cost estimates for NGCCs and CTs, and EPA should perform a similarly rigorous and variegated study. In particular, it should account for EIA's 2024 capital cost study, which is the most recent analysis to be published.

The most problematic aspect of EPA's analysis is the way in which it relied on the LCOE figures it arrived at. The agency appears to justify its decision to establish CTs as the BSER for intermediate-load units based on its finding that NGCCs have a lower LCOE near or at 40 percent annual capacity factors and above, and that CTs have a lower LCOE below these levels. EPA writes in the Final Rule preamble:

> Based on an adjusted model plant comparison, combined cycle EGUs have a lower LCOE at capacity factors above approximately 40 percent compared to simple cycle EGUs operating at the same capacity factors. This supports the final base load fixed electric sales threshold of 40 percent for simple cycle turbines because it would be cost-effective for owners/operators of simple cycle turbines to add heat recovery if they elected to operate at higher capacity factors as a base load unit.

[34] A CAMPD inquiry shows that of all combustion turbines operating between 1,000 and 4,000 hours in 2023, NGCCs provided approximately 55 percent of the generation; for those operating between 1,000 and 4,500 hours, NGCCs provided over 64 percent of the generation; and for those operating between 1,000 and 5,000 hours, NGCCS provided over 71 percent of the generation. Note that although 4,000-5,000 hours represent approximately 45-57% of hours in a twelve-month period, the fact that combustion turbines often run at less than full load indicate that units meeting these operational hours will, in most cases, fall below EPA's 40 percent annual capacity factor threshold for baseload units.

89 Fed. Reg. 39,911. In the 2024 Efficient Generation TSD, it summarizes this conclusion as follows: “Based on this analysis, there are no compliance costs for using a combined cycle technology, compared to a simple cycle technology, capacity factors of approximately 40% or higher.”[35]

In other words, EPA apparently has determined for the purposes of this particular regulatory decision that the selection of one control technology as opposed to another is reasonable so long as it imposes no incremental compliance costs on the operator. Of course, this is not how section 111 operates, nor is it how EPA has treated other BSER determinations in the Final Rule. Compliance costs standing alone—whether capital costs or LCOE—are not determinative of cost-effectiveness. Rather, this calculation evaluates those costs *against the emission reduction benefits a control technology would achieve*. While we reiterate that this particular metric is not necessarily required under section 111, nor should be seen as exclusive of other analytic approaches, the agency must not base its BSER determination on LCOE differences alone, but must also consider the environmental impacts of its decision.

In this regard, our analysis indicates that even based on EPA’s LCOE data, combined-cycle units would be the appropriate selection of BSER for intermediate load units. In Figure 11 of the 2024 Efficient Generation TSD, EPA presents LCOE estimates for four different NGCC-CT points of comparison (F-Frame, H-Frame, 100 MW aeroderivative, and 50 MW aeroderivative) at seven different capacity factors of 5, 10, 20, 30, 40, 50, 60, 70, and 80 percent.[36] At the 20 percent line, the table shows the NGCC model plant with an LCOE that is $8-10 higher than for CTs, with declining differentials at higher capacity factors. To convert these differentials into a cost-per-ton-of-CO_2 value, we used a conservative emission rate differential of 1170 lb/MWh for NGCCs and 1307 lb/MWh. These figures represent the results of a CAMPD data query providing the relative emission rates of NGCCs and CTs that operated between 1,000 and 2,000 hours in 2023.

Based on these assumptions, our calculations showed that at a 20 percent capacity factor, the relative compliance costs of using NGCC rather than CT options would range from approximately $129 to $161/ton, well within EPA’s estimates of the social cost of carbon. For 30% capacity factors, where EPA’s table shows an LCOE differential of $3-4/ton, the compliance costs are even lower, on the order of $48-64. Thus, in the range that EPA has defined as intermediate-load and using the agency’s own data, NGCC units should still be the proper selection for the BSER. And even for capacity factors below this—for instance, above 5-8 percent annually and 15 percent monthly, a more complete range of capital cost and natural gas assumptions, as well as economies of scale for units of larger capacity, may well favor NGCC as the BSER as well. The fact is, Petitioners did not have an opportunity to even review this LCOE discussion, let alone conduct a full analysis on it, at proposal. A reconsideration period is therefore critical to allow for such a review and analysis.

In fact, simply considering capital cost values alone—as EPA did at proposal—reconsideration is appropriate. It is not clear, for instance, whether and to what extent the agency’s Final Rule is influenced by the proposals’ assertion that the capital costs of NGCCs exceed those of CTs by

---

[35] 2024 Efficient Generation TSD at 33.

[36] *Id.* at 35.

250 percent for comparably sized units. In our comments, Petitioners considered four comprehensive studies conducted by or for reputable sources—including the U.S. Department of Energy's National Renewable Energy Laboratory (NREL),[37] EIA,[38] the California Energy Commission,[39] and PJM[40]—that directly conflict with that assertion. The results of those studies are presented in the table below.

<u>Fig. 3: Comparison of NGCC and CT Overnight Capital Cost Estimates</u>

Source of cost estimate	Combined cycle unit – capacity/heat rate	Capital cost ($/kW)	Simple cycle unit - capacity/heat rate	Capital cost ($/kW)
NREL (2023)	F Frame- 727 MW/ 6363 Btu/kWh H Frame- 992 MW/ 6196 Btu/kWh	$1105–09 $1134–41	F Frame- 233 MW/9,717Btu/kWh	$995
EIA AEO (Sargent & Lundy) (2019)	GE 7HA.02 2x2x1- 1083 MW/6370 Btu/kWh H Class 1x1x1- 418 MW/6431 Btu/kWh	$958 $1084	2 x LM 6000- 105 MW/9124 Btu/kWh 1x GE 7FA- 237 MW/9905 Btu/kWh	$1175 $713
Cal Energy Comm'n (2019)	640 MW/7250 Btu/kWh 700 MW/7250 Btu/kWh	$914 (mid-case) $890 (mid-case)	NextGen LM6000- 49.9 MW/10,585 Btu/kWh 2 x NextGen	$1190 (mid-case)

[37] Nat'l Renewable Energy Laboratory, *Related Datasets 2023 Annual Technology Baseline (ATB) Cost and Performance Data for Electricity Generation Technologies*, 2023_v1_Workbook_06_28_23.xlsx (tab titled "Natural Gas_FE"), https://data.openei.org/files/5865/2023%20v1%20Annual%20Technology%20Baseline%20Workbook%20Original%206-28-2023%20(1).xlsx.

[38] Sargent & Lundy Consulting, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, Table 2—Cost & Performance Summary Table (Dec. 2019), https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.

[39] Cal. Energy Comm'n, E*stimated Cost of New Utility-Scale Generation in California: 2018 Update*, Table B-25 (May 2019), https://www.energy.ca.gov/sites/default/files/2021-06/CEC-200-2019-005.pdf.

[40] The Brattle Group/Sargent & Lundy Consulting, *PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date*, Table 9: Plant Capital Costs for CT Reference Resource in Nominal $ for 2022 Online Date and Table 10: Plant Capital Costs for CC Reference Resource in Nominal $ for 2022 Online Date (Apr. 19, 2018) https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx.

			LM6000- 100 MW/10,585 Btu/kWh 200 MW/9880 Btu/kWh	$1185 (mid-case) $971 (mid-case)
PJM (The Brattle Group/Sargent & Lundy) (2018)	GE 7HA.02 2x1- 1140 MW/~6300 Btu/kWh	$772–873	GE 7HA.02- 320 MW/~927- Btu/kWh	$799–898
Average of Studies		$988		$1011

These studies indicate that NGCC units have, on average, *lower* capital costs than comparably sized CTs. This fact is further supported by the most recent EIA study published after the comment period closed, which, as mentioned above, show NGCC capital costs ranging from $868 to $921/kW and CT capital costs ranging from $836 to $1606/kW.[41] Of course cheaper capital costs standing alone do not justify regulatory choices, and do not account for operation and maintenance or fuel costs. However, these data indicate that EPA's unsupported 250 percent figure in the proposal was incorrect, and the agency has not disavowed that figure or otherwise rebutted the data cited above. A reconsideration process would clarify what EPA actually believes about comparative capital costs, would require it to consider the full range of available data sources, and would allow petitioners the opportunity to properly address EPA's approach to costs.

In addition, our comments also compared the capital and fuel costs of NGCCs and CTs in relation to the social value of the CO_2 that would be reduced by more protective regulatory standards consonant with the best system of emission reduction. Although this process does not consider operation and maintenance costs (as would a full LCOE analysis), the outcome indicates that, for comparably sized units at the generation capacities analyzed, the environmental benefits of NGCC operations would still be worth additional compliance costs even at very low capacity factors.[42]

<u>Fig. 4: Cost-Effectiveness Comparison of Comparable Combined Cycle and Simple Cycle Units</u>

	Overnight capital costs	Fuel costs	Operator's cost	CO_2 emissions (mt)	Social cost of CO_2 emissions
20% Capacity Factor					
3 F-class CTs (699 MW)	$56,050,748	$48,375,179	$104,425,927	758,579	$52,341,964
F-class 2x1 NGCC (727 MW)	$62,472,643	$34,013,797	$96,486,440	533,376	$36,802,944
Incremental Benefit for	-$6,421,895	$14,361,381	$7,939,486	225,203	$15,539,021

41 EIA, *supra* n. 17, at Table 1-2.

42 The data assumptions and methodology for this analysis are provided in Sierra Club, et al. Comments at 15-16.

NGCC					
15% Capacity Factor					
3 F-Class CTs (699 MW)	$56,050,748	$36,281,384	$92,332,132	568,934	$39,256,473
F-Class 2x1 NGCC (727 MW)	$62,472,643	$25,510,348	$87,982,991	400,032	$27,602,208
Incremental Benefit for NGCC	-$6,421,895	$10,771,036	$4,349,141	168,902	$11,654,265
10% Capacity Factor					
3 F-Class CTs (699 MW)	$56,050,748	$24,187,589	$80,238,337	379,290	$26,170,982
F-Class 2x1 NGCC (727 MW)	$62,472,643	$17,006,899	$79,479,541	266,688	$18,401,472
Incremental Benefit for NGCC	-$6,421,895	$7,180,691	$758,796	112,602	$7,769,510
5% Capacity Factor					
3 F-Class CTs (699 MW)	$56,050,748	$12,093,795	$68,144,543	189,645	$13,085,491
F-Class 2x1 NGCC (727 MW)	$62,472,643	$8,503,449	$70,976,092	133,344	$9,200,736
Incremental Benefit for NGCC	-$6,421,895	$3,590,345	-$2,831,549	56,301	$3,884,755

The data provided above are stark: under the 20, 15, and 10 percent capacity factor scenarios, combined cycle operation for the model units studies is far more environmentally beneficial compared to simple-cycle operation *and* more economically advantageous to operators and ratepayers, as the savings in fuel costs resulting from the NGCC's superior efficiency exceed its additional capital costs in each case. Only under the 5 percent capacity factor scenario do the ratepayers see higher costs as a result of combined cycle operation, and yet even then, the social benefits of reduced CO_2 emissions outweigh those economic disbenefits.

In the Final Rule, EPA suggests that such analyses are inapt because they do not account for variable operations (and attendant fluctuation sin emission rates) and the fact that CTs are often much smaller than NGCCs, and thus have different cost characteristics. See 89 Fed. Reg. at 39,911. Yet the assumption about variability assumes that frequent starting and stopping occurs in intermediate-load operations, when it instead characterizes peaking operations. Moreover, even at lower capacities like 50 and 100 MW, EPA's own LCOE data show that NGCCs are still the cost-effective control option insofar as any additional compliance costs do not exceed the monetized benefits of the CO_2 reductions achieved. Finally, even if EPA could show that NGCCs that are either small in capacity or that must cycle frequently would not be cost-justified, the agency did not consider establishing a separate sub-category for that class of units based on simple cycle technology as the BSER. Instead, EPA has painted with an overly broad brush, establishing CTs as the BSER for *all* intermediate-load units. A reconsideration proceeding would ensure EPA adopts standards consistent with the best system of emission reduction.

Given the economic and environmental advantage of operating combined cycle unit even at low capacity factors, one may wonder why so many existing simple cycle units nonetheless continue to operate at levels above single-digit capacity factors. There are two basic answers to this. First, because simple cycle units invariably have higher marginal operating costs than combined cycle facilities, a given CT will only be called upon to dispatch when all of the available NGCCs in a given load-balancing area are already up and running. Second, a large portion of the combined cycle fleet was constructed approximately 20 years ago, when fast-start NGCCs—which are far superior to older, conventional NGCCs to use for peaking purposes and operating at lower capacity factors—were not available. Thus, simple cycle units have provided much of the generation at lower capacity factors, and have operated at higher capacity factors when combined cycle generation has been effectively maxed out in a given service area.

This is a description of how the gas fleet has operated for the last two decades given the economic and technical factors from 20 years ago. EPA's rule, however, determines what is required for combustion turbines *going forward*. The purpose of section 111(b) standards is not simply to accommodate aging, suboptimal technologies. On the contrary, it is designed as a "technology-forcing" provision. As the D.C. Circuit has held, "EPA does have authority to hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible and will produce the improved performance necessary to meet the standard." *Sierra Club v. Costle*, 657 F.2d 298, 364 (D.C. Cir. 1981). The data above show that it is not just feasible but advantageous to require combined cycle technology for units operating in intermediate-load applications.

c. EPA's selection of simple cycle technology as the BSER for intermediate-load turbines remains unjustified in the Final Rule.

As noted previously, at proposal, EPA justified its selection of simple cycle CTS as the BSER for intermediate-load units with the following two sentences:

> The EPA considered but is not proposing combined cycle unit design for combustion turbines in the intermediate subcategory because the capital cost of a combined cycle EGU is approximately 250 percent that of a comparable-sized simple cycle EGU and because the amount of GHG reductions that could be achieved by operating combined cycle EGUs as intermediate load EGUs is unclear. Furthermore, intermediate load combustion turbines start and stop so frequently that there might not be sufficient periods of continuous operation where the HRSG would have sufficient time to generate steam to operate the steam turbine enough to significantly lower the emissions rate of the EGU.

The material in the previous section offered Petitioners' response to this rationale and our basis for believing that these justifications do not support the agency's decision not to select combined cycle generation as the BSER for intermediate-load units. In the Final Rule, EPA offered the following discussion with regard to NGCC and CT operations at annual capacity factors below 40 percent:

> Direct comparison of the costs of combined cycle turbines relative to simple cycle turbines can be challenging because model plant costs are often for combustion turbines of different sizes and do not account for variable operation. For example,

combined cycle turbine model plants are generally for an EGU that is several hundred megawatts while simple cycle turbine model plants are generally less than a hundred megawatts.

Direct comparison of the LCOE from these model plants is not relevant because the facilities are not comparable. Consider a facility with a block of 10 simple cycle turbines that are each 50 MW (so the overall facility capacity is 500 MW). Each simple cycle turbine operates as an individual unit and provides a different value to the electric grid as compared to a single 500 MW combined cycle turbine. While the minimum load of the combined cycle facility might be 200 MW, the block of 10 simple cycle turbines can provide from approximately 20 MW to 500 MW to the electric grid.

A more accurate cost comparison accounts for economies of scale and estimates the cost of a combined cycle turbine with the same net output as a simple cycle turbine. Comparing the modeled LCOE of these combustion turbines provides a meaningful comparison, at least for base load combustion turbines. Without accounting for economies of scale and variable operation, combined cycle turbines can appear to be more cost effective than simple cycle turbines under almost all conditions. In addition, without accounting for economies of scale, large frame simple cycle turbines can appear to be more cost effective than higher efficiency aeroderivative simple cycle turbines, even if operated at a 100 percent capacity factor. These cost models are not intended to make direct comparisons, and the EPA appropriately accounted for economies of scale when estimating the cost of the BSER. Since base load combustion turbines tend to operate under steady state conditions with few starts and stops, startup and shutdown costs and the efficiency impact of operating at variable loads are not important for determining the compliance costs of base load combustion turbines.

Based on an adjusted model plant comparison, combined cycle EGUs have a lower LCOE at capacity factors above approximately 40 percent compared to simple cycle EGUs operating at the same capacity factors. This supports the final base load fixed electric sales threshold of 40 percent for simple cycle turbines because it would be cost-effective for owners/operators of simple cycle turbines to add heat recovery if they elected to operate at higher capacity factors as a base load unit. Furthermore, based on an analysis of monthly emission rates, recently constructed combined cycle EGUs maintain consistent emission rates at capacity factors of less than 55 percent (which is the base load electric sales threshold in subpart TTTT) relative to operation at higher capacity factors. Therefore, the base load subcategory operating range can be expanded in 40 CFR part 60, subpart TTTTa, without impacting the stringency of the numeric standard.

However, at capacity factors of less than approximately 40 percent, emission rates of combined cycle EGUs increase relative to their operation at higher capacity factors. It takes much longer for a HRSG to begin producing steam that can be used to generate additional electricity than it takes a combustion engine to reach

> full power. Under operating conditions with a significant number of starts and stops, typical of some intermediate and especially low load combustion turbines, there may not be enough time for the HRSG to generate steam that can be used for additional electrical generation. To maximize overall efficiency, combined cycle EGUs often use combustion turbine engines that are less efficient than the most efficient simple cycle turbine engines. Under operating conditions with frequent starts and stops where the HRSG does not have sufficient time to begin generating additional electricity, a combined cycle EGU may be no more efficient than a highly efficient simple cycle EGU. These distinctions in operation are thus meaningful for determining which emissions control technologies are most appropriate for types of units. Once a combustion turbine unit exceeds approximately 40 percent annual capacity factor, it is economical to add a HRSG which results in the unit becoming both more efficient and less likely to cycle its operation. Such units are, therefore, better suited for more stringent emission control technologies including CCS.

89 Fed. Reg. at 39,911.[43]

Before addressing EPA's response in detail, we reiterate that this Petition is not focused on units that typically operate at less than the 30 minutes to an hour per start, which is the margin that fast-start NGCC require to generate full power from the HRSG. Rather, Petitioners object to the use of CTs that operate with only one start per day and with operating run times more than 5 hours per start. Petitioners understand that some CTs serve true "peaking" needs, but continue to believe that the EPA's annual capacity factor test is insufficient to differentiate between true peaking units and intermediate-load (including both typical load-following and seasonal baseload/load following) operations that should be served by NGCCs. Intermediate-load units typically have just one start per operating day and run for 10 hours or more per start. In our comments on the proposed rule, Petitioners suggested that the test for simple cycle peaking units should be an annual capacity factor of 5-8 percent and a monthly capacity factor of 15 percent. The EPA has not demonstrated why such a test would not better characterize peaking needs or adequately support renewable generation. Nor has the EPA explored other potential tests, such as a 30-operating-day of 5-hours-per-start-average.

Below, we address in turn EPA's arguments included in the quote above.

First, contrary to EPA's implication that combined cycle EGUs are always large units, they in fact exist in a broad array of sizes, ranging from 10 MW to several hundred or over 1,000 MW. And while individual CTs may operate as distinct units, their use—like the use of all power plants, including NGCCs—is coordinated by the ISO/RTO and the grid operator. Thus, the agency is simply incorrect in its claims that CTs have characteristics that are so unique and operationally flexible that valid comparisons of their cost and efficiency with NGCCs cannot be made at anything other than baseload levels. When configured in a 2x1 or 3x1 mode, NGCCs offer a range of coverage that is equivalent or greater than what can be provided by a bank of multiple CTs alone. In fact, there is nothing to prevent such a bank of new CTs from feeding into a single HRSG and steam turbine, either technologically or operationally.

[43] *See also* 89 Fed. Reg. at 39,920-21.

In this regard, EPA response wrongly assumes that economies of scale at simple cycle units are otherwise unavailable. By universally treating CTs as isolated units rather than components of a larger facilities—which they most often are—the agency both overlooks the opportunity for more economical HRSG installations and assumes (for LCOE comparison purposes) that these units are not comparable with larger NGCCs. EPA's Efficient Generation TSD identifies 169 simple cycle turbines at 36 plants as best performers. [44] Petitioners have reviewed this list[45] and determined that only three of those units could be characterized as (1) small and (2) the only combustion turbine at the facility and so less capable of benefiting from economies of scale. One of those three units (Culbertson) had a capacity factor of 43 percent in 2023[46] and so would, under the agency's definition of *baseload* operations, have to reduce utilization anyway or add a HRSG if it were a new unit. The other 166 CT were either large CTs or co-located with other units and would be fully capable of sharing an HRSG with other units provided on-site space exists.[47]

Second, EPA's argument regarding the lower efficiencies of NGCC units operating below 40 percent annual capacity factors is misguided. While thermal plants typically exhibit some efficiency degradation at lower capacity factors, the data indicate that this phenomenon affects NGCCs substantially less than CTs, and that HRSG performance is fairly stable even at low loads. The following analyses are from a National Energy Technology Laboratory (NETL) report[48] that EPA relied on for this purpose in the Final Rule but not the proposal. In this study, NETL staff evaluate the part load performance of a fast-start aeroderivative CT and two frame NGCCs. NETL's analysis demonstrate that the NGCC units evaluated can provide several hundred MW of ramping capacity to support RE while themselves maintaining lower emission rates than the CT analyzed. Below, Figure 5 depicts the efficiency trend of the CT analyzed by NETL at different load points, while Figures 6 and 7 provide the same information for the two NGCCs included in the study. Figure 9 provides a table of the three units' CO_2 emission rates at different load percentages.

---

[44] EPA, Efficient Generation: Combustion Turbine Electric Generating Units (Emissions Data) Technical Support Document (TSD), Dkt. No. EPA-HQ-OAR-2023-0072-9100 Attachment 1, Fig. 1 (Apr. 2024), https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-9100/attachment_1.pdf.

[45] Petitioners' analysis is presented as Attachment 2 to this Petition.

[46] CAMPD query.

[47] Of course, at new sources—which are the subject of the Final Rule for which we seek reconsideration—owners/operators can build an HRSG into the initial design for the facility, so space constraints will never be an issue for such plants.

[48] NETL*, Cost and Performance Baseline for Fossil Energy Plants, Vol. 5: Natural Gas Electricity Generating Units for Flexible Operation*, Dkt. No. EPA-HQ-OAR-2023-0072-9100, Attachment 15 (May 5, 2023), https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-9100/attachment_15.pdf.

Fig. 5: Efficiency of CT in NETL Report at Different Load Points [49]

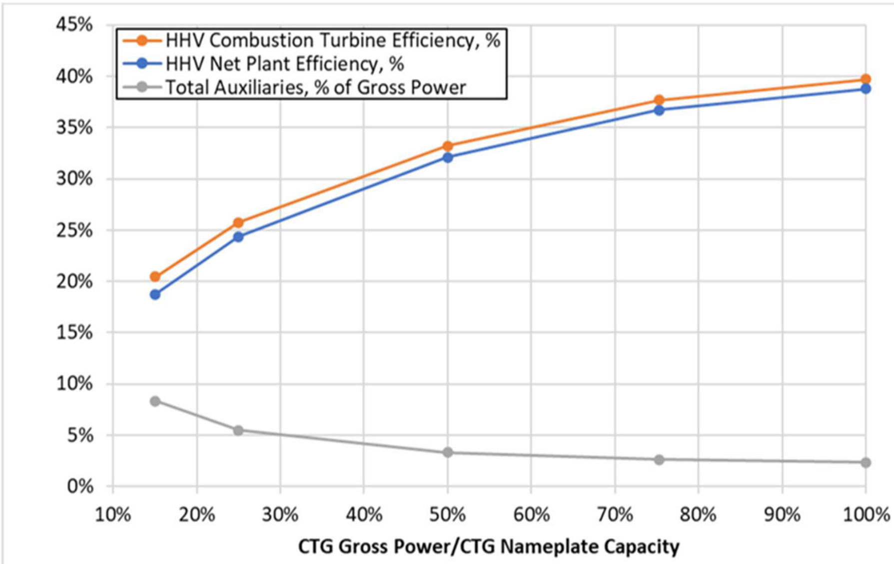
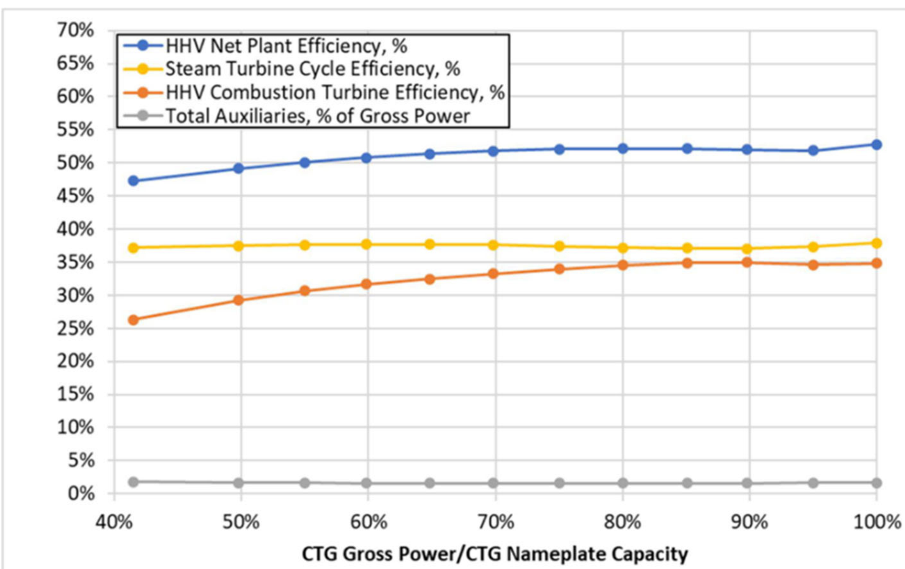


Fig. 7: Efficiency of First NGCC in NETL Report at Different Load Points [50]



[49] *Id.* at 131.
[50] *Id.* at 173.

Fig. 8: Efficiency of Second NGCC in NETL Report at Different Load Points [51]

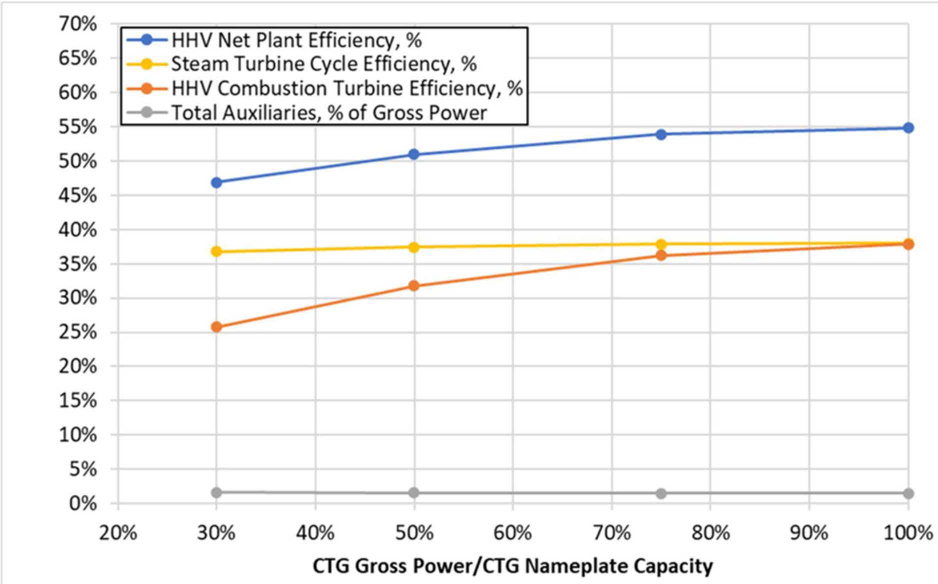


Fig. 9. CO_2 Emission Rate (lb/MWh-net) Comparisons Between Simple Cycle and Combined Cycle Units in NETL Study[52]

Load (%)	100	90	80	75	60	50	40	30	25	15
SC1A	1044			1104		1262			1667	2165
CC1AF	754	766	764	764	788	810	842			
CC1AH	727			739		781		850		

As these figures show, NGCC units exhibit *much* more consistent efficiency at low load compared to CTs, a fact that seriously undercuts the agency's rationale for excluding them from the BSER for intermediate-load operations.

In addition to load, lower efficiency is influenced by a number of factors, especially the number of start/stop cycles per day (as EPA notes), but the unit's annual capacity factor is not necessarily determinative of the frequency of starting and stopping. This is especially true in the case of seasonal load following units, which effectively operate in baseload or load-following mode for only one to three months per year and otherwise lay dormant. Petitioners recognized this fact in their comments respecting the appropriate definition of a "peaking" unit and provided specific EPA data concerning the performance of CT and NGCC units in seasonal load-following mode.[53] Those data demonstrated that combined cycle units can serve as seasonal load-following and typical intermediate-load applications at far lower emission rates than comparable CT units. EPA has offered no information to dispute the assertion of the representativeness of the data that

[51] *Id.* at 194.
[52] *See id.* at pp. 130, 172, and 193.
[53] Sierra Club, et al. Comments at 24-27.

Petitioners cited in their comments.

Furthermore, even to the extent that EPA is correct in asserting that units operating below 40 percent tend to exhibit efficiency losses, EPA has provided no data indicating that the *degree* of that loss justifies its BSER selection from an environmental and economic standpoint. Instead, it offers bare, unsupported assertions. For instance, EPA claims that "[t]o maximize overall efficiency, combined cycle EGUs ***often*** use combustion turbine engines that are less efficient than the most efficient simple cycle turbine engines. Under operating conditions with frequent starts and stops where the HRSG does not have sufficient time to begin generating additional electricity, a combined cycle EGU ***may be*** no more efficient than a highly efficient simple cycle EGU." 89 Fed. Reg. at 39,911 (emphasis added). How often is "often," and how likely is "may be," are left undefined.

By contrast, EPA's own data on power plant emissions reveal an entirely different picture. Although CAMPD's data query tool for power plant emissions does not include a field for annual capacity factors, we can estimate the emissions performance of the relevant units by comparing CT and NGCC emission rates for units with annual hours of operation between 1,000 and 4,000 hours, which are typical of intermediate-load applications.[54] The data reveal that in 2023, CT units in this cohort had CO_2 emission rates that were approximately 18.3 percent higher than NGCCs. Even considering just units operating between 1,000 and 2,000 hours per year, we found that CTs had a 11.7 percent higher CO_2 emission rate compared to NGCCs.[55] Thus, while *individual* NGCCs might operate at lower efficiencies than the top-rated CTs, this is decidedly not the case for the fleet as a whole. And for the newest, most highly-efficiency NGCCs with fast-start capabilities, the advantage would likely be greater still.

EPA might respond that this analysis does not address the number of starts and stops per day (or per year), which (as noted above) has a correlational but not necessarily causal relationship with lower annual capacity factors. Yet it was EPA itself that decided to distinguish between low-load and intermediate-load turbines on the basis of annual capacity factors, not number of daily starts and stops. If the agency believes—and can show through data—that there are some units operating at intermediate-load capacity factors that start and stop with such frequency to justify excluding an HRSG requirement, it should either establish a regulatory carve-out for those units or simply define low-load units based on frequency of starts/stops, not annual capacity factors. Similarly, to the extent that EPA can demonstrate that small units—meaning CTs under a low megawatt threshold that are not co-located with other such units—cannot install and operate HRSGs while reducing CO_2 cost-effectively, it should include those units in a separate sub-category. Instead, EPA has effectively catered to the lowest common denominator and established a flawed BSER—simple-cycle technology—for *all* intermediate-load units. The agency must strengthen the rule in a reconsideration proceeding in accordance with the requirements to establish the best system of emission reduction.

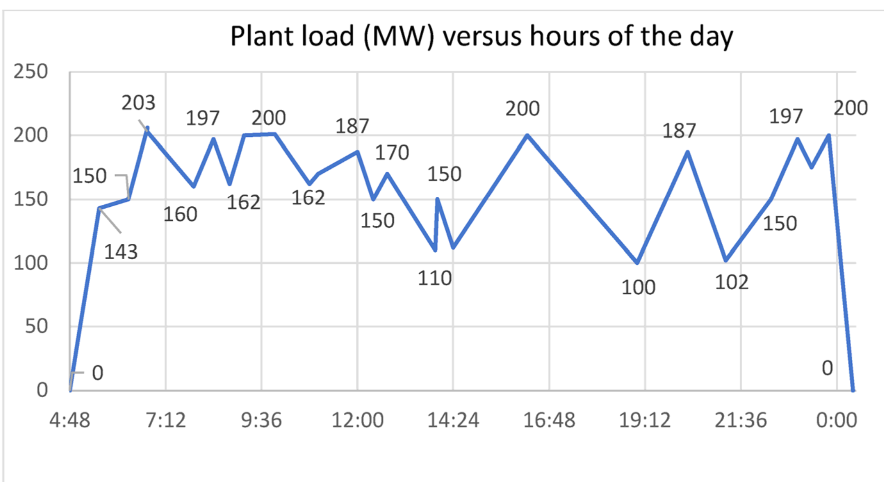
Third, the agency's discussion about fast-start NGCCs in the Final Rule does not support its rationale to establish CTs as the BSER for intermediate-load units. EPA claims that fast-start

[54] CAMPD query.
[55] CAMPD query. This was the data set we used to extract $/ton cost-effectiveness values from EPA's LCOE table in the 2024 Efficient Generation TSD, discussed in Section III.b, *supra*.

NGCCs cannot meet intermediate-load needs because they are "significantly less flexible than simple-cycle turbines," requiring 30-45 minutes to reach full capacity upon hot starts (compared to 5-8 minutes for CTs) and 120 minutes to reach full capacity upon cold starts (compared to 10 minutes for CTs). 89 Fed. Reg. at 39,919. As noted in Section II, this directly contradicts the documented information that EPA included in its own Efficient Generation TSD, which demonstrates that fast-start NGCCs can, in fact, reach full capacity within 30-45 minutes of a cold start. It also ignores the TSD's discussion of the fact that the use of a bypass stack at an NGCC allows the combustion turbine to reach full load within 10 minutes (for hot start) to 20-25 minutes (for a cold start), with the steam cycle components ramping up thereafter.[56]

Perhaps more importantly, these assertions by EPA in the Final Rule—as well as its additional discussion in that section of the preamble of average run times, down times, and hours/start for NGCCs relative to CTs, *see* 89 Fed. Reg. at 39,919—rely on the mistaken assumption that intermediate-load applications require very frequent starts and stops and extremely rapid start-times. Petitioners do not necessarily suggest that units that operate for just a few hours per start must be NGCCs, but such units are not at all characteristic of intermediate-load operation. In fact, intermediate-load EGUs generally operate for most of the day, turning on in mid-morning and running (at various load levels) until the night, at which point they shut off during the period of lowest demand. The figure below depicts the typical operation of an intermediate-load combined cycle unit over the course of the day. While its load indeed fluctuates, the unit does not start and stop frequently, as EPA suggests, but instead only shuts off entirely for approximately five hours when demand is lowest.

<u>Fig. 5: Daily Load Pattern of Intermediate-Load NGCC Unit</u>[57]



The experience in California exemplifies this fact. This state has a particularly high level of wind and solar penetration—non-hydro renewables provided 41 percent of California's generation in

[56] 2024 Efficient Generation TSD at 29.
[57] Hiyam Farhat and Coriolano Salvini, *Novel Gas Turbine Challenges to Support the Clean Energy Transition*, 15 ENERGIES 5474, Fig. 7 (2022), https://doi.org/10.3390/en15155474, included as Exhibit 6.

2023[58]—and so its NGCC units typically operate in load-following applications to support intermediate renewable resources. In 2015, California passed a law requiring the state to generate at least 50 percent of its electricity from renewable resources by 2030,[59] and a subsequent study found that this would increase the number of starts/stops at the state's NGCCs—but that all such units would still average less than one start/stop per day.[60]

The problem of seasonal load-following units adds particular emphasis to the flaws in EPA's reasoning. As discussed previously, this occurs when units operate at high capacity factors (sometimes at baseload levels) for one to three months out of the year and otherwise lay dormant. This results in low annual capacity factors for these units—sometimes below 20 percent, and certainly below 40 percent—but reflects few starts and stops per unit. Under EPA's current approach, simple-cycle turbines could generate at (for instance) 80 percent load with around-the-clock operations—essentially never starting and stopping apart from maintenance needs—for six months out of the year, resulting in an emission rate up to 30 percent higher than an equivalent NGCC. This example demonstrates particularly starkly why the agency is simply wrong to assume that units operating at annual capacity factors below 40 percent start and stop with such frequency as to exclude NGCC technology from BSER consideration.

Fourth, the agency does not support its implications about grid reliability. In the Final Rule, EPA suggests (although does not outright state) that a CT-based BSER for intermediate-load units is necessary to ensure a reliable supply of electricity, indicating that it "does not have sufficient information to determine that an intermediate-load combined cycle turbine can start and stop with enough flexibility to provide the same level of grid support as intermediate load simple cycle turbines as a whole." 89 Fed. Reg. at 39,920. This is flawed for multiple reasons. First, as noted above, intermediate-load units simply do not start and stop as frequently as EPA claims, and in any event, its capacity factor-based thresholds do not reflect this frequency. Second, in cases of NERC level 2 or 3 emergencies, the Final Rule already excludes both CO_2 and generation produced by affected units from factoring into both compliance and the unit's proper subcategory determination. 40 C.F.R. § 60.5525a(c)(3). Finally, while the agency must address "energy requirements" in making BSER designations, 42 U.S.C. § 7411(a)(1), and must ensure that its standards do not undercut grid reliability, the primary entities responsible for overseeing the electric grid are FERC (at the wholesale level) in collaboration with NERC, state public utilities commissions (at the retail level), and ISOs/TROs. Nothing about a combined-cycle BSER for intermediate-load EGUs would jeopardize the ability of these entities to manage portfolios accordingly, ensure that sufficient reserve capacity exists to meet emergency needs, and ultimately ensure a reliable supply of electricity based on the unique needs of each grid region.

---

[58] EIA, *Profile Analysis for California* (May 16, 2024 update), https://www.eia.gov/state/analysis.php?sid=CA (last visited July 3, 2024).

[59] SB 350. SB 100, passed in 2018, increased these requirements to 60 percent in 2030 and 100 percent in 2045.

[60] Union of Concerned Scientists, *Turning Down the Gas in California: The Role of Natural Gas in the State's Clean Electricity Future*, 6 (Aug. 2018), https://www.ucsusa.org/sites/default/files/attach/2018/07/Turning-Down-Natural-Gas-California-fact-sheet.pdf.

Fifth, and lastly, it is worth reiterating the obvious fact that EPA *is* an environmental regulator. Indeed, EPA has long acknowledged—including in the Final Rule—that the "quantity of emission reductions at issue" is a key factor in its determination of the BSER under section 111. 89 Fed. Reg. at 39834 (citing *Sierra Club v. Costle*, 657 F.2d 298, 326 (D.C. Cir. 1981)). Yet in all its discussion of starts and stops, its LCOE comparisons between NGCC and CT models, and its assertions about lower efficiencies below certain capacity factor thresholds, EPA only discusses CO_2 reductions in the vaguest and most indirect terms. Yet the actual emissions data, which we have cited in detail but which the agency has left unaddressed, show that NGCC operations, even at low levels of annual operation, achieve substantial emission reductions compared to CTs. Our comments on the proposed rule also showed that, even using the most conservative estimates available to us, the quantified CO_2 emission reduction benefits NGCC versus CT operations outweigh any potential cost increases (which are at most levels offset anyway by fuel savings) when comparing fairly large units. And even EPA's own LCOE analysis in the 2024 Efficient Generation TSD indicate that, at intermediate-load levels, the monetized benefits of CO2 reductions still outweigh any added compliance costs of operating an NGCC rather than CT—*even at capacities of just 50 and 100 MW*.

The emission reduction benefits of operating NGCCs rather than CTs extend beyond CO_2. To cite just one data point, our earlier analysis of CAMPD data for NGCCs and CTs operating between 1,000 and 4,000 hours per year show that the NO_x emission rates of simple cycle units in this cohort are over 60 percent higher than their combined cycle counterparts. Any reconsideration proceeding that EPA convenes must more closely consider and analyze the emission reduction benefits that would result from a BSER based on NGCC rather than CT technology for intermediate-load units, even after accounting for reduced efficiencies at lower load.

IV. In Reconsidering the Final Rule, EPA Must Lower the Threshold Separating Low-Load from Intermediate-Load Units

In our comments on the proposed rule, Petitioners urged EPA to align the low-load subcategory with the generally accepted definition of peaking units, which—according the multiple sources we cited—typically operate at annual capacity factors of between 5 and 8 percent. In addition, we recommended a monthly capacity factor cut-off of 15 percent to prevent units operating in seasonal baseload/load-following capacity to qualify as low-load EGUs and thus avoid a more stringent emission rate.

In the Final Rule, EPA retained the 20 percent annual capacity factor threshold, reasoning that "[t]he fixed 20 percent capacity factor threshold represents a level of utilization at which most simple cycle combustion turbines perform at a consistent level of efficiency and GHG emission performance." 89 Fed. Reg. at 39,913. Paradoxically, on the prior page of the preamble, EPA states that "at a capacity factor above 15 percent, GHG emission rates for many simple cycle turbines begin to stabilize." *Id.* at 39,913. This alone warrants a reconsidered threshold: if EPA believes that the emissions stabilization point for CTs is the proper basis to separate low-load from intermediate-load units, then a 15 percent annual capacity, not 20 percent, is the proper cut-point according to the agency's own reasoning.

Moreover, EPA's reasoning reflects the performance of simple cycle units, and ignores the possibility that fast-start NGCCs may be appropriate for applications well below even a 15 percent annual threshold. As demonstrated in the NETL report EPA included in the docket, which we discussed above, NGCCs not only perform at far superior emission rates at relatively low loads compared to CTs, but suffer far less efficiency degradation compared to their own performance at high loads. Just as the agency has not justified excluding these units from the BSER for the higher range of intermediate-load EGUs (i.e., those operating at between 20 and 40 percent annual capacity factors), it must also reconsider the availability of such units for operations below 20 percent but above the 5-8 percent range for true peakers, where 10-minute starts up may be more necessary. And to the extent variability of emission rates *is* an issue at lower capacity factors for some class of sources, the agency has selected a 12-month rolling average standard. This is a sufficiently long compliance period to account for fluctuations that might occur during that time; there is no basis for such units to be entirely exempt from output-based standards.

In addition, the 20 percent threshold does not account for the operation of seasonal load-following/baseload units. A unit that runs at a capacity factor of 80-100 percent for two months out of the year but otherwise shuts down will have an annual capacity factor of approximately 13-17 percent, and thus fall within EPA's low-load definition—at which emission rates are allegedly so variable that an output-based standard is not appropriate—despite running in baseload capacity when it does operate. There is no reason such units cannot be expected to perform at a level commensurate with the most efficient NGCCs, but under the current approach they are not even subject to an output-based standard.

To support its 20 percent threshold, EPA also cited the fact that "[o]f recently constructed simple cycle turbines, half have maintained 12-operating month capacity factors of 15 percent or less, two-thirds have maintained capacity factors of 20 percent or less; and approximately 80 percent have maintained maximum capacity factors of 25 percent or less." 89 Fed. Reg. at 39,912. Yet EPA need not accommodate what industry already does: as the agency has itself stated many times in the past—including in other sections of this same preamble—"section 111(a)(1) authorizes a technology-forcing standard," *id.* at 39,832, and should result in the adoption of technologies in a way that pushes the industry forward, rather than simply follow what it is already doing. If two-thirds of recently built CTs already run below 20 percent and half run below 15 percent on an annual basis, the sector is fully capable of meeting a standard that reflects a low-load subcategory with a capacity factor threshold below 15 percent, and certainly below 20 percent. Finally, if necessary, EPA can create additional subcategories to account for classes of sources (for instance, small-capacity units, or those that must start/stop much more frequently than average) that operate between our suggested 5-8 percent low-load cut-point and the agency's current 20 percent figure.

V. In Reconsidering the Final Rule, EPA Must Establish Standards of Performance for Combustion Turbines Below 25 MW.

EPA has provided no rationale for its decision to exempt units that are 25 MW and smaller from emission standards under the Final Rule. As noted earlier, it simply asserts that it "did not propose and is not finalizing emission standard for electric generating units selling less than 25

MW to the grid at this time."[61] Yet regulating these units would not represent a departure from EPA's authority or past practice: the agency has a long history of regulating numerous classes of "smaller" sources under section 111 that, as a group, generate harmful emissions, some of which produce orders of magnitude less power output per unit than the sources EPA has exempted in the Final Rule. To name a few categories, these include small institutional, commercial, and industrial boilers ("ICI boilers") (40 C.F.R. § 60, subpart Dc, covering units starting at 2.9 MW, see *id.* at § 60.40c(a)); stationary compression internal combustion engines (*id.* at subpart IIII, providing no size-based exemptions but establishing tiered standards for sources below 2.237 MW, between 2.237 and 3.7 MW, and above 3.7 MW at *id.* § 60.4201); spark ignition internal combustion engines (40 C.F.R. § 60, subpart JJJJ, providing no size-based exemptions but distinguishing between units above and below 19 KW, see *id.* § 60.4230); residential wood heaters, hydronic heaters, and forced air furnaces (*id.* at subparts AAA and QQQQ, providing no size-based exemptions but generally covering units in the range of 15,000 to 100,000 BTU/hr, which is equivalent to 4.3 to 29 KW, *see* 80 Fed. Reg. 13,672, 137,34 (Mar. 16, 2015)).

A 24.9 MW CT has potential CO_2 emissions of approximately 160,000 tons per year.[62] We estimate that there are now operating nearly 1,000 CTs that qualify for EPA's exemption. We know of no economic or technical barrier that would preclude EPA from establishing a performance standard for these units to ensure that they do not operate outside of their intended peaking mode. The agency must thus reconsider its decision to exempt these sources from the Final Rule's regulatory program.

At a minimum, EPA must develop standards for co-located units that collectively exceed the 25 MW threshold. While some of the exempt EGUs are stand-alone units, many others are co-located with one, two, three, or more CTs, in some cases greatly exceeding the 25 MW in the aggregate. For example, the Narrows Generating Station is a floating "power barge" located in New York's Upper Bay between Brooklyn and Staten Island. This facility consists of 16 simple-cycle turbines, each 22 MW and thus below the applicability threshold, that together amount to 352 MW[63]—equal in capacity to many combined cycle units. In reconsidering the Final Rule, EPA should close this potential loophole and assure that any such co-located units are not treated differently with regard to their CO_2 emissions than otherwise identical facilities that have fewer—but larger—turbines and are thus subject to the rule's requirements. The agency must therefore (a) eliminate or dramatically lower the 25 MW exclusion and (b) provide that where new small units located at units have a combined generating capacity greater than 25 MW, the performance standard for units greater than 25 MW applies.

VI. Conclusion

In the Final Rule, EPA acknowledges that there is more work to be done to ensure that new combustion turbines are properly controlled for their CO2 emissions, and has pledged to undertake additional analyses on a forward basis:

---

[61] EPA, *supra* n. 25.

[62] This figure assumes round-the-clock annual operation and an emission rate of approximately 1,450 lb/MWh, which is representative for CTs of this size.

[63] CAMPD query.

> In future rulemakings addressing GHGs from new as well as existing combustion turbines, the EPA intends to further evaluate the costs and potential emission reductions of the use of faster starting and lower cost HRSG technology for intermediate load combustion turbines to determine if the technology does in fact qualify as the BSER.

89 Fed. Reg. at 39,920. The people afflicted by climate-destabilizing pollution and other airborne contaminants cannot wait another 8 years for this review to occur. Thus, for the foregoing reasons, Petitioners respectfully request that the Administrator incorporate a proceeding for reconsideration of the Final Rule in accordance with Clean Air Act section 307(d)(7)(B) in its proposed additional regulatory action with respect to existing combustion turbine EGUs. As an alternative to the standard for mandatory reconsideration under section 307(d)(7)(B), we submit this as a petition for rulemaking pursuant to 5 U.S.C. § 553(e) and request that EPA grant reconsideration to each issue as a matter of discretion.

Respectfully submitted,

Andres Restrepo
Joanne Spalding
Sierra Club
50 F Street NW, 8th Floor
Washington, DC 20001
(856) 240-0964
andres.restrepo@sierraclub.org
joanne.spalding@sierraclub.org

Noha Haggag
Vickie Patton
Environmental Defense Fund
2060 Broadway, Ste. 300
Boulder, CO 80302
(202) 572-3286
nhaggag@edf.org
vpatton@edf.org

SUBMITTED VIA CERTIFIED AND ELECTRONIC MAIL

The Honorable Michael S. Regan, Administrator, EPA
Office of the Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Mail Code: 1101A
Washington, DC 20460

The petition was also submitted via email on the following: Joe Goffman, Tomás Carbonell, Alejandra Núñez, Peter Tsirigotis, Kevin Culligan, Jeffrey Prieto, and Susannah Weaver.

Enclosed: List of attachments included with Petition:

Attachment A – Sections III.A through III.D. from Comments of Sierra Club, Earthjustice, Conservation Law Foundation, and Appalachian Voices, EPA-HQ-OAR-2023-0072-0813 (Aug. 8, 2023).

Attachment B – Petitioners' Analysis of List of "Best-Performing" Simple-Cycle Combustion Turbines Provided in EPA's Efficient Generation TSD

Attachment A

Sections III.A through III.D. from Comments of Sierra Club, Earthjustice, Conservation Law Foundation, and Appalachian Voices, EPA-HQ-OAR-2023-0072-0813 (Aug. 8, 2023).

III. COMMENTS ON EPA'S PROPOSED STANDARDS OF PERFORMANCE FOR NEW COMBUSTION TURBINES.

As noted above, EIA projects a substantial growth of gas-fired combustion turbine generation in the coming decades, and it is critical that these units be controlled for their CO_2 emissions to the greatest extent possible. Although EPA's standards for new combustion turbines are, for some units, premised on technological controls that could substantially reduce end-of-stack emission rates—namely, carbon capture and sequestration (CCS) and hydrogen co-firing—the proposal does not establish sufficiently stringent requirements with regard to the base-level combustion turbine technologies in themselves. In other words, the current proposal leaves important, and easily achievable, emission reduction opportunities on the table by failing to require the lowest-emitting technology and practices for all units, including those that will *also* be subject to CCS or hydrogen co-firing. In this section, we propose ways in which the agency can and must tighten these aspects of the combustion turbines standards.

EPA's proposal would create a substantial difference in rigor and cost between the largest and most frequently operated combustion turbines and the rest of the fleet. This gap incentivizes sources to comply with applicable standards by way of load-shifting from higher-capacity factor to lower-capacity factor units, which runs the risk of eroding the standards' emission reduction potential. While this differential treatment may be cost-justified for certain technological applications, such as CCS, the agency can and should reduce the stringency gap by amending certain features of the rule as it is currently written.

For instance, EPA's proposal would fully exempt *all* smaller combustion turbines (i.e., units smaller than 25 megawatts (MW) in capacity)[16] from the rule's requirements. It would also *functionally* exempt all units operating below a 20 percent capacity factor, which would have no emission reduction obligations beyond what would likely be their standard operating practice even in the rule's absence. Furthermore, despite the rule's nominal "best system" designation of 30 percent hydrogen co-firing starting in 2032 for intermediate-load units, the agency provides what amounts to a nominal emission rate that the vast majority of such operators could easily attain even without the use of hydrogen by simply constructing and operating natural gas combined cycle ("NGCC") units.

As such, under the current proposal, only EPA's standards for baseload combustion turbines—those that elect to operate at capacity factors that exceed the unit's design efficiency—are likely to achieve substantial emission reductions. In the subsections that follow, we focus on several broad strategies that will improve the efficacy of the new source standards for turbines. First, EPA must designate combined cycle (rather than simple cycle combustion turbine, or "CT") technology as part of the best system of emission reduction for intermediate-load units (as it has already done for baseload units). It must also reduce the capacity factor threshold for units qualifying for the low-load subcategory from 20 percent on an annual basis to no more than 5 to 8 percent annually and 15 percent on a monthly basis. Using an improved methodology, EPA must then recalculate the baseline emission reduction rates for all affected sources, including an output-based CO_2 standard for low-load turbines (as

[16] The EPA proposal would exempt all units that are not capable of combusting more than 250 MMBtu/hour of fossil fuels. Proposed 40 C.F.R. §§ 60.5509a(a)(1), 0.5845b(b)(2). For combustion turbines this effectively exempts units less than 25MW.

opposed to the input-based "clean fuel" standard that EPA has currently proposed). Finally, EPA must ensure that small CTs (i.e., those below 25 MW) are not exempt from the standards.

A. EPA Must Designate Combined Cycle Technology—Not Simple Cycle Technology—as Part of the "Best System" for Intermediate-Load Units.

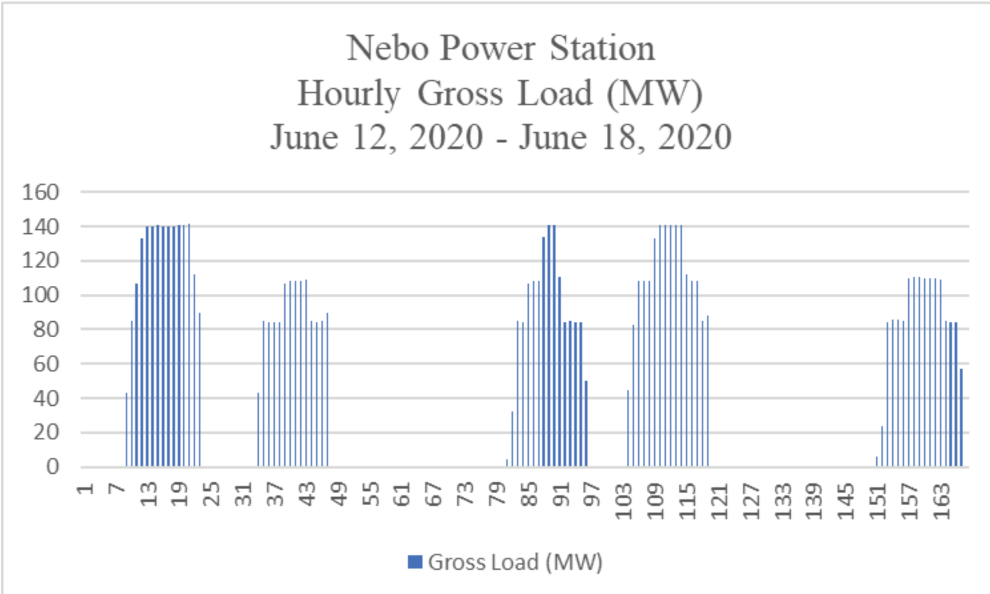
In a combined cycle or NGCC facility, the waste energy from the unit's combustion turbine is captured and employed to generate additional electricity. This provides an approximately 50 percent increase in efficiency—and an average of one-third less GHG emissions per MWh—compared to simple cycle CT technology. The NGCC's heat recovery steam generator (HRSG) is often installed after the combustion turbine has been operating for some period of time. This is not unlike retrofitting existing coal units with flue gas desulfurizers (FGD) or existing coal or gas units with selective catalytic reduction (SCR) to provide SO_2 and NO_x control, respectively.

Much of the existing combined cycle gas turbine fleet is now 20 or more years old and will soon reach a time where substantial retrofit or replacement with the most advanced new "fast-start" NGCCs will likely occur for a substantial number of units. These fast-start NGCCs initially fire the combustion turbine and quickly bring the HRSG on line. Accordingly, they can respond to rapid changes in demand while emitting far less CO_2 than the simple cycle CTs of two or three decades ago. Similarly, inlet cooling at operating units can quickly increase output by 10 percent or more of the rated output of larger NGCCs and thereby minimize the need to operate simple cycle peaking units. Weather and demand forecasting have also improved significantly, minimizing the need for "10-minute cold start" simple cycle turbines.

In fact, even NGCCs installed two decades ago—which are far less efficient than today's best units—are still capable of ramping up quickly enough to meet intermediate-load demands. For instance, the Nebo Power Station in Payson, Utah is a 140 MW combined cycle plant that commenced commercial operation on June 17, 2004.[17] It consists of a 65 MW gas turbine and a 75 MW steam turbine and has an SCR unit for NO_X control. As demonstrated below, even after 16 years of operation, this unit had no difficulty ramping up and down in a manner consistent with intermediate-load operations over the course of a representative one-week period in June 2020:

[17] All data that we cite regarding Nebo we acquired through a query to EPA's Clean Air Markets Program Database. EPA, *Clean Air Markets Program Data*, Custom Data Download (hereafter, "CAMPD query") https://campd.epa.gov/data/custom-data-download (last visited Aug. 2, 2023).

Fig. 1: Representative Hourly Gross Load of Nebo Power Station



Moreover, during this period, Nebo's emission rate was 872 lb/MWh(g), well within our proposed emission rate for intermediate-load turbines under 250 MW (*see* Table 5 below). A brand new unit equipped with the most state-of-the-art fast-start generation technology would show superior performance (and faster ramp times) still. In addition, operators may elect to employ the same fast-start and ramp-rate NGCCs that they otherwise would and, in rare instances in which an extremely short startup time[18] is required and the HRSG is not yet available, employ a bypass duct to operate the unit in simple cycle mode. While this is a suboptimal practice from both an economic and environmental standpoint, it can serve as a stop-gap for NGCCs in moments where very fast ramp-ups are required. Because our suggested emission limits are based on a rolling annual average, they provide a sufficient compliance margin to permit such infrequent and short-duration events without causing an exceedance. Further, the technology has advanced, through the use of exhaust stack dampers and revised startup routines to allow the HRSG to remain "warm" and available on short notice.[19]

[18] The best fast-start NGCCs can operate the HRSG and steam turbine within 30 to 45 minutes of a "cold-start" firing the combustion turbine, EPA, *Efficient Generation: Combustion Turbine Electric Generating Units—Technical Support Document (TSD)*, Dkt. No. EPA-HQ-OAR-2023-0072-0060, 25–26 (May 2023), https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0060/content.pdf, whereas simple cycle CTs can achieve startup within a matter of minutes.

[19] *See id.* at 25–26. *See also, e.g.*, Modern Power Systems, *Flexibility – the new battleground*, https://www.modernpowersystems.com/news/newsflexibility-the-new-battleground/ (last visited Aug. 6, 2023); John Gülen*, Gas Turbine Combined Cycle Fast Start: The Physics Behind the Concept*, POWER ENGINEERING, June 12, 2013, https://www.power-eng.com/coal/gas-turbine-combined-cycle-fast-start-the-physics-behind-the-con/#gref; Siemens Energy, *From Base to Cycling Operation: Innovative Operational Concepts for CCPPs* (presentation delivered to Power-Gen Europe 2015 in Amsterdam, Netherlands, June 11–15, 2015), https://assets.siemens-

Despite this, EPA's proposal would broadly permit the operation of new CTs not only for peaking needs, but for intermediate-load applications as well. Intermediate-load (also known as load-following) EGUs typically operate "during the mid-morning to evening hours but [are] turned off or ramped down significantly during the night and early morning hours."[20] Thus, while these units often do not run around the clock like baseload EGUs, they frequently operate for at least half of the day and are likely to start and stop far less frequently than peaking or low-load EGUs. According to data maintained by EPA's Clean Air Markets Program Database (CAMPD), nearly 70 percent of electricity from gas-fired combustion turbines operating between 1,250 and 4,500 hours last year (the approximate range of most intermediate-load units) came from combined cycle EGUs.[21]

Yet despite the fact that combined cycle units already provide the majority of intermediate-load generation to the grid, EPA has determined that the "*best* system of emission reduction" for intermediate-load turbines is simple cycle technology. Even "new and clean," state-of-the-art simple cycle turbines typically emit one-third more CO_2 per MWh (and in some cases considerably more) than comparably sized new combined cycle units. EPA's selection of simple cycle CT technology as the baseline BSER for a generation function that NGCCs are already primarily serve units is puzzling.

In the rule preamble, the agency's rationale for setting simple cycle technology as the BSER for intermediate-load units is exceedingly brief:

> The EPA considered but is not proposing combined cycle unit design for combustion turbines in the intermediate subcategory because the capital cost of a combined cycle EGU is approximately 250 percent that of a comparable-sized simple cycle EGU and because the amount of GHG reductions that could be achieved by operating combined cycle EGUs as intermediate load EGUs is unclear. Furthermore, intermediate load combustion turbines start and stop so frequently that there might not be sufficient periods of continuous operation where the HRSG would have sufficient time to generate steam to operate the steam turbine enough to significantly lower the emissions rate of the EGU.

88 Fed. Reg. at 33,287. These assertions are in direct conflict with the facts on the ground. First, EPA's unsupported claim that the capital costs of a combined cycle units are 250 percent that of a comparable simple cycle turbine is dramatically off the mark. We analyzed four recent reports on combustion turbine costs and found that in three of those studies, overnight capital costs for new combined cycle units were *lower* on a per-kilowatt basis than for new simple cycle turbines in some or all of the scenarios presented. And the fourth study showed a far smaller cost differential between NGCCs and CTs than EPA has imagined.

---

energy.com/siemens/assets/api/uuid:0cb3c09d-3464-4d29-8cfe-055b7b5dee32/t6s2p2-powergeneurope2015-base-to-cycling.pdf, included as Exhibit 1.

[20] *See Energy KnowledgeBase*, Intermediate Load, https://energyknowledgebase.com/topics/intermediate-load.asp (last visited Aug. 2, 2023).

[21] These data were accessed through a CAMPD query.

The most recent (and most conservative) report is the National Renewable Energy Laboratory 2023 Annual Technology Baseline (ATB), published in June of this year.[22] The ATB report shows the overnight capital costs of F-frame gas-fired combustion turbine in 2023 to be $995/kW. The reported overnight capital costs for F-frame combined cycle units are $1,105–$1,109/kW, while the costs for H-frame combined cycle units are $1,134–$1,141/kW. Far from 250 percent, the average cost of a new combined cycle unit vis-à-vis a simple cycle unit of equal capacity is no more than 114 percent and is as little as 110 percent. While the costs of more efficient aeroderivative turbines (which were not provided by NREL) would be higher than frame turbines, this would be true for both simple cycle and combined cycle units. In fact, the percentage cost differential between aeroderivative CTs and NGCCs would likely be *smaller* than for frame turbines, since the main cause of that delta—the cost of the HRSG—would be a smaller proportion of overall costs.

The other three analyses show even more favorable cost numbers for combined cycle compared to simple cycle units. A 2019 study prepared by Sargent & Lundy for EIA showed a similar per-kilowatt hour cost comparison between NGCC and CT units, with combined cycle EGUs having *lower* overnight costs than simple cycle units in a number of scenarios.[23] A 2019 analysis by the California Energy Commission (CEC) found lower per-kilowatt overnight capital costs for combined cycle EGUs in most instances relative to simple cycle turbines, with the mid-case NGCC estimates ranging from $890 to $914/kW and the mid-case CT estimates ranging from $971 to $1,190/kW.[24] Comparing levelized costs of electricity, CEC reported mid-case combined cycle estimates of $118–$119/MWh and mid-case simple cycle estimates ranging from $409 to $746.[25]

Finally, a 2018 study prepared for PJM by the Brattle Group and Sargent & Lundy found that the overnight capital costs of a new 2x1 combined cycle equipped with GE 7HA.02 combustion turbines ranged from $772 to $883/kW while the costs for a new simple cycle unit, also using a GE 7HA.02, ranged from $799 to $898/kW.[26] The study notes that

---

[22] Nat'l Renewable Energy Laboratory, *Related Datasets 2023 Annual Technology Baseline (ATB) Cost and Performance Data for Electricity Generation Technologies*, 2023_v1_Workbook_06_28_23.xlsx (tab titled "Natural Gas_FE"), https://data.openei.org/files/5865/2023%20v1%20Annual%20Technology%20Baseline%20Workbook%20Original%206-28-2023%20(1).xlsx, included as Exhibit 2.

[23] Sargent & Lundy Consulting, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, Table 2—Cost & Performance Summary Table (Dec. 2019), https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf, included as Exhibit 3.

[24] Cal. Energy Comm'n, E*stimated Cost of New Utility-Scale Generation in California: 2018 Update*, Table B-25 (May 2019), https://www.energy.ca.gov/sites/default/files/2021-06/CEC-200-2019-005.pdf, included as Exhibit 4.

[25] *Id.*

[26] The Brattle Group/Sargent & Lundy Consulting, *PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date*, Table 9: Plant Capital Costs for CT Reference Resource in Nominal $ for 2022 Online Date and Table 10: Plant Capital Costs for CC Reference Resource in Nominal $ for 2022 Online Date (Apr. 19, 2018) https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx, included as Exhibit 5.

> while the capacity of the [NG]CCs plants has almost *doubled* compared to that in the 2014 CONE Study, the cost of the gas turbines increased by 50%, and the cost of the steam section of the [NG]CC (including the heat recovery steam generator and steam turbine) increased by only 30%. CT plants share the same economies of scale on the combustion turbine itself, but not the greater economies of scale that [NG]CCs enjoy on their steam section or other balance of plant costs.[27]

The data from each of the four reports are presented in the table below.

Table 1: Comparison of NGCC and CT Overnight Capital Cost Estimates

Source of cost estimate	**Combined cycle unit – capacity/heat rate**	**Capital cost ($/kW)**	**Simple cycle unit - capacity/heat rate**	**Capital cost ($/kW)**
NREL (2023)	F Frame- 727 MW/ 6363 Btu/kWh H Frame- 992 MW/ 6196 Btu/kWh	$1105–09 $1134–41	F Frame- 233 MW/9,717Btu/kWh	$995
EIA AEO (Sargent & Lundy) (2019)	GE 7HA.02 2x2x1- 1083 MW/6370 Btu/kWh H Class 1x1x1- 418 MW/6431 Btu/kWh	$958 $1084	2 x LM 6000- 105 MW/9124 Btu/kWh 1x GE 7FA- 237 MW/9905 Btu/kWh	$1175 $713
Cal Energy Comm'n (2019)	640 MW/7250 Btu/kWh 700 MW/7250 Btu/kWh	$914 (mid-case) $890 (mid-case)	NextGen LM6000- 49.9 MW/10,585 Btu/kWh 2 x NextGen LM6000- 100 MW/10,585 Btu/kWh 200 MW/9880 Btu/kWh	$1190 (mid-case) $1185 (mid-case) $971 (mid-case)
PJM (The Brattle Group/Sargent & Lundy) (2018)	GE 7HA.02 2x1- 1140 MW/~6300 Btu/kWh	$772–873	GE 7HA.02- 320 MW/~927- Btu/kWh	$799–898
Average of Studies		**$988**		**$1011**

[27] *Id.* at 52–53 (emphasis in original).

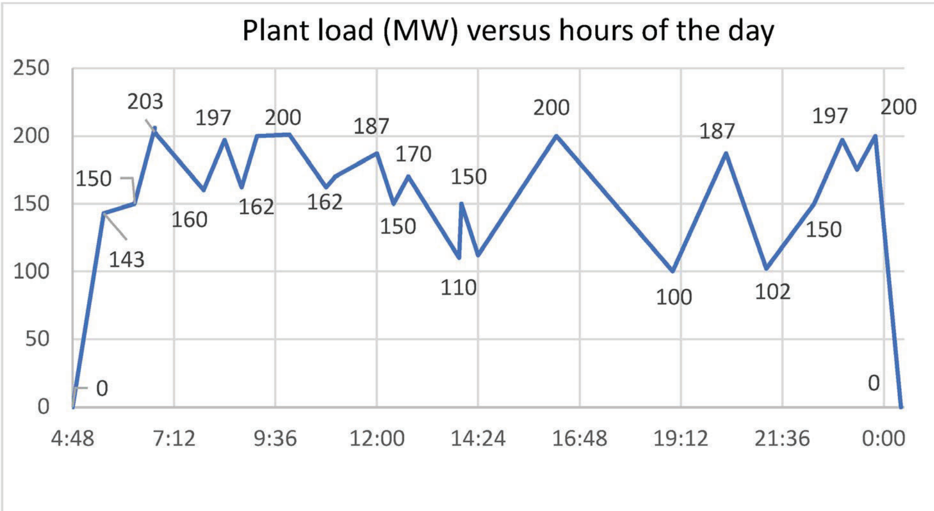
EPA's assertion that a new combined cycle units capital costs are two-and-a-half times those of comparably sized simple cycle turbine is thus flatly wrong: the average of the studies cited above indicate that NGCCs are *cheaper* on a per-kW basis than CTs.

EPA's second assertion that "the amount of GHG reductions that could be achieved by operating combined cycle EGUs as intermediate-load EGUs is unclear" makes little sense. It is an undisputed fact that combined cycle technology is far more efficient than simple cycle technology and produces far lower emissions for the same quantity of electricity generated. This is apparent even from the performance of the current fleet of gas turbines, which includes many old units and obsolete plant designs and does not fully reflect the greater efficiency of today's best NGCCs. As noted above, close to 70 percent of all intermediate-load generation in 2022 was provided by existing (and, in many cases, aging) combined cycle facilities.[28] These EGUs' emissions rates were approximately 20 percent lower than those of the simple cycle units that also operated between 1,250 and 4,500 hours per year.[29] Again, for "new and clean" EGUs using the best technology available today, this differential would be much higher. Although hours of operation are not a perfect proxy for intermediate-load operation, these figures leave little doubt that, even for an aging fleet, combined cycle generation provides significantly lower emissions for intermediate-load operation than simple cycle generation.

Finally, EPA claims that "intermediate load combustion turbines start and stop so frequently that there might not be sufficient periods of continuous operation where the HRSG would have sufficient time to generate steam to operate the steam turbine enough to significantly lower the emissions rate of the EGU." 88 Fed. Reg. at 33,287. If this were true, then the data presented above would look very different, rather than reveal a 20 percent gap in emission rates even with considering older, less efficient combined cycle models rather than the far more efficient units now available. Furthermore, frequent starting and stopping is not characteristic of intermediate-load units, which typically run from mid-morning until evening and then ramp down or turn off at night. The figure below depicts the typical operation of an intermediate-load combined cycle unit over the course of the day. While its load indeed fluctuates, the unit does not start and stop frequently, as EPA suggests, but instead only shuts off entirely for approximately five hours when demand is lowest.

[28] These data were accessed through a CAMPD query.
[29] *Id.*

Fig. 2: Daily Load Pattern of Intermediate-Load NGCC Unit[30]



EPA's selection of simple cycle technology as the BSER for intermediate-loads units does not hold up in the face of this analysis, particularly in light of the fact that the agency has not provided a cost-effectiveness or technical analysis to support its decision. Of course, the options for gas-fired generation vary widely in efficiency, and the more efficient units employ more sophisticated technologies and materials and may have a higher capital cost for similarly sized facilities (although the CEC, Brattle Group, and S&L studies suggest that this is often *not* true when comparing across CTs and NGCCs). Yet capital costs are only one part of the picture: cost-effectiveness—which EPA traditionally evaluates in setting the BSER—depends not only on an estimate of different options' capital costs, but also future gas prices, utilization of the unit over a period that spans decades, and—critically—the value of the pollution abated as a result of those expenditures.

It may well be the case that an operator is reluctant to pay a higher initial cost to achieve a higher efficiency, even if the costlier upfront investment is fully justified from an environmental (and, in some cases from a purely economic) standpoint. Additionally, capital cost considerations may dominate an operator's decision in regulated markets that allow it to pass through fuel costs to customers, making efficiency a secondary consideration. Yet if facility owners' perceptions of their own economic interests were the driving factor of environmental policy, there would be no need for regulation in the first place. This is precisely why EPA's argument based on capital costs would fall short *even if it were correct* (which, in most cases, it is not): it substitutes the short-term thinking of a plant operator with the longer-term thinking needed for EPA to properly serve the public interest and fulfill its statutory duty.

As depicted above, the average of the four studies discussed above (NREL, EIA, CEC, and PJM) show lower overnight capital costs for NGCCs compared to CTs on a per-kW basis. Thus, any cost-effectiveness analysis based on that average would necessarily show that an operator's decision to

[30] Hiyam Farhat and Coriolano Salvini, *Novel Gas Turbine Challenges to Support the Clean Energy Transition*, 15 ENERGIES 5474, Fig. 7 (2022), https://doi.org/10.3390/en15155474, included as Exhibit 6.

construct and operate a new NGCC rather than a new CT would yield both net environmental benefits and net financial savings at every capacity factor. However, to understand how this calculus might play out under a conservative scenario, we compared the annualized costs and monetized CO_2 emissions of two new, comparably sized NGCC and CT units using the data from the NREL study, which were *least* favorable to NGCCs of those included in the table above. Our sources, assumptions, and methodology are described below.

Source of cost and emission assumptions:

- The cost of NGCC ($1,109/kW) and CT ($995/kW) generation capacity reflect overnight capital cost figures provided in NREL's ATB report.[31]
- Our assumed cost of gas ($3.69), amortization period (30 years), and annual interest rate (7 percent) match EPA's own assumptions from the proposed rule when determining the cost-effectiveness of the CCS component of the "best system" for baseload turbines. 88 Fed. Reg. at 33,298 n.340.
- For the capital recovery factor, we used Engineers Edge *Capital Recovery Formula and Calculator.*[32]
- CO_2 emission rates for comparably sized NGCC and CT units were based on 2021 CAMPD emission data for Bayonne Energy Center (Siemens SGT 600), Lordstown Energy Center (Siemens 600 SGT with HRSG) and Holland Energy Park (Siemens SGT 800 with Siemens SST 400 steam generator and HRSG), converted to net emission rates by a factor of 1.03.
- For the social cost of carbon, we used the federal Interagency Working Group (IWG) central estimate for 2035, which is $67/metric ton.[33]

[31] *See* n. 22, *supra*.

[32] Engineers Edge, *Capital Recovery Formula and Calculator*, https://www.engineersedge.com/calculators/capital_recovery_factors_15667.htm (last visited Aug. 3, 2023).

[33] Interagency Working Group on Social Cost of Greenhouse Gases, *supra* n. 6, at Table A-1. The IWG's values are highly conservative estimates that very likely underreport the true social harm that CO_2 emissions impose on society. *See, e.g.*, Inst. for Policy Integrity, et al., *Comments on the Consideration of the Social Cost of Greenhouse Gases in "Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles," 88 Fed. Reg. 29,184 (proposed May 5, 2023)*, 26, 30–32 (July 5, 2023), included as Exhibit 7. In addition, the Office of Management and Budget (OMB) recently proposed a new discounting protocol that would set the default discount rate for regulations at 1.7 percent. OMB, *Circular A-4: Draft for Public Review*, 75–76 (Apr. 6, 2023), https://www.whitehouse.gov/wp-content/uploads/2023/04/DraftCircularA-4.pdf. Calculations using a less conservative social cost of carbon (such as Resources for the Future's recommendation of $185/metric ton) or a lower discount rate would provide considerably more support for our argument that NGCC are both economically and environmentally preferable to CTs in the vast majority of applications. Kevin Rennert, et al., *Comprehensive evidence implies a higher social cost of CO_2*, 610 NATURE 687–692, https://www.nature.com/articles/s41586-022-05224-9, included as Exhibit 8.

Methodology:

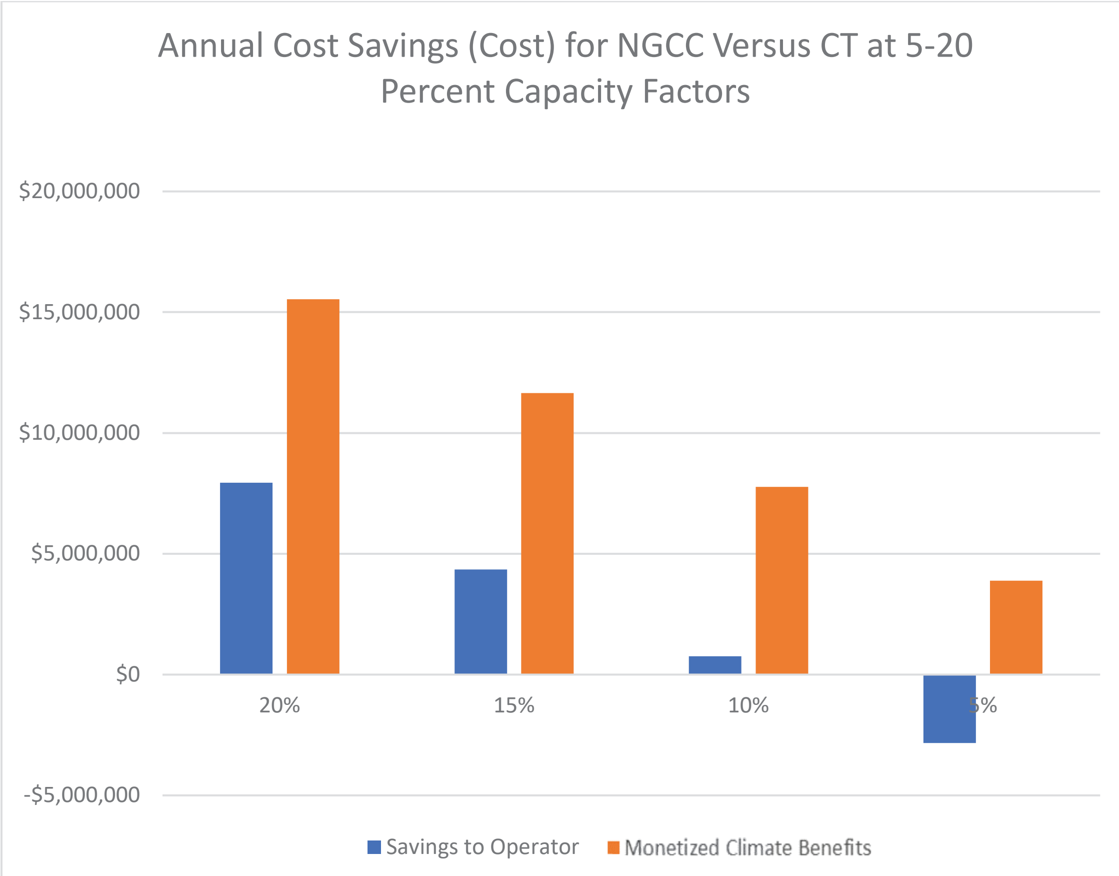
- Our analysis considered the relative cost-effectiveness of new CTs and NGCCs at four annual capacity factors: 20, 15, 10, and 5 percent. We evaluated two hypothetical units: one new CT and one new NGCC. Our hypothetical simple cycle unit consist of three 233 MW GE F-class combustion turbines with a total capacity of 699 MW, while our hypothetical combined cycle unit consists of two of the same GE turbines as well as an HRSG and gas turbine/generator, configured in a 2x1 arrangement, also with 699 MW of capacity. Although the NGCC evaluated in the NREL study was 727 MW in capacity, we normalized it to 699 MW to provide equivalent generation with the CT unit at each capacity factor, and thus allow for an apples-to-apples comparison.
- Our calculations produced five values for the two hypothetical units:
  - **Annual capital costs:** To calculate this figure, we multiplied NREL's per-kW overnight capital cost figures for new NGCCs and CTs by the respective generation capacities of our two hypothetical units. We then calculated an annualized cost figure for each facility, using EPA's assumptions of a 30-year amortization period and an interest rate of 7 percent.
  - **Annual fuel costs:** To determine the annual quantity of gas consumed by each unit, we divided each source's assumed emission rate in lb/MWh by the heat content of gas (115 lb/MMBtu), then multiplied the resulting quotient by each source's annual generation total at the capacity factor under evaluation. This calculation yielded each facility's total annual fuel consumption in MMBtu, which we multiplied by EPA's assumed cost of gas ($3.69/MMBtu) to determine annual fuel costs.
  - **Annual operator costs:** This column simply reflects annualized capital costs plus annual fuel costs. We did not account for annual operation and maintenance costs, but these are very small, and thus effectively trivial, in comparison to capital and fuel costs.
  - **Annual CO_2 emissions:** This figure represents each unit's assumed emission rate, which, as noted above, reflects in-use CAMPD data for comparable NGCC and CTs, multiplied by the unit's capacity, 8,760 hours per year and the annual capacity factor under evaluation.
  - **Annual social cost of CO_2 emissions:** To calculate this figure, we converted each unit's annual CO_2 emissions to metric tons and multiplied that figure by $67/metric ton, the IWG's 2035 social cost of carbon at a 3 percent discount rate.

The calculation results are presented below. The figures highlighted in orange reflect the overall economic benefit of operating the NGCC unit rather than the CT as well as the monetized climate benefit.

Table 2: Cost-Effectiveness Comparison of Comparable Combined Cycle and Simple Cycle Units

	Overnight capital costs	Fuel costs	Operator's cost	CO_2 emissions (mt)	Social cost of CO_2 emissions
20% Capacity Factor					
3 F-class CTs (699 MW)	$56,050,748	$48,375,179	$104,425,927	758,579	$52,341,964
F-class 2x1 NGCC (727 MW)	$62,472,643	$34,013,797	$96,486,440	533,376	$36,802,944
Incremental Benefit for NGCC	-$6,421,895	$14,361,381	$7,939,486	225,203	$15,539,021
15% Capacity Factor					
3 F-Class CTs (699 MW)	$56,050,748	$36,281,384	$92,332,132	568,934	$39,256,473
F-Class 2x1 NGCC (727 MW)	$62,472,643	$25,510,348	$87,982,991	400,032	$27,602,208
Incremental Benefit for NGCC	-$6,421,895	$10,771,036	$4,349,141	168,902	$11,654,265
10% Capacity Factor					
3 F-Class CTs (699 MW)	$56,050,748	$24,187,589	$80,238,337	379,290	$26,170,982
F-Class 2x1 NGCC (727 MW)	$62,472,643	$17,006,899	$79,479,541	266,688	$18,401,472
Incremental Benefit for NGCC	-$6,421,895	$7,180,691	$758,796	112,602	$7,769,510
5% Capacity Factor					
3 F-Class CTs (699 MW)	$56,050,748	$12,093,795	$68,144,543	189,645	$13,085,491
F-Class 2x1 NGCC (727 MW)	$62,472,643	$8,503,449	$70,976,092	133,344	$9,200,736
Incremental Benefit for NGCC	-$6,421,895	$3,590,345	-$2,831,549	56,301	$3,884,755

Fig. 3: Net Economic and Environmental Benefits of Combined Cycle Operation Relative to Simple Cycle Operation



The data provided above are stark: under the 20, 15, and 10 percent capacity factor scenarios, combined cycle operation is far more environmentally beneficial compared to simple-cycle operation *and* more economically advantageous to operators and ratepayers, as the savings in fuel costs resulting from the NGCC's superior efficiency exceed its additional capital costs in each case. Only under the 5 percent capacity factor scenario do the ratepayers see higher costs as a result of combined cycle operation, and yet even then, the social benefits of reduced CO_2 emissions outweigh those economic disbenefits.

Given the clear economic and environmental advantage of operating combined cycle unit even at low capacity factors, one may wonder why so many existing simple cycle units nonetheless continue to operate at levels above single-digit capacity factors. There are two basic answers to this. First, because simple cycle units invariably have higher marginal operating costs than combined cycle facilities, a given CT will only be called upon to dispatch when all of the available NGCCs in a given load-balancing area are already up and running. Second, a large portion of the combined cycle fleet was constructed approximately 20 years ago, when fast-start NGCCs—which are far superior to older, conventional NGCCs to use for peaking purposes and operating at lower capacity factors—were not available. Thus, simple cycle units have provided much of the generation at lower capacity factors, and have operated at higher capacity factors when combined cycle generation has been effectively maxed out in a given service area.

This is a description of how the gas fleet has operated for the last two decades given the economic and technical factors from 20 years ago. Yet in this rule proposal, EPA is determining what to require for combustion turbines *going forward*. The purpose of section 111(b) standards is not simply to accommodate the practices that the industry currently follows. On the contrary, it is designed as a "technology-forcing" provision. As the D.C. Circuit has held, "EPA does have authority to hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible and will produce the improved performance necessary to meet the standard." *Sierra Club v. Costle*, 657 F.2d 298, 364 (D.C. Cir. 1981). The data above show that it is not just feasible but advantageous to require combined cycle technology for units operating at capacity factors considerably lower than 20 percent, and certainly at whatever range EPA ultimately selects for intermediate-load units.

B. EPA Must Reduce the Annual Capacity Factor Threshold Distinguishing Low-Load and Intermediate-Load Operation From 20 Percent to No More than 5 to 8 Percent and 15 Percent on a Monthly Average Basis.

The subsection above demonstrates that EPA's decision to establish simple cycle technology as a component of the "best system" for intermediate-load units is unsupported, and that combined cycle technology is the appropriate designation for that subcategory. The data also strongly called into question EPA's decision to set the cut-point separating the low-load from intermediate-load combustion turbine subcategories at an annual capacity factor as high as 20 percent. This 20 percent threshold does not correspond to actual peaking operations, and EPA's selection of simple cycle generation as the "best system" is only justified for units that operate at capacity factors of no more than 5 to 8 percent. Accordingly, to the extent that EPA retains simple cycle technology as the BSER for low-load units, it must limit that subcategory to units operating at those capacity factors and lower.

It is important to observe here that EPA has not proposed an output-based emission standard for new low-load combustion turbines. Instead, it establishes an input-based standard ranging from 120 to 160 pounds of CO_2 permitted for each MMBtu of heat input. Yet 120 lb/MMBtu figure—which applies to units that "derive[] [their heat input] from natural gas," 40 C.F.R. § 60. 60.5525a(a)(2)—simply reflects the CO_2 content of standard gas itself. 88 Fed. Reg. at 33,259. This leads to what is, in practice, a regulatory tautology: units that derive their heat input from gas must, to meet the standard, burn gas. And the looser standard of 160 lb/MMBtu figure, which applies to units other than those firing gas, corresponds to the CO_2 content of petroleum products such as diesel or distillate fuel oil, *id.*—again, the very fuels that these sources would be firing in any event if they were not firing gas.

Therefore, EPA's proposed standards for low-load units will not achieve any emission reductions beyond business-as-usual. As discussed below, the agency should reformulate these standards as output-based emission rates based on the most efficient technologies available for that operational mode. Regardless of how EPA formulates this standard, it will likely to determine that these units' low frequency of operation rules out the more aggressive CCS and hydrogen emission reduction techniques that the agency has included in the "best system" for intermediate-load and baseload turbines. However, there is a substantial difference in performance between aeroderivative CTs, such as the LM Series, SWIFTPAC Series and SGT Series units, and others on the market. EPA should establish an "ISO new and clean" limit to ensure that only the most efficient units are purchased and an in-use operating limit, based on the performance of these units, rather than older, less efficient designs. We describe this approach in more detail, and propose emission rates based on it, in the following subsection.

But even the most state-of-the-art CTs are far less efficient, and thus emit much more CO_2, than fast-start NGCCs, which can operate effectively on short-notice and thus meet load-following operational needs. For this reason, it is all the more critical from an environmental perspective that EPA limit the low-load subcategory to the greatest extent possible and take pains to ensure that it does not encompass anything other than true peaking units. The current upper limit of a 20 percent annual capacity factor is far too high to prevent inefficient CTs from being used as seasonal baseload units (a phenomenon we discuss more below), and would include in this largely uncontrolled category a large number of units that can and should be expected to achieve much lower emission rates.

In the preamble, EPA describes its selection of simple cycle technology as the BSER for low-load operations using largely the same justifications it deployed with respect to the intermediate-load subcategory:

> The EPA expects that units in the low load subcategory will be simple cycle turbines. The capital cost of a combined cycle EGU is approximately 250 percent that of a comparable sized simple cycle EGU and would not be recovered by reduced fuel costs if operated as low load units. Furthermore, low load combustion turbines start and stop so frequently that there might not be sufficient periods of continuous operation for the HRSG to begin generating steam to operate the steam turbine enough to significantly lower the emissions rate of the EGU.

88 Fed. Reg. at 33,286. In the previous subsection, we explained how EPA's assumptions about the relative capital costs of CTs and NGCCs badly misses the mark, and that that NGCCs operating at 20, 15, and 10 percent capacity factors—and somewhat lower still—*could* recover those additional capital costs through conserved fuel. More importantly, ensuring that an operator pays no additional money to achieve pollution reductions *is not the legal standard of section 111.* The agency acts as though *any* quantity of compliance costs are unacceptable if an operator cannot fully defray them through operational savings. Yet in *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999), the D.C. Circuit held that EPA must only ensure that the costs of its standards are not "exorbitant." Similarly, in *Portland Cement Ass'n v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975), the court held that the regulatory costs of the BSER must not be "greater than the industry could bear and survive."

Furthermore, by foreclosing an environmentally superior control option merely because it would entail *some* additional capital costs that an operator cannot fully recoup, EPA unlawfully and arbitrarily treats costs as determinative of the "best system," ignoring the other statutory factors such as the amount of pollution reduced. The statute requires EPA to balance these different factors, not to prioritize one over all the others. For this reason, EPA typically determines whether section 111 costs are reasonable not by considering them in isolation, but by calculating the dollars an operator must spend to reduce each ton of pollution. As discussed previously, even using the most conservative capital cost estimates, the monetized CO_2 benefits of constructing and operating an NGCC rather than a CT outweigh any additional compliance costs even at the lowest capacity factor analyzed.

As for frequent starts and stops, EPA has not shown that fast-start NGCCs cannot fill this need; it assumes, without further analysis, that only CTs can. As demonstrated above, though, modern NGCCs can meet this need as well. In fact, EPA's own Technical Support Document *titled Efficient Generation: Combustion Turbine Electric Generating Units* makes this exact point:

> Improving startup time of combined cycle EGUs makes combined cycle EGUs a more dependable power source for load-following supply, and research/practice suggests several ways to improve combined cycle startup times. Combustion turbines operating as EGUs in a combined cycle system have historically been designed to operate for extended periods of time at steady loads. Since these combined cycle EGUs were not intended to start and stop on a regular basis, they had relatively long startup times depending on unit-specific factors and whether startup was initiated from a cold, warm, or hot state. During the past decade, the demands placed on this conventional mode of steady, base load operation have changed. The latest combined cycle EGUs are designed with advanced technology and features to be more flexible and respond faster to increased demand for reliable electricity, support increased generation from intermittent sources (*i.e.*, renewables), capitalize on financial incentives to improve dispatch or supply non-spinning reserves, operate at higher efficiencies, and emit less pollution. As a result, advanced fast-start, combined cycle EGUs incorporate multiple techniques that allow the EGU to start and stop faster, cycle output faster, and maintain higher part-load efficiencies than previous designs.
>
> Several combustion turbine manufacturers market complete combined cycle systems that can ramp up to full load from a cold start in less than an hour, depending on unit-specific factors. Advanced combustion turbines, when isolated from the HRSG and steam turbine, can reach full load at full speed as a simple cycle (*i.e.*, Brayton) unit in less than 20 minutes. When adhering to some of the following fast-start techniques, the HRSG, steam turbine, and balance of plant equipment can reach safe operating temperatures and pressures and begin generating additional electricity within 30 to 45 minutes of ignition of the combustion turbine. Techniques that can be used to reduce startup times for combined cycle systems are discussed below.[34]

Our primary objection here is that EPA has defined its low-load peaking category far too broadly, and in doing so, will allow CTs to operate at much higher frequencies than they should given the availability of fast-start NGCCs. The agency bases the 20 percent capacity factor cut-point between its low- and intermediate-load subcategories on two factors. First, it asserts that simple cycle turbines exhibit variable emission rates at lower loads, and so it is difficult to establish a single output-based

[34] EPA, *supra* n. 18, at 25.

limit (which is appropriate for intermediate-load units) that would accommodate the range of sources operating in those thresholds. 88 Fed. Reg. at 33,321. Second, it claims that two-thirds of simple cycle units constructed in recent years have operated above a 10 percent capacity factor, and that some of these units would have difficulty complying with an intermediate-load standard. *Id.* The agency solicits feedback on capacity factors ranging from 15 to 25 percent as the appropriate threshold, but is ostensibly not considering capacity factors below 15 percent based on these two considerations. *Id.*

EPA's reasoning suffers from both legal-conceptual and empirical flaws. On a conceptual level, the agency again treats section 111(b) as a technology-following rather than technology-forcing provision, failing to appreciate that "section 111 looks toward what may fairly be projected for the regulated future, rather than the state of the art at present." *Nat'l Asphalt Pavement Ass'n v. Train*, 539 F.2d 775, 785 (D.C. Cir. 1976) (cleaned up). That some newly constructed simple cycle units have, during periods of low gas prices, operated at capacity factors between 10 and 15, or between 10 and 20 percent, does not mean that EPA cannot hold the industry to a stricter standard, particularly given the advantages that combined cycle units have over simple cycle units even at low usage rates.

On a purely factual level, EPA's 20 percent threshold does not accurately reflect levels of operation associated with peaking generation. For example, the New England Independent System Operator defines a peaking unit as follows:

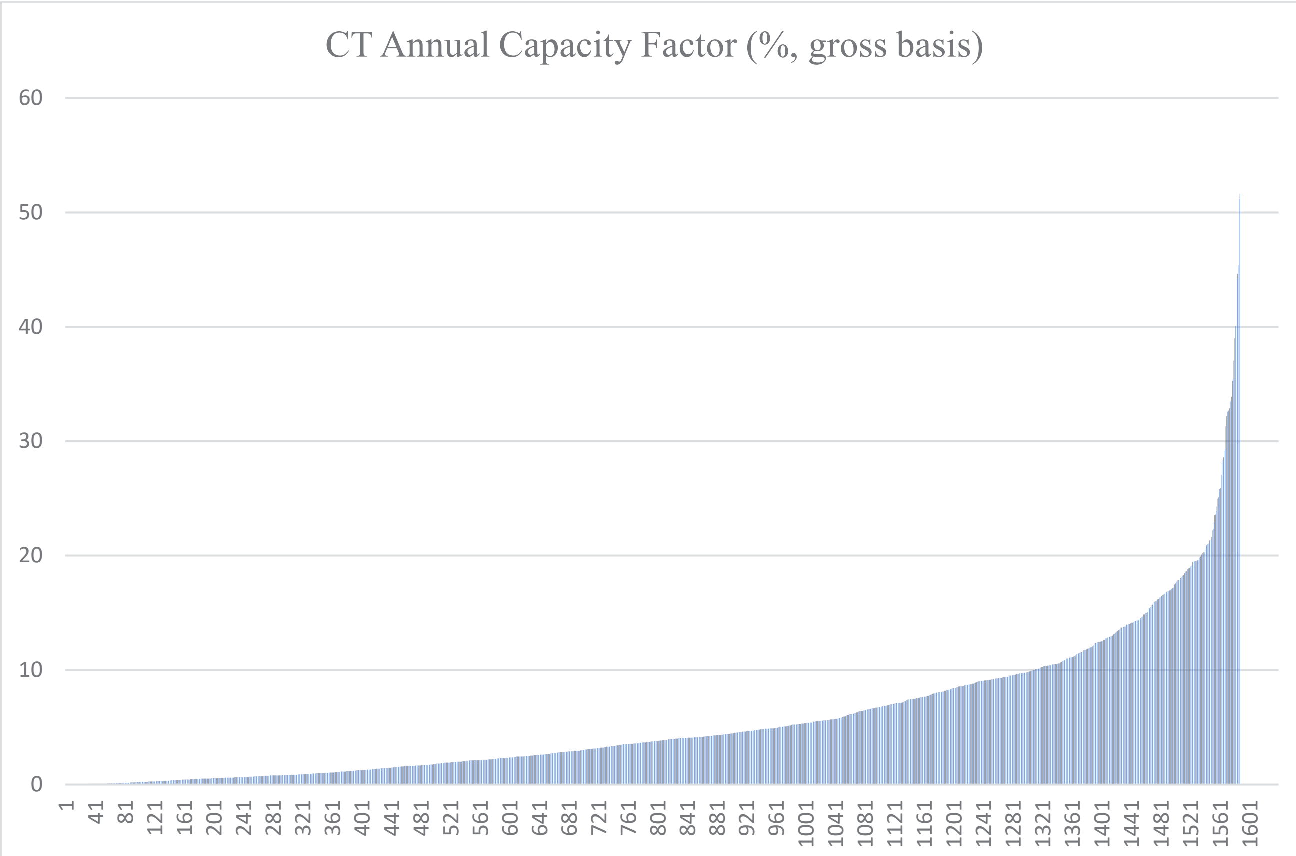
> A generating unit usually on line to meet power system requirements during very high, peak-day load periods when the demand on the system is the greatest and that may be used in response to system contingencies because they can start up quickly on demand and operate for only a few hours; typically operates less than 10% of the year (i.e., a few hundred hours per year) and at a relatively high cost (i.e., when the price of electric energy is high).[35]

General Electric, one of the largest manufacturers of gas-fired turbines, cites the American National Standards Institute[36] definition of peak load operation as 1,250 hours per year with five hours per start.[37] Indeed, EPA's own data reveal that over 70 percent of existing CTs already run at capacity factors below 8 percent:

---

[35] ISO New *England, Glossary and Acronyms* (definition of "peak-load generating unit, peaking unit), https://www.iso-ne.com/participate/support/glossary-acronyms/ (last visited Aug. 2, 2023).
[36] The American National Standards Institute is a private nonprofit organization that oversees the development of voluntary consensus standards for products, services, processes, systems, and personnel in the United States.
[37] *See* General Electric, *GE Gas Turbine Performance Characteristics,* GE Power Systems Publication GER-3567H, 14 (Oct. 2000), https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/resources/reference/ger-3567h-ge-gas-turbine-performance-characteristics.pdf, included as Exhibit 9.

Fig. 4: 2021 CT Capacity Factors by Unit[38]



The California Energy Commission report referenced above similarly demonstrates the capacity factors at which simple cycle units generally operate.

[38] This chart reflects data from EPA, *Technical Support Document: Simple Cycle Stationary Combustion Turbine EGUs - Supporting Data*, Dkt. No. EPA-HQ-OAR-2023-0072-0046, Attachment 1, Figs. 4, 5, and 6 (May 2023), https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0046. EPA's analysis included in this TSD is flawed in that it looks at each unit's highest utilization over a 10-year period. This results in a level of overall generation that is higher than was experienced by the group as a whole in any year. It is also worth noting that this data set covers CTs above 25 MW; if it were not so limited, it would likely show a much smaller percentage still of units operating at high capacity factors.

Table 3: California Energy Commission's Assumed Capacity Factors for New Combustion Turbine Designs[39]

Technology	Owner	Assumed Capacity Factor		
		Mid Case	High Case	Low Case
Conventional CT (both sizes)	Merchant	4.0%	1.5%	8.0%
	POU	4.5%	1.5%	7.5%
	IOU	4.0%	1.0%	7.0%
Advanced CT	All Owners	7.0%	4.0%	10.0%
Conventional CC	All Owners	57.0%	40.0%	71.0%
Conventional CC w/Duct Burners	All Owners	57.0%	40.0%	71.0%

Note: High and low are based on cost implications, not on the specific value of the capacity factor.

The CEC data indicate that the typical capacity factors for simple cycle (and, thus, most peaking) units are nowhere near 20 percent—let alone intermediate-load ranges—but are in the range of 1 to 10 percent range.

Furthermore, a peaking subcategory based on annual capacity factors above 5–8 percent will cover units that, in practice, do not operate as peakers. The Zion Energy Center in Zion, Illinois provides a clear example of this. This facility consists of three 198.9 MW GE simple cycle turbines that the company describes as "peaking units."[40] These units operate only sparingly other than in the summer, with annual capacity factors of 13.42 percent and annual emission rates of 1,240 lb/MWh.[41] Because they fall well below EPA's capacity factor threshold for the low-load/peaking subcategory, all three units in the plant would, if new, be effectively exempt from any emission reduction requirements under EPA's proposal beyond BAU. Consider, however, Figures 5 and 6 below, which depict the hourly load pattern for Zion Unit One in the summer of 2020. The operational data for this unit reveal few cold starts (which would be necessary for peaking application) and show that, for the vast majority of the hours during that summer, Zion's hourly gross load fell within a narrow band between 156 MW and 169 MW. A better description of the function of this unit might therefore be "seasonal baseload" or at least "seasonal load-following."

[39] Cal. Energy Comm'n, *supra* n. 24, at Table B-19: Estimated Capacity Factors for Natural Gas Technologies. The Commission based these assumptions on the historical monthly data it received through its Quarterly Fuel and Energy Report.

[40] Calpine, *Zion Energy Center*, https://www.calpine.com/zion-energy-center (last visited Aug. 2, 2023).

[41] This figure, as well as all data for Zion Energy Center and the figures and table depicting those data, were accessed through a CAMPD query.

Fig. 5: Zion Energy Center Unit One, Hourly Gross Load—June 1, 2020–August 31, 2020

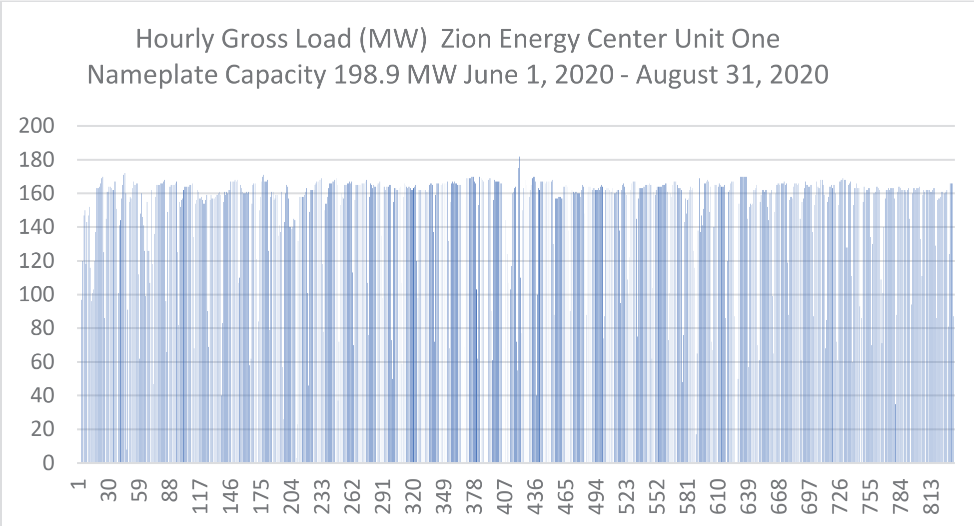
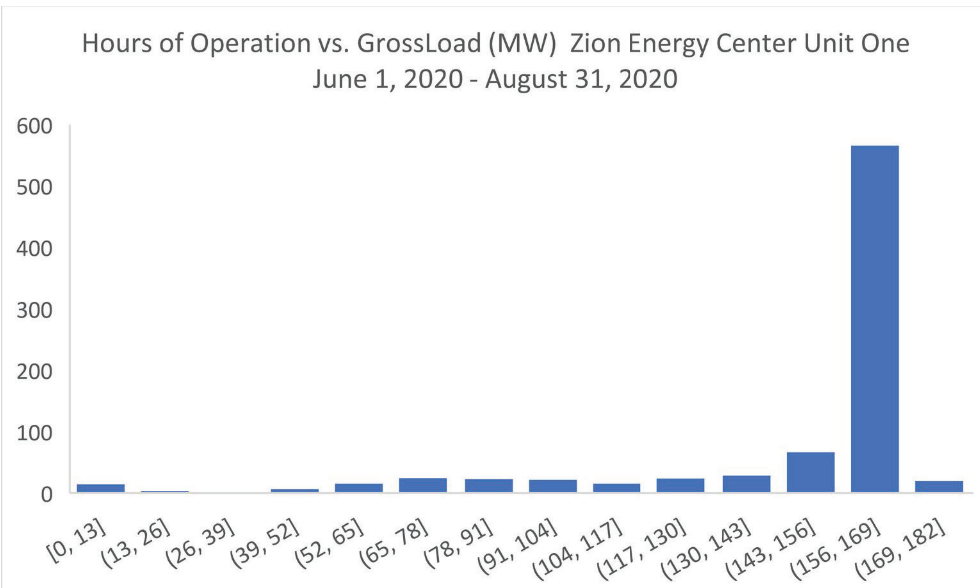
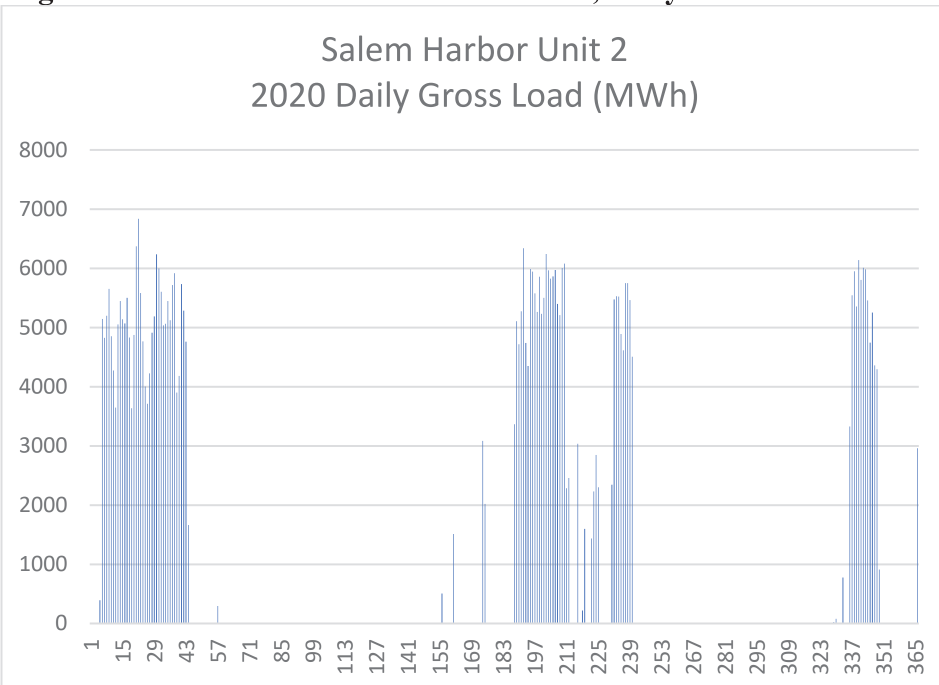


Fig. 6: Zion Energy Center Unit One, Histogram–Hours of Operation within Load Bin (MW)



Simply put, this is not a peaking unit. From both environmental and technical standpoints, there is no justification to operate a simple cycle unit in this manner; the load of Zion Unit One and its two sister CTs could and should be served by a combined cycle facility. An example of such a facility is Salem Harbor Power Station Unit 2, which is a 1x1 fast-start combined cycle generator. As shown in the figure below, this unit operates seasonally, meeting load in much of the winter and summer and turning off during other times.

Fig. 7: Salem Harbor Power Station Unit 2, Daily Gross Load in 2020



Thus, even while combined cycle operation is both demonstrated and superior for seasonal operations of this nature, plants like Zion would, under the Proposed Rule, receive a free pass to perform baseload functions during significant swathes of the year and emit essentially unchecked amounts of CO_2. The table below contrasts Zion Unit One's 2020 emissions performance (along with two other CTs that operated in a similar manner) with Salem Harbor Unit 2 in that year:

Table 4: Operating Hours and Performance of "Seasonal" CTs vs. Intermediate-Load NGCC

Unit	2020 Operating Hours	2020 Emission Rate (lb/MWh)	Model	Design
Zion Unit One CT	1634	1240	GE	[data not available]
Ecton Two CT	2520	1329	GE 7FA	Frame CT
Antelope CT	1790	1198	GE7F.05	Frame CT
Salem Harbor Unit 2 NGCC	2142	857	GE 7F	GE FlexEfficiency 60

These data all point in one direction: EPA's 20 percent capacity factor threshold for low-load units—which, under the proposal, have effectively no emission reduction obligations—does not reflect true peaking applications. It would permit units that should have combined cycle technology to use inferior simple cycle configurations and is neither the optimal environmental nor economic selection. Consistent with the actual peaking operations, as well as the data provided in the previous section on the cost-effectiveness of different turbine designs, EPA should set the threshold for low-load units at no greater than 5 to 8 percent on an annual basis *and* 15 percent on a monthly average basis. These constraints are necessary to prevent CTs from operating in seasonal baseload or load-following applications (as demonstrated by Zion Unit One) or otherwise generating at frequencies far better suited for NGCCs.

The agency's claim that CTs experience variable emission rates below approximately 15 percent should be no barrier to this revised threshold. EPA's observation is limited to simple cycle turbines, but as demonstrated in the previous section of these comments, new combined cycle units are, in fact, more cost-effective to operate than new CTs down to capacity factors between 5 and 8 percent, and provide net environmental benefits at *all* capacity factors examined. Given the commercial availability of fast-start NGCCs and the standard definition of peaking operations as annual capacity factors of between approximately 5 to 8 percent, it is entirely reasonable for EPA to permit simple cycle CTs to operate at those levels and to expect NGCCs to operate above those levels.

Other critics may object on the ground that EPA must ensure sufficient gas-fired capacity that can dispatch so quickly (i.e., within 10 minutes) in the case of a large generating or transmission failure in the system that only CTs—and not even fast-start NGCCs—can serve this function. As discussed previously, fast-start NGCCs can, in emergency situations, bypass their HRSG and steam turbine and operate their gas turbines with a 10-minute startup time, bringing the steam components of the facility up to operational conditions afterwards. In any event, these facilities will rarely, if ever, have reason to run in this manner: as applied by grid operators, the need for 10-minute start-up capability is applicable to CTs *that will not normally operate*, but will instead sit idle in order to provide reserve capacity in the event of an emergency. These units will certainly not be operating more than 5 to 8 percent of the year in response to emergencies.

There is simply no justification for allowing simple cycle turbines to operate at capacity factors of above 5–8 percent annually and 15 percent monthly, and certainly not at annual factors exceeding 20 percent. As the data show, the vast majority of simple cycle units already run at very low frequencies, and combined cycle technology can easily accommodate all generation needs about the cut-points we recommended for low-load units. The agency must therefore designated NGCC technology as part of the "best system" for all units operating at capacity factors above those thresholds.

C. EPA Must Recalculate the Baseline Emission Reduction Rates for All Affected Combustion Turbines.

The changes to EPA's proposed combustion turbine standards that we urged in the previous sections would significantly affect the baseline (i.e., pre-CCS or hydrogen) emission rates that sources must achieve. Based on our recommendations, we have recalculated those rates, which appear in the table below. Our methodology starts by considering the "new and clean" ISO heat rates published by *Gas Turbine World.*[42] For the (newly contracted) low-load subcategory, we selected the emission rates of

[42] The International Organization for Standardization (ISO) heat rates published by *Gas Turbine World* are based on full rated output at 59°F (15°C) ambient air temperature, 14.7 psia seal level elevation, 60 percent relative humidity, no SCR, and no steam injection for load enhancement. *See* Gas Turbine World, *2022 GTW Handbook, Vol. 36*, 42 (2022). We employ EIA's published figure of

the fourth-most efficient large (>300 MW) and small (<300 MW) simple cycle combustion turbines. For the intermediate-load and baseload subcategories, we selected the heat rates of the fourth most-efficient large (>250 MW) and small (<250 MW) combined cycle units and converted those data to emission rates using standard conversion factors. These ISO rates would apply at the time of purchase,[43] thus ensuring that only the most efficient designs are employed.

Next, we compared the ISO rates for previous models with actual emissions data provided in CAMPD and concluded that turbines' in-use rates are approximately 22 percent higher than their "new and clean" rates. We thus multiplied those figures by a factor of 1.22 to establish a conservative estimate for in-use performance. We then provided an additional 4 percent performance margin for low-load and intermediate-load units and a 2 percent performance margin for baseload units. The final figures are as follows:

Table 5: Newly Calculated Baseline Performance Rates for Combustion Turbine Standards

Subcategory/unit size (MW)	ISO efficiency (percent) (net heat rate – (Btu/kWh))	ISO emission rate (lb CO_2/MWh (net))/in-use rate
Peaking units (<5–8% annual CP)		
<300 MW	41.3 (8302 [44])	970/1,280[45]
>300 MW	43.5 (7855)	920/1,210

117 lb CO_2 emitted per MMBtu of gas combusted to convert the published heat rates to emission limits.

[43] Project applicants would be required to provide vendor testing data documenting actual performance at ISO full load conditions. To the extent that EPA is concerned that differences in air pressure and temperature could benefit some sources' emission rates while disadvantaging others, it must not adjust the *entire* standard downward. Instead, the agency should implement a *unit-specific* adjustment factor for each source that accounts for temperature and pressure characteristics of the location in which it is situated.

[44] According to the *2022 GTW Handbook*, *supra* n. 42, the GE LMS 100 PA+ simple-cycle turbine is rated at 43.9 percent efficiency (7,773 Btu/kWh), which would suggest an emission limit of less than 1,050 lb/MWh (net). The GE/Baker Hughes LM 9000 claims an efficiency of "greater than 44 percent." Press Release, Baker Hughes, Baker Hughes LM9000 confirmed as world's most efficient simple cycle gas turbine after reaching key testing milestone for Arctic LNG 2 (June 9, 2020), https://www.bakerhughes.com/company/news/baker-hughes-lm9000-confirmed-worlds-most-efficient-simple-cycle-gas-turbine-after.

[45] The proposed efficiency and ISO emission rates are based on the figures published in the *2022 GTW Handbook* for the fourth best performer in the relevant size categories. The conversion from ISO ratings to emission limits is based on the emission rates accessed through a CAMPD query, with additional compliance margins of 2 and 4 percent for baseload and peaking units respectively.

Seasonal/intermediate-load units (>5–10% <40% annual CP)[46]		
<250MW	55 (6200)	725/955[47]
>250MW<500MW	60 (6000)	702/925
>500MW	63[48] (5416)	635/835
Baseload units (>40% annual CP)		
<250MW	55 (6200)	725/925
>250<500 MW	60 (6000)	702/870
>500 MW	63 (5416)	635/785

It is worth noting that we have identified an output-based CO_2 emission limit for low-load units, in contrast to EPA's proposed "clean fuel," input-based limits. The agency has expressed concern that CT emission rates are highly variable at capacity factors below around 15 percent, 88 Fed. Reg. at 33,321, concluding that the only practicable standard for such units is one based on CO_2 per unit of fuel input. Our methodology avoids this problem in three ways. First, we propose a "new and clean" ISO design standard based on the fourth-most efficient turbine design in today's market, rather than the single most efficient unit currently available or a design reflecting even greater efficiency improvements expected to occur over the next several years. Second, our 22 percent "in-use" factor—which reflects actual, historical emission rate variations—affords an additional compliance cushion that accounts for varying rates at low load. Finally, the additional 4 percent compliance allowance that low-load units receive (as do intermediate-load units) provides yet a third layer of compliance leeway. These three steps should address any concern that sources operating at low capacity factors cannot meet an output-based standard.

D. EPA Must Not Exempt New CTs Below 25 MW in Capacity from Regulation Under the Program.

EPA proposes to exempt small EGUs from the NSPS:

> To be considered an affected EGU under the current NSPS at 40 CFR part 60, subpart TTTT, the unit must meet the following applicability criteria: The unit must: (1) Be

[46] We base this 40 percent annual capacity factor cut-point separating intermediate-load from baseload units on analysis conducted by Clean Air Task Force and Natural Resources Defense Council. *See* Clean Air Task Force and Natural Resources Defense, *Comments 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*, 61, 64, 69 (Aug. 8, 2023).

[47] While ISO efficiencies are similar to those for baseload units, a higher emission limit for seasonal/load-following units is provided to reflect the increased cycling effects.

[48] GE and Mitsubishi offer large NGCCs with efficiency ratings at or above 64% (<5332 Btu/kWh), which would translate to an in-use emission limit of 775 lb/MWh. *2022 GTW Handbook, supra* n. 42.

> capable of combusting more than 250 million British thermal units per hour (MMBtu/h) (260 gigajoules per hour (GJ/ h)) of heat input of fossil fuel (either alone or in combination with any other fuel); and (2) serve a generator capable of supplying more than 25 MW net to a utility distribution system (i.e., for sale to the grid).

Proposed 40 C.F.R. §60.5509a(a)(2). The agency must delete this exemption and include these units in the program. EPA has a long history of regulating numerous classes of "smaller" sources that, as a group, generate harmful emissions. These include not only cars, motorcycles, trucks and buses,[49] but also lawn mowers, weed trimmers, and ice augers.[50] A 24.9 MW CT has potential CO_2 emissions of approximately 160,000 tons per year.[51] We estimate that there are now operating nearly 1,000 CTs that qualify for EPA's exemption. We know of no economic or technical barrier that would preclude EPA from establishing a performance standard for these units to ensure that they do not operate outside of their intended peaking mode.

While many of these EGUs are stand-alone units, many others are co-located with one, two, three, or more CTs, in some cases greatly exceeding the 25 MW in the aggregate. For example, the Narrows Generating Station is a floating "power barge" located in New York's Upper Bay between Brooklyn and Staten Island. This facility consists of 16 simple-cycle turbines, each 22 MW and thus below the applicability threshold, that together amount to 352 MW[52]—equal in capacity to many combined cycle units.

---

[49] *See generally* 40 C.F.R. Part 86.
[50] 73 Fed. Reg. 59,034, 59,035 (Aug. 8, 2008) ("We are adopting standards that will require manufacturers to substantially reduce emissions from marine spark-ignition engines and from nonroad spark-ignition engines below 19 kW that are generally used in lawn and garden applications.") (codified at 40 C.F.R. Part 1054).
[51] This figure assumes round-the-clock annual operation and an emission rate of approximately 1,450 lb/MWh, which is representative for CTs of this size.
[52] These data were accessed through a query to CAMPD.

Fig. 8: Photograph of Narrows Generating Station

Going forward, EPA should close this potential loophole and assure that any such co-located units are not treated differently with regard to their CO_2 emissions than otherwise identical facilities that have fewer—but larger—turbines and are thus subject to the rule's requirements. The agency must therefore (a) eliminate or dramatically lower the 25MW exclusion and (b) provide that where new small units located at units have a combined generating capacity greater than 25 MW, the performance standard for units greater than 25 MW applies.

Attachment B

Petitioners' Analysis of List of "Best-Performing" Simple-Cycle Combustion Turbines Provided in EPA's Efficient Generation TSD

FACILITY NAME	CT CONFIGURATION	CT Unit Capacity (MW)	Plant Capacity (MW)	In service date	Comment
Lonesome Creek	6 x GE LM6000 CT	(6) 60.5	363	2013-2021	
Topaz	10 x GE LM6000 CT	(10) 60.5	605	2021	
Octillo	5 x GE LMS 100 CT	(5) 162	810	2019	
Doswell	3 x GE 7FA.03 CT	(3) 187	1313	2 units 2019	4 x 122 MW CC ; 2 x 132 MW CC; 3 X 187 MW CT
Bayonne	8 x 64 + 2 x 66	64-66	644	2 units 2018	
Black Dog	1 x GE 7FA.05	(1) 238	563	2018	238 CT + 325 CC (2 units)
Mustang	7 x Siemens AG-SGT-A-65	(7) 66	462	2017	+ 3 CTs (472 MW) + 3 CCs (520 MW) at adjacent plant
Montana Power Station	4 x GE LMS100	(4) 131.8	527.2	2015-2016	
Alpine Power Plant	2 x GE 7 FA.05	226.9	453.8	2016	
Antelope Elk E.C.	3 x GE 7 FA.05	199.8	599.4	2015-2016	
Clayville	1 x RR Trent 60	73.5	73.5	2015	2023 c.f. 12.1%
Scattergood	2 x GE LMS 100 PA + 2 other	(2) 163.2 + (2) 106.9	876	4 units 2015	Plant includes two CCs and 4 CTs
Ector County	2 x GE7 FA.03	(2) 179.4	358.8	2015	
Perryman	1 x P&W FT 4000 + 1 other	141 /192	333	P&W 2015	
Charles D Lamb	1 x Siemens SGT6-2000E	122	122	2015	2023 c.f. 20.1%
Pioneer	3 x GE LM6000	(3) 60.5	181.5	2013-2014	+12 9.3 MW NG IC gen
Rio Grande	1 x GE LMS100PB	131.8	398	CT is 2013, 3 ST are older	+(3) NG steam turbines, 50,50,165MW
Cleveland County	4 x Siemens SGT6-5000F	(4) 184	736	2012	
Kearny Generating Station	10 x GE LM6000PC	(10) 60.5	605	(4) 2001, (6) 2012	
Almond Power Plant	3 x GE LM6000, 1 older	(3) 58, (1) 49.5	223.5	(3) 2012, (1) 1996	

Culbertson	1 x GE LMS100PA-SAC	108.2	108.2	2010	2023 c.f.. 44%
Redding Power Plant	no recent CTs, 42 MW CC	3 CC, 3 CT	183.5	1989-2011	2011 addition is a CC
Panoche EC	4 x GE LMS100PB-DL-E2	(4) 108	432	2009	
Brady Branch	(1) GE 7FA	185	783	2001	"+3 CC, 185,185,228
Bear Mountain Ltd.	(1) GE LM5000	46	46	1995	CHP with HRSG
Live Oak Ltd	(1) GE	46	46	1992	CHP with HRSG
Sand Hill EC	6 x GE LM6000	(6) 51.4	696.4	2001	+198, 190MW CC
Shelby County	8x GE LM6000	(8) 42	336	2000	
Almond Power Plant	3 x GE LM6000	(3) 58	174	1996	
Millcreek (UT)	2 x GE LM6000	(2) 40	80	2006, 2010	
Montpelier	4 x ?	(4) 59	236	2001	
Ladysmith	(5) GE 7FA	(5) 179.5	892.5	2001, 2008, 2009	
LV Sutton	2 x GE LM6000	(2) 60.5	851	2013 (CC), 2017(CT)	+ 288,221,221 MW CC