COMMENTS OF THE POWER GENERATORS AIR COALITION ON EPA'S PROPOSED RULE ENTITLED "REVIEW OF NEW SOURCE PERFORMANCE STANDARDS FOR STATIONARY COMBUSTION TURBINES AND STATIONARY GAS TURBINES"

89 Fed. Reg. 101,306 (Dec. 13, 2024)

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INTRODUCTION

The Power Generators Air Coalition ("PGen") appreciates the opportunity to submit these comments on the U.S. Environmental Protection Agency's ("EPA" or the "Agency") proposed rule entitled "Review of New Source Performance Standards for Stationary Combustion Turbines and Stationary Gas Turbines" ("Proposed Rule" or "Proposal").[1] The Proposed Rule, among other revisions to the New Source Performance Standards ("NSPS") for stationary combustion turbines ("CTs"), would adopt a new best system of emission reduction ("BSER") for oxides of nitrogen ("NOx") for various subcategories of CTs, lower the existing NOx standards of performance, and retain the sulfur dioxide ("SO_2") standard of performance for new, modified, and reconstructed CTs.

PGen is an incorporated nonprofit 501(c)(6) organization whose members are diverse electric generating companies—public power, rural electric cooperatives, and investor-owned utilities—with a mix of solar, wind, hydroelectric, nuclear, and fossil generation. PGen is a collaborative effort of electric generators to share information and expertise in the interest of constructively evaluating and effectively managing air emissions to meet and exceed environmental laws and regulations and in the interest of informing sound regulation and public

[1] 89 Fed. Reg. 101,306 (Dec. 13, 2024).

policy.[2] Our members include leaders in the ongoing transition to cleaner energy in the United States. PGen and its members work to ensure that environmental regulations support a clean, safe, reliable, and affordable electric system for the nation.

PGen members own and operate CTs that are regulated under the Proposed Rule. Indeed, PGen members expect that CTs—in particular natural gas-fired turbines—will continue to form the backbone of the nation's electric generating fleet for the foreseeable future by providing electric power generation to meet an accelerating demand for electricity—especially due to artificial intelligence systems—and critical, dispatchable generation support for intermittent renewable energy. Accordingly, PGen has a substantial interest in the Proposed Rule.

SUMMARY OF COMMENTS

<u>Section I – EPA Should Refine the Proposed NSPS to Better Reflect Realities of the Energy Industry.</u>

- EPA should revise the size-based subcategories in the Proposed Rule to capture and accommodate variations within certain classes of CTs that will bear significantly on the cost of compliance. Specifically, the "large" CT subcategory should be further divided to account for large variation in NOx reduction BSER and cost effectiveness for three classes of frame turbines used in the power industry as follows:
    - E-Class frame turbines (capacities in the 90 to 150 megawatt ("MW") range) in simple cycle mode: performance standard of 5 parts per million ("ppm"), reflecting advanced combustion controls as BSER for intermediate and base load. The performance standard should be 15 ppm for the low load subcategory.
    - F-Class frame turbines (capacities in the 200 to 320 MW range) in simple cycle mode: performance standard of 9 ppm, reflecting advanced combustion controls as BSER for intermediate and base load. The performance standard should be 15 ppm for the low load subcategory.
    - H-Class frame turbines (the largest CTs on the market, with capacities generally above 320 MW) in simple cycle mode: performance standard of 25 ppm, reflecting advanced combustion controls as BSER for all load subcategories.
    - All CTs in combined cycle mode (i.e., base load subcategory): performance standard based on selective catalytic reduction ("SCR") controls as BSER.

[2] Additional information on PGen and its members can be found at https://www.pgen.org.

Section II – Even Where SCR May Be Considered BSER, the Proposed NOx Standard of 3 ppm Is Not Appropriate.

- EPA should revise the duty-based subcategories in the Proposed Rule to better reflect the changing capacity factors for certain CTs used in simple cycle mode and the typical capacity factors of combined cycle CTs. Specifically, an annual capacity factor of 60% is a more appropriate demarcation between CTs that operate as simple cycle CTs and CTs that operate invariably as combined cycle CTs.
- PGen agrees that the data do not support a 2 ppm standard where the BSER is SCR.
- The proposed 3 ppm standard where the BSER is SCR is not consistently achievable.

Section III – The Standard of Performance for Large Modified Units Should Be Based on Combustion Controls BSER.

- SCRs are difficult and very costly, if not impossible, to retrofit at existing CT facilities. For this reason, combustion controls should be BSER for modified CTs.
- The SCR at a combined cycle affected facility must be installed between the first and second bundle of tubes of the heat recovery steam generator ("HRSG"). There is no space to do so at an existing facility not already equipped with SCR.
- The SCR at an existing simple cycle affected facility is large and must be installed close to the CT, where the stack and other equipment is located. The cost for such retrofits is prohibitive.

Section IV – EPA's Apparent Concern About a "Perverse Incentive" of the Part-Load Rate Is Misplaced, and Its Proposed Solutions Are Unlawful and Unsound.

- Partially engaging advanced combustion controls and SCR during part-load operations is not feasible or effective.
- EPA's apparent concern of a "perverse incentive" to operate CTs at part-load to avoid more stringent NOx limits at high load ignores the realities of CT design and operation. In addition, there is a strong economic disincentive to such atypical operations. CTs are designed to start up in a relatively short period of time and to ramp up to high load operations as fast as possible, within the limitations of the equipment. Other than during these periods, CTs very rarely operate at part load, and if they do, it is to meet dispatch prerogatives.
- EPA does not have the authority under Section 111 of the Clean Air Act ("CAA") to adopt a standard of performance that is designed or has the effect of dictating the methods and modes of operation of CTs.
- EPA's proposed "12-Calendar-Month NOx Standards" are, furthermore, unworkable, arbitrary, and capricious.

Section V – EPA's Proposal to Base "Reconstruction" on the "Simple-Cycle Portion" of a Combined-Cycle Facility Is Unlawful and Arbitrary and Capricious.

- The reconstruction rule under the general provisions of Part 60 is unlawful and was constructively reopened for review in the Proposal. It should be repealed.
- Even if the general reconstruction provision is not subject to review, or even if it is lawful, EPA has no authority to promulgate the proposed reconstruction provision in the Proposal.
- The proposed reconstruction provision in the Proposal is unworkable, arbitrary and capricious because it requires substantial controls at the HRSG, which would not be otherwise modified in a reconstruction of the simple cycle portion of the affected facility.

Section VI – EPA's Proposal to Base Whether an Affected Facility Is "New" on the "Simple-Cycle Portion" of a Combined-Cycle Facility Is Also Unlawful and Arbitrary and Capricious.

- The proposed "new" construction provision in the Proposal is unworkable, arbitrary and capricious because it requires substantial controls at the HRSG, which would not be otherwise modified in a reconstruction of the simple cycle portion of the affected facility.

Section VII – Monitoring and Reporting Issues

- EPA should address myriad monitoring, reporting, and recordkeeping issues.

COMMENTS

I. EPA Should Refine the Subcategories in the Proposed Rule to Better Reflect the Common Characteristics of Classes of CTs, and EPA Should Tailor the BSER and Standards to Fit These Subcategories.

In the Proposed Rule, EPA proposes to create subcategories that reflect combinations of duty and turbine size. As presently proposed, EPA subcategorizes CTs using duty based on annual (12-month rolling) capacity factor: CTs with a capacity factor of less than 20% are low load units; CTs with a capacity factor of 20% to 40% are intermediate load units; and CTs with a capacity factor of more than 40% are base load units. EPA also subcategorizes CTs using size based on hourly heat input capacity. CTs with a combustion capacity of less than 250 million British thermal units per hour ("MMBtu/h") are small units; CTs with a combustion capacity of 250 MMBtu/h to 850 MMBtu/h are medium units; and CTs with a combustion capacity of more than 850 MMBtu/h are large units. EPA should revise its subcategories to better reflect the common characteristics of similar types and classes of CTs.

A. The demarcation for base load CTs should be an annual capacity factor of 60%.

The duty-based subcategories are generally sensible, except for the denomination of units that operate at an annual capacity factor of more than 40% as "base load." Base load is a technical term in the electric power industry, and it refers to units that operate a majority of the time and that contribute to the part of load demand that is present most times; other types of unit duties are "load following" and "peaking." Often, peaking units operate at low annual capacity factors, but they are critical to meeting the highest load demand that the grid experiences, such as on the hottest or coldest days of the year. Denominating a unit that operates at an annual capacity factor of 40% as base load is akin to calling an employee who works 16 hours per week a "full-time" employee; the threshold that EPA selected is too low. The threshold for the base load category should be 60%. Most combined cycle CTs, which do operate at base load in the industry sense, operate at an annual capacity factor of 60%. In contrast, most simple CTs operate at low annual factors (often less than 20% for medium-size peaking units), with large frame CTs recently approaching 40%. Some PGen members expect, if not predict, that some frame CTs will likely operate at an annual capacity of more than 40% in the near future as demand for power continues to climb, largely due to the artificial intelligence boom.

For these reasons, PGen urges EPA to revise the demarcation between intermediate and base load CTs to an annual capacity factor of 60%. This would be more consistent with the common industry usage of the term base load, and it would help differentiate, within the subcategory construct that the statute envisions and that EPA embraces in the NSPS program, between units that typically operate in simple cycle mode and those that operate in combined cycle mode. The differences between these two modes are critical and highly relevant for this rule. Most notably, for combined cycle CTs, SCR is essentially incorporated in the HRSG and is less costly than SCRs used for CTs operating in simple-cycle mode. This cost difference occurs because CTs operating in simple-cycle mode produce very high exhaust gas temperatures that necessitate more costly equipment to withstand the higher temperatures.

As to the subcategorization of simple cycle CTs, the Proposed Rule's 20% demarcation between low-load units and intermediate load units may make sense, if EPA is attempting to avoid a large range that results, for example, in a standard that is cost-effective at the upper end of the range but not cost-effective at the lower end of the range.

B. The large CT subcategory should be further divided into three categories that encompass E-Class, F-Class, and H-Class frame CTs.

EPA has divided turbines into three size-based categories. Small turbines, with a heat input of 250 MMBtu/h or less, are rarely used in the electric generating industry and are not addressed here. Most turbines used in the electric generating industry are either medium-size (250 to 850 MMBtu/hr, roughly equivalent to 25 to 85 MW capacity) or large (above 850 MMBtu/h). The medium category makes sense, as this category comprises mostly aeroderivative turbines with generally similar characteristics. Although the large category can be viewed as reasonably encompassing most frame-type combustion turbines, this category spans three different classes of turbines with very different characteristics. For this reason, the "large" category should be further divided into smaller categories to avoid very different cost-effectiveness results across the category.

Specifically, as the comments of the Electric Power Research Institute[3] and as the report included herein as Attachment A[4] explain, there are three major but distinct classes of frame turbines with vastly different characteristics and performance capacities:

- E-Class frame turbines have capacities in the 90 to 150 MW range. With Dry Low-NOx ("DLN") technology, they emit NOx at 15 ppm. With advanced DLN technology, they are able to achieve NOx emission levels as low as 5 ppm.
- F-Class frame turbines have capacities in the 200 to 320 MW range. With DLN technology, these units also emit NOx at 15 ppm. With advanced DLN technology, they are only able to achieve NOx emission levels as low as 9 ppm.
- H-Class frame turbines (and similar large CTs, e.g., J Frame Turbines) are the largest CTs on the market, with capacities generally above 320 MW. These turbines, even with DLN technology, are invariably unable to achieve lower than a 25 ppm NOx rate. There is no advanced DLN technology for these very large turbines, which operate at substantially higher temperatures than F-Class and E-Class frame turbines.

The marked difference between these classes of "large" turbines can and should be addressed using the tool that Congress explicitly provided in the statute: subcategorization. 42 U.S.C. § 7411(b)(2). Otherwise, putting all three classes of large turbines into a single category necessarily results in either an arbitrary and unjustifiable standard (as is the case in the Proposal) for some classes of turbines or, if adjusted for those classes, a standard that falls short of the best performing CTs for other classes of turbines.

[3] Comments of the Electric Power Research Institute on Environmental Protection Agency Review of New Source Performance Standards (NSPS) for Stationary Combustion Turbines and Stationary Gas Turbines—Proposed Rule (Mar. 13, 2025), available at https://www.regulations.gov/comment/EPA-HQ-OAR-2024-0419-0059.

[4] J. E. Cichanowicz & M. Hein, *Technical Basis for Comments: New Source Performance Standards for Stationary Combustion Turbines and Gas Turbines* (Apr. 14, 2025) ("C&H Report").

1. The large CT subcategory should be further divided into three categories that encompass E-Class, F-Class, and H-Class frame CTs for intermediate load.

As shown in Table 7-3 of the C&H Report (reproduced below) below, a 3-ppm limit (based on SCR as BSER) for large turbines operating in simple-cycle mode in the intermediate load range is not cost-effective, even assuming EPA's outdated cost numbers reflect the modern investment requirement. The cost-per-ton is substantially higher, and the technology therefore less cost effective, when more recent cost numbers are used. *See* C&H Report at 33-34.

Table 7-3 of C&H Report: Summary of Revised Cost Evaluation

Column A Fed Reg: 101334	Turbine Class	Column B NOx Δ ppm	Column C GT Design	Column D SCR $/kW	Column E Capacity Factor	Column F $/ton EPA-HQ-OAR-2024-0419-0017 _attachment_1	Column G $/ton (@ 2,000 MBtu/h)
Low (<20%)	H	25 to 3	SC	28	5	18,391	25,011
Intermediate (20-40%)			SC	28	20	4,894	7,899
Base >40%)			CC	12	40	3,545	5,047
Low (<20%)	F	15 to 3	SC	28	5	33,000	45,256
Intermediate (20-40%)			SC	28	20	8,400	13,884
Base >40%)			CC	12	40	3,800	5,732
Low (<20%)	F	9 to 3	SC	28	5	65,000	89,361
Intermediate (20-40%)			SC	28	20	16,000	26,618
Base >40%)			CC	12	40	6,400	10,314
Low (<20%)	E	5 to 3	SC	28	5	190,000	261,761
Intermediate (20-40%)			SC	28	20	42,000	75,553
Base >40%			CC	12	40	16,000	27,272

The cost-effectiveness evaluation results using both EPA's assumptions and modern estimates are as follows:

- E-Class: Reduction from 5 ppm to 3 ppm NOx, at a capacity factor of 20% (the low end of the intermediate load category): $75,553 per ton of NOx, based on EPA's own outdated SCR cost. Using a more recent SCR cost, the cost-effectiveness is $551,000 per ton of NOx. For E-Class turbines operating in simple-cycle mode at intermediate load, therefore, SCR is not cost-effective, and the standard for these units should instead be based on advanced DLN at 5 ppm.

- F-Class: Reduction from 9 ppm to 3 ppm NOx, at a capacity factor of 20%: $26,618 per ton of NOx based on EPA's own outdated SCR cost. Using a more recent SCR cost, the cost-effectiveness is $48,365 per ton of NOx. For F-Class turbines operating in simple-cycle mode at intermediate load, therefore, SCR is not cost-effective, and the standard for these units should instead be based on advanced DLN at 9 ppm.
- H-Class: Reduction from 25 ppm to 3 ppm NOx, at a capacity factor of 20%: $9,500 per ton of NOx based on EPA's own outdated SCR cost. Using a more recent SCR cost, the cost-effectiveness was up to $19,275 per ton of NOx for one installation. For H-Class turbines operating in simple-cycle mode at intermediate load, therefore, SCR is not cost-effective, and the standard for these units should instead be based on DLN at 25 ppm.

The above data demonstrate that EPA's proposed standard of 3 ppm for all large combustion turbines at intermediate load is arbitrary and unreasonably costly, even under EPA's own cost assumptions. Putting the cost assumptions aside, EPA based its entire analysis for cost-effectiveness of an SCR as BSER for large CTs at intermediate load on one of the largest units on the market (4,450 MMBtu/h, which is roughly equivalent to a 500 MW H-Class CT) operating at a capacity factor of 30% (which is the mid-point of the range for the intermediate load subcategory in the Proposal), and reducing NOx from 25 ppm to 3 ppm. This scenario represents only a small subset of the class EPA claims to approximate, and EPA's reliance on this scenario to model the intermediate-load category as a whole is arbitrary and capricious. First, the intermediate load range is 20% to 40%. The highest-cost situation is 20%, not 30% as used in the Proposed Rule, because there are more NOx emissions to reduce at higher capacity factors. By basing its proposed standard on a capacity factor of 30%, EPA is subjecting any unit that would run between 20-30% to a higher cost per ton of NOx. If the capacity factor range is 20 to 40%, the analysis must be based on the worst-case scenario, which is a capacity factor of 20%, so that units operating at that level can be cost-effectively controlled. Second, very large CTs are a very small fraction of the population of simple-cycle turbines with heat input capacity larger than 850 MMBtu/h, and it is well understood that the relative cost of SCR decreases as the turbine size increases due to economies of scale. EPA has thus arbitrarily based its analysis on a case that inappropriately minimizes cost for the vast majority of frame CTs operating in simple-cycle mode—namely, E-Class and F-Class turbines.

Moreover, even if SCR were cost-effective for a very large H-Class turbine operating at a capacity factor of 30%, EPA's selection of a 3-ppm SCR as BSER for *all* frame turbines is arbitrary and capricious. The CT size and capacity factor EPA assumed in its analysis are not generalizable to the category as a whole and do not reflect reality for many H-Class turbines. Moreover, EPA's chosen CT size and capacity factor assumptions are even less appropriate for and applicable to F-Class and E-Class frame turbines. These smaller-frame CTs are likely to operate less than H-Class CTs, thus resulting in less cost-effective NOx reductions. More importantly, as shown in the Table above, these CTs are not only much smaller than H-Class turbines, resulting in more costly SCRs (on a dollar per kilowatt, relative basis), but can also achieve much lower emissions rates—as low as 9 ppm for F-Class CTs and 5 ppm for E-Class CTs using advanced combustion controls. This results in dramatically different cost-effectiveness values for SCRs applied to F-Class and E-Class frame turbines relative to H-Class turbines.

If EPA will not subcategorize the different classes of large frame turbines, it should ensure that the cost-effectiveness analysis represents all turbines within the subcategory. Therefore, to demonstrate that SCR is cost-effective for the entire subcategory, as EPA claims, EPA should base its analysis on the least cost-effective case covered by the subcategory—i.e., an E-Class turbine operating at 20% capacity factor. EPA cannot possibly show that an SCR would be cost-effective for this limiting case: the cost-effectiveness of such an SCR, based on EPA's own outdated SCR cost numbers, is $75,553—well above any reasonable amount EPA has ever suggested as cost-effective under NSPS. Since SCR is not BSER for the large CT subcategory as the Proposal defines it, EPA must select combustion controls (DLN) as the BSER. The NOx standard would need to be the highest DLN-based rate, 25 ppm, which is the appropriate standard for H-Class CTs. Any lower standard for the entire frame CT category would not be cost-effective for H-Class turbines. Even if SCR were to be found cost-effective for H-Class turbines operating in the intermediate load subcategory, the standard for the entire large CT subcategory as defined in the Proposal cannot be lower than 9 ppm. Such a standard is compelled to ensure the selected standard is cost-effective both for F-Class CTs and E-Class CTs.

2. The large CT subcategory should be further divided into three categories that encompass E-Class, F-Class, and H-Class frame CTs for low load.

SCR is even more cost-ineffective for large turbines operating at low load. That is necessarily so because the capital charge for the SCR remains the same, but the utilization is much lower (reasonably assumed by EPA to be an annual capacity factor of 5%). For such low load operations, the standard should be 15 ppm for E-Class and F-Class turbines, and 25 ppm for H-Class turbines. A 15-ppm standard is appropriate for E-Class and F-Class turbines because that is the rate most often achieved with DLN. The DLN-based rate of H-Class turbines is invariably 25 ppm. Reducing the rate for an H-Class turbine operating in the low load subcategory (capacity factor of 5% for the analysis) from 25 ppm to 15 ppm would require an SCR, but it would be even less cost-effective than an SCR for H-Class units operating in the intermediate load subcategory because the cost of the SCR is the same for less NOx reduction payoff.

II. Even Where SCR May Be Considered BSER, the Proposed NOx Standard Is Not Appropriate.

PGen agrees that SCR is BSER for medium CTs (most aeroderivative CTs) in the intermediate load range, as well as large, *combined cycle* CTs running at base load. If EPA intends to use the duty-based subcategorization as a proxy for combined cycle operations, however, it should increase the demarcation between base load and intermediate load to 60%, as discussed previously. This would avoid requiring SCR for frame turbines operating in simple cycle mode. PGen also agrees with EPA's conclusion that 2 ppm is not the appropriate standard for units with SCR. 89 Fed. Reg. at 101,336. As the C&H Report shows, among the "reference" units that EPA used for its analysis, the vast majority cannot consistently maintain a 2 ppm NOx rate. *See* C&H Report at 19.[5]

Furthermore, while there is a higher frequency among the reference units of meeting a NOx rate of 3 ppm, very few of those units are able to meet that standard 100% of the time. *Id.* at 20-21. Indeed, half of the reference units are unable to achieve a 3 ppm NOx emission rate on a continuous basis, "suggest[ing] the compliance margin is small." *Id.* at 21. A large majority of the reference units operating in simple-cycle mode are unable to meet a standard of 3 ppm consistently. *See id.* This is consistent with the experience of PGen members. For these reasons, a 3-ppm standard for all subcategories for which SCR is determined to be BSER is not supported by the data.

III. The Standard for Large Modified Units Should Be Based on Combustion Controls BSER.

EPA proposes to subject modified large turbines operating at intermediate and base load to the same BSER (SCR) and NOx standard as these types of units when they are new or reconstructed. This BSER determination is arbitrary and capricious because EPA provides no analysis anywhere in the record evaluating whether, much less explaining why it believes, SCR is adequately demonstrated, achievable, or cost-effective as a retrofit for existing turbines.

[5] Notably, although the C&H Report's results are generally consistent with EPA's analyses, they are not identical. The C&H Report's authors have been unable to determine the reason for the discrepancy, and EPA has not included in the docket the calculation details necessary to determine the source of the difference.

As far as we can tell, EPA's determination appears to be based on the bald assumption that existing, large combustion turbines that undertake a modification are no different than new CTs and can install SCR cost-effectively. This assumption is wrong. For CTs operating in combined-cycle mode, the SCR is installed in the HRSG, after the first bundle of tubes, where the exhaust has become more uniform and lower in temperature. If the HRSG does not already have an SCR, there is simply no space to install one between the first and second tube bundles without cutting the HRSG in half and elongating it to make room for the SCR, which would be cost prohibitive. EPA has not only failed to point to any such previous retrofit (suggesting it is not adequately demonstrated) but has also failed to evaluate even the theoretical feasibility and cost of such a retrofit.

Large turbines operating in simple-cycle mode have a similar type of problem. As the C&H Report explains, retrofitting an existing simple-cycle combustion turbine with SCR "will require either relocating the stack, or configuring the SCR reactor as a parallel duct or 'sidecar' concept."[6] In addition to creating technical issues for the SCR to function properly,[7] such retrofits are extremely costly.[8] They also result in a derating of the existing CT, with corresponding negative impacts on grid reliability.

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[6] C&H Report at 35.

[7] *Id.* ("Either of these [retrofit actions] adds gas pressure drop and create a tortuous path for gas flow, making it difficult to achieve a uniform gas flow distribution at the catalyst inlet.").

[8] *See id.* (reporting one Midwestern owner of a 450-500 MW CT was quoted an estimated cost of $35-55 million for a turnkey installation on a single unit, translating to a levelized cost of over $20,000 per ton based on a capacity factor of 20%, H-Class design, and a 25 ppm combustor NOx); *see also id.* at 36 (discussing an engineering study evaluating the design and cost to retrofit SCR to a GE-7 FA Frame unit as $46,366 per ton for a 100% capacity factor, which implies approximately $200,000 per ton for 20% capacity factor).

For the reasons above, it is arbitrary and capricious to subject modified large combustion turbines in the base load and intermediate load subcategories to the same standard as new and reconstructed units. First, EPA cannot do so without any analysis or justification, save a bare, utterly unsupported, and highly implausible assumption that there is no difference between retrofitting an existing unit and constructing a brand-new unit. Second, as the C&H Report explains, there are major differences between the two situations; such retrofits are not cost-effective, and perhaps not even feasible, in some situations. EPA should instead adopt the following standards for modified large combustion turbines:

- H-Class turbines: 25 ppm
- F-Class and E-Class turbines: 15 ppm

IV. EPA's Concern About a "Perverse Incentive" of the Part-Load Rate Is Misplaced, and Its Proposed Solutions Are Unlawful and Unsound.

EPA recognizes, as it must, that control strategies for NOx are simply ineffective at part load—indeed, in the vast majority of situations, the controls cannot be engaged. For this reason, there is necessarily a large difference in the achievable NOx emission rate at part load and high load. EPA's suggestions in the Proposal about partly engaging NOx controls at part load (to obtain an unspecified lower NOx rate) are not achievable, much less adequately demonstrated. *See* C&H Report at 17-18 (explaining the technical challenges that prevent using SCR at part load). There is certainly nothing in the record to support them. Additionally, EPA's attempt to design an alternative standard to dictate *how* a unit is allowed to operate is ill-conceived and unlawful.

A. The purported "perverse incentive" for CTs to increase operations at part load just to avoid the more stringent standards at high load is fiction.

The Proposal repeatedly invokes the existence of a "perverse incentive" to run CTs at part load more often than normal operations simply to avoid the more stringent standards at high load as justification for a series of ill-conceived (see Section IV.C, below) alternative or additional forms of the standard. The perverse incentive that EPA imagines is pure fiction. Quite simply, there is no such incentive because, regardless of the difference between the part load and high load emission standards, the standards would not drive operations down to a part load level; turbines are not designed to run continuously at part load, and the resulting inefficiency and revenue losses would present a much more compelling economic concern.

First, the overwhelming majority of, if not all, CT operations follow a similar pattern: once the turbine is started, it is ramped up to high load as fast as possible within the limitations of the equipment, and it operates at this load the vast majority of the time because that is how CTs are designed to operate. Most importantly, the heat rate at part load is significantly higher than at high load, meaning a unit of fuel combusted at part load produces less electricity than that same unit of fuel would produce if combusted at high load. This makes it economically irrational to extend operation at part load (unless, for some reason, it is required for some period due to grid reliability and stability constraints).

Second, limiting a CT to part load operations to avoid engaging the DLN combustion controls makes no sense economically. Any cost of engaging DLN is infinitesimally small compared to the loss of revenue from limiting operations to part load. Indeed, limiting operations even to avoid operating an expensive piece of control equipment (like SCR, where SCR is found to be BSER) would also be economically irrational. As the C&H Report shows, a unit that operates at no more than 70% of load for 1,600-1,800 hours per year, even after accounting for the "cost penalty for SCR capital repayment and operation" for operations above 70% of load, would forgo more than 20% of the revenue associated with high-load operations (about $0.8-$1 million of a total revenue of about $3.7-$4.9 million). C&H Report at 14-15.

In short, EPA's concern about a perverse incentive due to a difference between part-load and high-load standards has no basis in fact. The reality is that units in the electric generating industry operate primarily, if not invariably, as called upon to meet demand and it would be technically detrimental and economically irrational for units to operate at part load just to avoid the more stringent high-load standards.

B. EPA should not, and it has no authority to, adopt a standard that dictates CTs' modes and levels of operation.

In the Proposal, EPA solicits comments on limiting the amount of part load operations for CTs, and even proposes different forms of the standard designed to restrict part load operations, including startup and shutdown sequences. But EPA fails to consider the underlying practical needs addressed by part load operations. First, part load operations encompass the startup and shut-down sequence of the units, and a unit necessarily must operate at part load during start up and as it ramps up to high load (70% of rated capacity). Second, as explained above, CTs are designed to operate most efficiently and effectively at high load. Therefore, the only possible reason, at least in the power industry, for a unit to operate at part load outside the startup, ramp-up, and shutdown periods—notwithstanding the design—is to balance a demand for power in the moment with a stable grid. Therefore, EPA should not set an NSPS standard that dictates *how and at what level* a unit must operate. Rather, the electric market and the utilities' obligation to maintain grid reliability set generating-asset utilization and output demands, not EPA.

Not only would it be bad policy for EPA to dictate how much energy electric generating assets may produce, but EPA has no authority to do so. Although, a standard that explicitly restricts, or has the effect to restrict, the number of startup and shutdown and part load operations is not "generation shifting" of exactly the same type that the Supreme Court has told EPA it may not use to justify a NSPS, *see West Virginia v. EPA*, 597 U.S. 697, 735 (2021), the principle is the same: Congress did not authorize EPA in Section 111 of the CAA to dictate energy operations. The market, the regional transmission organizations, and balancing authorities dictate, or have the authority to dictate, such operations. Under Section 111, EPA must take the units as the market presents them and as the industry proposes them, evaluate the BSER (including for various modes of operations, as appropriate), and set standards that reflect the BSER. EPA cannot simply say: you must run your units in this manner to minimize emissions. If that were the case, EPA would have the authority to (perhaps almost always) determine that shutting down whatever industrial source is being evaluated is BSER. That is not, and cannot be, the case.

EPA has no authority under Section 111 of the CAA to restrict part load operations of CTs, including the number of startup and shutdown sequences, whether explicitly or by designing the standard to preclude it, such as by eliminating the part-load standard, even while allowing a longer term average for the limit, or by promulgating mass-based standards that do not account for part-load rates.

C. EPA's proposed "12-Calendar-Month NOx Standards" Are Unworkable, Arbitrary, and Capricious.

Even assuming for the sake of argument that EPA had authority to adopt a standard that aims to regulate both the level of controls (i.e., the BSER) and the operations of a source category, EPA's proposed "12-Calendar-Month NOx Standards" are unworkable, arbitrary, and capricious. The C&H Report calculated the capacity factor limitations that EPA's proposed 12-Calendar-Month NOx Standard of 0.21, 0.45, and even 0.75 tons NOx per MW would impose on a CT for three different scenarios: (1) with an average high-load NOx emission rate ranging from 3 ppm to 25 ppm; (2) for various emission rates for part-load operations; and (3) for operations at high load ranging from 60% to 95% of the time. The results, reproduced below, are stunning.

C& H Report Table 3-1. Maximum Capacity Factor: 0.21, 0.45, and 0.75 Mass Limit, 96 ppm Part Load NOx Rate

Part-Load PPM	Mass-based Limit 0.21 Tons/MW/Year					Mass-based Limit 0.45 Tons/MW/Year					Mass-based Limit 0.75 Tons/MW/Year			
96	High Load Rate (ppm)					High Load Rate (ppm)					High Load Rate (ppm)			
High Load %	3	5	9	15	25	3	5	9	15	25	3	5	9	15
95	26%	21%	15%	11%	7%	56%	45%	32%	23%	15%	93%	75%	54%	38%
90	16%	14%	11%	9%	6%	35%	30%	24%	19%	13%	58%	51%	40%	31%
80	9%	9%	8%	6%	5%	20%	18%	16%	14%	11%	33%	31%	27%	23%
70	6%	6%	6%	5%	4%	14%	13%	12%	11%	9%	23%	22%	20%	18%
60	5%	5%	5%	4%	4%	11%	10%	10%	9%	8%	18%	17%	16%	15%
50	4%	4%	4%	4%	3%	9%	8%	8%	8%	7%	14%	14%	14%	13%

C&H Report Table 3-2. Maximum Capacity Factor: 0.21, 0.45, and 0.75 Mass Limit, 75 ppm Part Load NOx Rate

Part-Load PPM	Mass-based Limit 0.21 Tons/MW/Year					Mass-based Limit 0.45 Tons/MW/Year					Mass-based Limit 0.75 Tons/MW/Year			
75	High Load Rate (ppm)					High Load Rate (ppm)					High Load Rate (ppm)			
High Load %	3	5	9	15	25	3	5	9	15	25	3	5	9	15
95	30%	24%	16%	11%	7%	65%	50%	35%	24%	16%	100%	84%	58%	40%
90	20%	17%	13%	10%	7%	42%	36%	28%	20%	14%	70%	60%	46%	34%
80	12%	11%	9%	7%	6%	25%	23%	19%	16%	12%	41%	38%	32%	26%
70	8%	8%	7%	6%	5%	17%	17%	15%	13%	11%	29%	28%	25%	22%
60	6%	6%	6%	5%	4%	13%	13%	12%	11%	10%	22%	22%	20%	18%
50	5%	5%	5%	4%	4%	11%	11%	10%	10%	9%	18%	18%	17%	16%

C&H Table 3-3. Maximum Capacity Factor: 0.21, 0.45, and 0.75 Mass Limit, 50 ppm Part Load NOx Rate

Part-Load PPM	Mass-based Limit 0.21 Tons/MW/Year					Mass-based Limit 0.45 Tons/MW/Year					Mass-based Limit 0.75 Tons/MW/Year			
50	High Load Rate (ppm)					High Load Rate (ppm)					High Load Rate (ppm)			
High Load %	3	5	9	15	25	3	5	9	15	25	3	5	9	15
95	37%	28%	18%	12%	8%	80%	59%	39%	26%	16%	100%	99%	65%	43%
90	26%	21%	15%	11%	7%	56%	45%	33%	23%	16%	93%	75%	55%	39%
80	16%	14%	12%	9%	7%	35%	31%	25%	20%	14%	58%	51%	42%	33%
70	12%	11%	9%	8%	6%	25%	23%	20%	17%	13%	42%	39%	34%	28%
60	9%	9%	8%	7%	6%	20%	19%	17%	15%	12%	33%	31%	28%	25%
50	8%	7%	7%	6%	5%	16%	16%	15%	13%	11%	27%	26%	24%	22%

Based on the results above, to achieve a 12-Calendar-Month NOx Standard of 0.21 tons NOx per MW, a unit that has a high-load NO_X emission rate of 3 ppm, a part-load average emission rate of 96 ppm, and that operates almost all the time at high load (i.e., 95% of the time) could operate at no more than an annual capacity factor of 18%—less than the low-load subcategory. Even at an unrealistically low average part-load emission rate of 50 ppm, that same unit would still be limited to a maximum capacity factor of 26%. The picture is progressively worse as the percentage of high load operations decreases below 95%, as is typically the case for simple-cycle turbines (because they are typically peaking units, with a large number of startup/shutdown cycles). For example, if that same unit were to operate 60% of the time at high load, it could operate at no more than an annual capacity factor of 3%. And at an unrealistically low average part-load emission rate of 50 ppm, it would still be limited to a maximum capacity factor of 6%. Such severe capacity factor limitations are nonsensical.

Increasing the 12-Calendar-Month NOx Standard to 0.45 or even 0.75 tons NOx per MW does not ameliorate the situation. To achieve 0.45 tons NOx per MW, a unit with a high-load NO_x emission rate of 3 ppm and a part-load average emission rate of 96 ppm could operate at no more than an annual capacity factor of 7% to 39% (for high-load operations percentages of 60% to 95%). And to achieve 0.75 tons NOx per MW, that same unit could operate at a maximum annual capacity factor of about 11% to 64%. Even if the unit were to decrease its part-load emission rate to an unrealistic 50 ppm, its maximum capacity factor would be 14% to 56%.

As the discussion above demonstrates, EPA's proposed "12-Calendar-Month NOx Standards" are ill-conceived and unworkable. They are arbitrary and capricious for this reason, as well as unlawful for the reasons discussed previously.

V. EPA's Proposal to Base "Reconstruction" on the "Simple-Cycle Portion" of a Combined-Cycle Facility Is Unlawful, Arbitrary, and Capricious.

CAA Section 111 standards apply to "new sources." *See* 42 U.S.C. § 7411(b)(1)(B). The Act defines a "new source" as "any stationary source, the ***construction*** or ***modification*** of which is commenced after" a standard is proposed or finalized. *Id.* § 7411(a)(2) (emphases added). "Modification" is defined as "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted" by the source. *Id.* § 7411(a)(4). The first NSPS regulations reflected the statutory command, applying standards only to newly constructed or modified affected facilities.

As part of its 1975 NSPS regulations, however, EPA adopted a regulation that created out of whole cloth a new subcategory of units to which a standard would apply: "reconstructed" units. The so-called reconstruction rule, adopted in 1975 and (still) located in the general provisions of 40 C.F.R. Part 60, provides that "[a]n existing facility, upon reconstruction, becomes an affected facility, *irrespective of any change in emission rate*." 40 C.F.R. § 60.15(a) (emphasis added). According to the 1975 rule, reconstruction is triggered when an owner or operator replaces the components of an existing facility to such an extent that the "fixed capital cost[9] of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility." 40 C.F.R. § 60.15(b)(1). Although a reconstructed unit might not be required to meet the applicable standards under Part 60 if EPA deems it "technologically and economically" infeasible to do so, 40 C.F.R. § 60.15(b)(2), such determinations can take a long time to make and are vulnerable to third party challenges.

For almost fifty years, EPA has defined reconstruction as described above, most notably to base it on the replacement of 50% of the affected facility. As EPA explained in 1975, the equipment to be considered as "fixed capital cost" includes major process equipment, instrumentation, auxiliary facilities, buildings, and structures. 40 Fed. Reg. 58,416, 58,418 (Dec. 16, 1975). EPA's rationale for the reconstruction rule was "that replacement of many of the components of a facility can be substantially equivalent to totally replacing it at the end of its useful life with a newly constructed affected facility." *Id.* at 58,417. This Proposal, however, proposes a radical revision to the definition of "reconstruction" as applied to CTs that are part of a combined-cycle affected facility. The Agency proposes to base the reconstruction test for

[9] "'Fixed capital cost' means the capital needed to provide all the depreciable components." 40 C.F.R. § 60.15(c).

Subpart KKKKa on "only the simple cycle portion of a combined cycle." Proposed 40 C.F.R. § 60.4305a.[10]

EPA should not adopt this definition of reconstruction for four reasons: (1) the reconstruction rule (in 40 C.F.R. § 60.15) is inconsistent with the CAA and should be repealed; (2) even if EPA does not repeal the general reconstruction rule, applying the new KKKKa standards to a reconstructed CT is unlawful; (3) subjecting an entire combined-cycle affected facility to a standard based on replacement of less than 50% of the facility is not equivalent to a new affected facility under the plain meaning of "new"; and (4) subjecting an entire combined-cycle affected facility to the standard based on work involving only the simple-cycle portion of the facility is arbitrary and capricious.

A. The NSPS reconstruction rule should be repealed because it is inconsistent with the statute.

1. The NSPS reconstruction rule is unlawful.

The CAA does not grant EPA the power to apply new source performance standards to reconstructed stationary sources. "It is axiomatic that an administrative agency's power to

[10] *See* 89 Fed. Reg. at 101,314 ("The reconstruction applicability determination would be based on whether the fixed capital costs of the replacement of components of the combustion turbine engine portion exceed 50 percent of the fixed capital costs that would be required to install *only* a comparable new combustion turbine engine portion of the affected facility.") (emphasis in original). We note that the preamble language is inconsistent with the proposed regulatory language. The proposed regulatory language would base the reconstruction determination on the "simple cycle portion" of a combined cycle. The simple cycle portion, however, to the extent it is considered a separate affected facility, would encompass "all equipment including, but not limited to, the combustion turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except post combustion emissions control equipment), … fuel compressor, heater, and/or pump, post-combustion emission control technology, any ancillary components and sub-components comprising any simple cycle stationary combustion turbine." *See* Proposed 40 C.F.R. § 60.4420a (defining "stationary combustion turbine"). In the preamble, EPA purports that reconstruction would be based on replacing 50% of the "combustion turbine engine"; but the combustion turbine engine is only a subset of the simple-cycle portion of a combined cycle.

promulgate legislative regulations is limited to the authority delegated by Congress." *Bowen v. Georgetown Univ. Hosp.*, 488 U.S. 204, 208 (1988). The Act plainly authorizes EPA to establish standards of performance only for newly constructed or modified sources, but nothing in the Act grants EPA the authority to establish NSPS for reconstructed sources. Section 111 merely directs the Agency to set such standards for "any stationary source, the *construction or modification* of which is commenced" after the publication of a final or proposed applicable standard. CAA § 111(a)(2) (emphasis added) (defining "new source" for purposes of NSPS program).

Neither "construction" nor "modification" encompasses the reconstruction of a stationary source. Reconstruction of a facility frequently does not lead to an increase in emissions, which is necessary for a refurbishment to be deemed to be a "modification" under the Act. *Id.* § 111(a)(4) (If the "reconstruction" does lead to an increase in emissions, it is subject to the standard of performance as a modification.). And while Section 111 does not define "construction," the plain meaning of the term is "the creation of something new, as distinguished from the repair or improvement of something already existing," which clearly excludes replacement of components at an existing facility. *United States v. Narragansett Improvement Co.*, 571 F. Supp. 688, 693 (D.R.I. 1983) (holding that replacement of major components at a facility was not "construction" under § 111). Plainly, rebuilding half (50%) of a facility does not result in a "new" facility. Just like replacing the electronic control board of an existing washing machine does not turn it into a new washing machine, even if the replacement board costs half the value of a new machine.

In contrast, where Congress desires to provide EPA authority to regulate reconstructed sources, it has done so explicitly. *See* CAA § 112(a)(4) (defining "new source" for purposes of hazardous air pollutant standards as "a stationary source the construction or reconstruction of which" is commenced after proposed standard's publication).[11] When a statute grants authority in explicit terms, courts generally interpret Congress's silence in other provisions of the statute to withhold that authorization. *See Ethyl Corp. v. EPA*, 51 F.3d 1053, 1061-62 (D.C. Cir. 1995) (refusing to imply CAA authorized EPA to consider public health under one provision where Congress granted same authority explicitly elsewhere in the Act); *City & County of San Francisco v. EPA*, 145 S. Ct. 704, 714 (2025) (finding that all "limitations" imposed under one section of the Clean Water Act are not impliedly "effluent limitations" where Congress has elsewhere referred expressly to "effluence limitations" in the statute). Congress did not implicitly give EPA the authority to regulate reconstructed sources under Section 111 that it chose to explicitly give under Section 112.

For these reasons, the reconstruction rule at § 60.15 is unlawful and should be repealed.

2. The Proposal has constructively reopened the NSPS reconstruction rule for review.

The statutory time period to petition for review of EPA's original promulgation of the reconstruction rule (in 1975) has certainly long passed. *See* CAA § 307(b)(1) (requiring any petition for review of a Section 111 standard to be filed within 60 days of the standard's promulgation). By proposing the present revisions to the reconstruction rule, however, EPA has constructively reopened the issue of whether it has the statutory authority to regulate reconstructed sources under Section 111. Constructive reopening occurs where the agency "adhere[s] to the *status quo ante*" rule despite a "'change in the regulatory context.'" *Sierra Club v. EPA*, 551 F.3d 1019, 1025 (D.C. Cir. 2008) (quoting *Kennecott Utah Copper Corp. v.*

[11] Congress provided EPA authority to regulate reconstructed sources in § 112 in the CAA Amendments of 1990. Simultaneously, it rewrote much of § 111 without providing EPA authority to regulate reconstructed units under the NSPS program.

Dep't of the Interior, 88 F.3d 1191, 1214 (D.C. Cir. 1996)). The previously time-barred agency action is reopened to judicial review if "the revision of accompanying regulations 'significantly alters the stakes of judicial review' as the result of a change that 'could have not been reasonably anticipated.'" *Id.* (quoting *Kennecott*, 88 F.3d at 1227; *Envtl. Def. v. EPA*, 467 F.3d 1329, 1334 (D.C. Cir. 2006)). The D.C. Circuit applies a four-part test to determine whether an agency has constructively reopened a rule: whether the agency has "(1) proposed to make some change in its rules or policies, (2) called for comments only on new or changed provisions, but at the same time (3) explained the unchanged, republished portions, and (4) responded to at least one comment aimed at the previously decided issue." *Pub. Citizen v. Nuclear Reg. Comm'n*, 901 F.2d 147, 150 (D.C. Cir. 1990).

Here, EPA has proposed to: (1) dramatically change the context in which the reconstruction rule applies by directing it towards only a portion of a facility, as opposed to the entire facility as originally contemplated; (2) called for comments only with respect to the simple-cycle portion of a combined-cycle facility, and not to the facility as a whole as was originally contemplated by the reconstruction rule; and (3) explained the reconstruction rule in terms of its applicability to the simple-cycle portion of a facility. Furthermore, EPA satisfies the underlying purpose of constructive reopening. EPA's proposed revisions to Subpart KKKK dramatically alter the effect and scope of the reconstruction rule in a way that could not have been foreseen at the time of its promulgation.

Although EPA's proposal does not change the text of the existing reconstruction rule at § 60.15, the proposed revisions to be included in Subpart KKKKa will completely change the way that rule is applied to stationary CTs by focusing the reconstruction analysis solely on the simple-cycle portion of a combined-cycle facility rather than the entire affected facility was originally contemplated. When the reconstruction rule was adopted in 1975, its purpose was to identify circumstances in which refurbishments of a source are "substantially equivalent" to replacing the source with "a newly constructed affected *facility*." 40 Fed. Reg. at 58,417 (emphasis added). To that end, the current reconstruction test considers the fixed capital cost of a "comparable entirely new facility." 40 C.F.R. § 60.15(b)(1). EPA's proposed revisions, which limit the analysis to the cost of the simple-cycle portion of the facility (or even just the turbine engine, if the preamble is to be believed) would divorce the reconstruction analysis from the regulated facility as a whole for the first time in the five decades history of the NSPS. The resulting rule would classify limited refurbishments to a small part of the combined-cycle affected facility as substantially equivalent to constructing an entirely new combined-cycle facility, a deviation from the original purpose and application of the reconstruction rule that would not only distort the basic meaning of the term "reconstruction" but represent a revolutionary change to the regulatory context. In other words, historically, an owner or operator would have to engage in a very high level of activity (at least 50% of the cost of a brand-new facility) to trigger the reconstruction rule. Here, replacing much less—50% of just a component of the affected facility—would be deemed reconstruction. This is nonsensical in light of the rule's original intent and will lead to a dramatic shift in NSPS applicability the energy industry cannot reasonably accommodate.

This change would significantly alter the threshold for subjecting existing turbines to new regulatory requirements. Many facilities will become subject to Subpart KKKKa as a result of refurbishments that would not have satisfied the reconstruction test within the present regulatory context. For those owners and operators, the reconstruction rule "'may not have been worth challenging in [1975], but the revised regulations gave [that rule] a new significance.'" *Sierra Club*, 551 F.3d at 1026 (quoting *Kennecott*, 88 F.3d at 1227).

Moreover, the proposed revisions could not have been reasonably anticipated when the existing reconstruction rule was promulgated, because EPA's stated purpose of identifying refurbishments that are substantially equivalent to construction of an entirely new facility did not give "adequate notice or incentive to contest" the rule's future application to just one component of a facility. *Nat'l Ass'n of Mfrs. v. Dep't of the Interior*, 134 F.3d 1095, 1104 (D.C. Cir. 1998). Where an agency changes the regulatory context in a manner that unexpectedly broadens the applicability of an existing rule, that agency constructively reopens the rule to judicial review. *See id.* ("'Before any litigant reasonably can be expected to present a petition for review of an agency rule, he first must be put on fair notice that the rule in question is applicable to him.'") (quoting *Recreation Vehicle Indus. Ass'n v. EPA*, 653 F.2d 562, 568 (D.C. Cir. 1981)). EPA's proposed revisions would do just that by fundamentally changing the reconstruction analysis for Subpart KKKKa turbines in a way that was unforeseeable when the existing rule was adopted.

B. Even if the general reconstruction provision is not subject to review, or even if it is lawful, EPA has no authority to promulgate the proposed reconstruction provision in the Proposal.

Even if the 1975 general reconstruction provision must remain on the books because it is not subject to review, the specific reconstruction provisions proposed here for CTs are unlawful because EPA has no authority to mandate application of the reconstruction rule in this way. Section 307(b)(1) of the CAA sets time limits on review of a specific rule promulgated or final action taken by EPA. Therefore, even if 40 C.F.R. § 60.15 is, in and of itself, not subject to review, it does not make the concept of reconstruction lawful. Even though EPA has previously applied new performance standards to "reconstructed" facilities cabined by certain purposes and limits, and CAA § 307(b)(1) dictates that those previous rules and actions are not subject to review, this Proposal is a new agency action, and it seeks to apply a NSPS to CT facilities that are neither new nor modified. EPA has no such authority under the statute, even if it previously claimed, and no party challenged, such authority. This new action and the reconstruction provisions of the Proposal are, therefore, subject to objection because they are unlawful (for the reasons discussed above in Part V.A.1), and should therefore not be finalized for that reason. EPA should apply the proposed performance standard under KKKKa to new and modified CTs only as instructed by Section 111 of the Act. Put simply, there is no such a thing as reconstruction under Section 111, as discussed in the preceding section.

Moreover, even if EPA has authority to apply NSPS to "reconstructed" units as defined in the 1975 rule—i.e., whenever the replacement cost is more than 50% of the cost of a new facility—the specific provisions in this Proposal basing reconstruction of a combined-cycle affected facility on the "simple-cycle portion" of the facility exceed even that authority.

The reconstruction rule has since its inception in 1975 been applied to the entire affected facility that has been defined for purposes of the relevant NSPS. This approach is rational because "reconstruction," according to the 1975 preamble, reflects an amount of work that is tantamount to constructing an entirely new affected facility. 40 Fed. Reg. 58,416, 58,417. In other words, the only possible, lawful basis of applying a new standard to a "reconstructed" source under a statute that authorizes the application of such a standard only to new and modified sources is that a reconstructed source is, effectively, a new source. By contrast, the proposed rule would apply the reconstruction concept to only a small portion of the affected facility (less than 50% in terms of cost) and could in no terms be understood as tantamount to constructing an entirely new facility. Such Orwellian "NewSpeak" can be accepted only if the statutory term "new" is so malleable that EPA can give it whatever meaning it wants.[12]

A project that refurbishes only a portion of an *existing* affected facility, especially at less than 50% of the cost of a new facility, is a physical change to the *existing* facility. If that change increases emissions, it is a modification of the *existing* facility, and the modified facility becomes subject to the proposed performance standard. No amount of linguistic gymnastics can turn this *existing* facility to a new one under Section 111.

C. The proposed reconstruction provision in the Proposal is arbitrary and capricious.

The proposed reconstruction provision is also arbitrary and capricious because EPA failed to consider an important aspect of the problem. *See State Farm*. In attempting to justify this new, peculiar definition of reconstruction for combined-cycle affected facilities, EPA says: "The purpose of the [reconstruction provision] is to ensure that sources that undertake sufficiently large capital investments as to effectively be 'new' sources are required to invest in emissions controls as well, and do not avoid performance standards that would otherwise apply to new sources." 89 Fed. Reg. at 101,314; *cf. Wisconsin Elec. Power Co. v. Reilly*, 893 F.2d 901, 909 (7th Cir. 1990) (quoting *National-Southwire Aluminum Co. v. EPA,* 838 F.2d 835, 843 (6th Cir.) (Boggs, J., dissenting) ("'The purpose of the "modification" rule is to ensure that pollution control measures are undertaken when they can be most effective, at the time of new or modified construction.'") (internal citation omitted).

[12] Even if the Agency might have prevailed on such a stretched interpretation of the term "new" under *Chevron*, which we doubt given the plain meaning, those days are gone. *See Loper Bright*, 603 U.S. 369, 412 (2024).

In the rulemaking, however, EPA does not recognize that the standard it has proposed—in particular for combined-cycle affected facilities, which almost invariably consist of large CTs operating at base load—requires an SCR. SCRs at combined-cycle units are installed within the HRSG, not at the simple-cycle portion of the facility, because the velocity and temperature of the exhaust gases at that location in the HRSG would have reduced enough to allow the effective use of an SCR. In short, under the Proposal, a combined-cycle affected facility that would be "reconstructed" because it did substantial work at the simple-cycle portion of the unit would have to also do even more substantial work at the HRSG, the portion of the facility that is otherwise untouched, to install the controls the proposed standard of performance would require for the reconstructed facility. This result is illogical, goes directly against Congressional intent that the reconstruction project presents an opportune time for pollution control measures to be "undertaken when they can be most effective, at the time of new or modified construction," *cf. Wisconsin Elec. Power Co. v. Reilly*, 893 F.2d at 909, and in any event was not considered by EPA. Most notably, as discussed in Part V (in connection with modified combined-cycle facilities), retrofitting an SCR into an existing HRSG is physically challenging, and if undertaken would cost considerably more than an SCR integrated into the design and construction of a new HRSG. 89 Fed. Reg. at 101,338. There is no analysis of either the feasibility or the cost of such a massive undertaking in the record.

For these reasons, the proposed reconstruction provision for combined cycle affected facilities is arbitrary and capricious.

VI. EPA's Proposal to Base Whether an Affected Facility Is "New" on the "Simple-Cycle Portion" of Combined-Cycle Facility Is Also Unlawful and Arbitrary and Capricious.

The proposed provision discussed above for reconstruction of a combined cycle affected facility also applies to the determination of whether a facility is "new." Proposed 40 C.F.R. § 60.4305a(b) provides:

> For the purpose of this subpart, only the simple cycle portion of a combined cycle … stationary combustion turbine is used to determine whether the affected facility is new or reconstructed. When determining if a facility is new or reconstructed, do not include the equipment associated with the HRSG, as included in the definition of a stationary combustion turbine.

For largely the same reasons as in the preceding two subparts (Parts V.B and V.C) in connection with "reconstruction" of a combined cycle affected facility, this provision is also unlawful as to "new" affected facilities. In a nutshell, especially outside the use of the "reconstruction" concept (which is unlawful, as discussed above), EPA has no authority to decree by administrative fiat that construction of a *part* of an affected facility is heretofore an entirely *new* facility. Words have meaning, and a *part*-new combined-cycle affected facility is not a *new* combined-cycle affected facility. Moreover, just as in the case of reconstruction, EPA's truncated definition of "new" for a combined-cycle facility would require an *existing* HRSG that is otherwise untouched to undergo substantial work to install controls because another component of the facility (e.g., one of the turbines in the simple-cycle portion) is new. As explained above, this result is illogical, goes directly against Congressional intent, and in any event was not considered or analyzed by EPA.

EPA has no authority to, and it should not, finalize proposed 40 C.F.R. § 60.4305a(b).

VII. Monitoring and Reporting Issues

PGen's comments on monitoring, reporting, and recordkeeping issues are set forth in the memorandum included herein as Attachment B from Agora Environmental Consultants. *See* Memorandum from S. Norfleet & M. O'Connell to Power Generators Air Coalition, *Comments on the Proposed "Review of New Source Performance Standards for Stationary Combustion Turbines and Stationary Gas Turbines" Revisions to Subparts KKKKa, KKKK, and GG of 40 CFR Part 60 (Docket # EPA–HQ–OAR–2024–0419)* (April 14, 2025).

Dated: April 15, 2025

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Attachment A

Technical Basis for Comments:
New Source Performance Standards
for Stationary Combustion Turbines and Gas Turbines

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April 14, 2025

Table of Contents

List of Figures, Tables

i. Summary

This report provides comments on aspects of the Environmental Protection Agency (EPA) December 13, 2024 proposed revision to New Source Performance Standards (NSPS) for nitrogen oxides (NOx) emissions for new combustion turbines, as well as such turbines that are "modified" or "reconstructed".

Comments are presented according to seven categories. The first category concerns the existing combustion turbine population. Our analysis finds that EPA's construction of the combustion turbine population database reflects units devoted to utility power generation in one respect. Units with heat throughput less than 250 million British thermal units per hour (250 MMBtu/h), or approximately 25 megawatts (MW) of output are not addressed in this report, as few are deployed for utility power generation. A large number of combustion turbines, reflecting the aeroderivative category, with heat throughput between 250 and 850 MMBtu/h do provide utility power generation. Units greater than 850 MMBtu/h are typically designated as frame turbines and are also a major contributor to present and likely future utility duty. EPA does not, however, recognize important difference between four major classes of frame turbines, each of which can generate NOx emission ranging from 25 ppm to (for some cases) as low as 5 ppm. Regarding solicited comments on NOx emissions for "co-firing" of natural gas with alternative fuels, the U.S. Energy Information Administration (EIA) reports indicate few units contemporaneously fire fuel oil and natural gas; fuel oil although used, is mostly directed for startup or as an occasional backup fuel. Regarding co-firing of hydrogen, numerous short-term demonstration tests have been conducted on combustion turbines but NOx emissions data either on a concentration basis or mass rate are not publicly available. Consequently, any attempt to establish a NOx emission standard for hydrogen firing (and co-firing) is premature.

A second category is EPA's proposal for an alternative mass-based output limit of NOx emissions, in terms of tons emitted per MW of generating capacity, over a calendar year. EPA proposed a range of mass emission rates– from 0.25 to 0.75 tons per MW per calendar year – but even the highest rate constrains operation, essentially severely limiting utilization of the power generating asset. Depending on the assumed NOx emissions rate at part load (less than 70% of rated capacity[1]) and high load (greater than 70% rated capacity), a mass-based output limit can in many cases restrict annual capacity factor to less than 20%. Such a constraint prevents combustion turbines from operating as needed to balance the non-dispatchable resources in the grid and improve electric reliability.

A third category addresses EPA's concern that owners will intentionally operate combustion turbines at part load to avoid investment to meet high load NOx limits. There is no economic

[1] This discussion presumes the "rated capacity" of a combustion turbine is the nameplate generation for ISO conditions of 15°C (59°F), 101.325 kPa (14.7 psia), and 60% relative humidity. In terms of heat input, the rule refers to the turbine's capacity as "base load rating."

incentive to do so – in fact, such actions incur a cost penalty. Limiting duty to part load – essentially forgoing all revenue for duty at greater than 70% of capacity for the lifetime of the unit - significantly restricts revenue and provides only minor cost savings. In the present market, high load duty is required for both medium and large combustion turbines. Units at the population mid-point expend 75-80% of operating time at high load. Thus, any means to limit operation interferes with actions to balance the generating grid.

A fourth category is the achievability of proposed high load NOx emission rates of 2 and 3 parts per million (ppm), feasible only by deploying selective catalytic reduction (SCR) NOx control.[2] First, the calculations supporting EPA's conclusions as to the feasibility of compliance for 2, 3, and 4 ppm limits could not be replicated for all cases by this study. The results are disparate – several cases of "100%" compliance are replicated, but for a number of cases this study reports a lower frequency of compliance. There are also cases where this analysis predicts a higher frequency of compliance than EPA. Regardless, both analyses show a significant shortfall in compliance frequency for the 2 ppm standard, as less than half of cases are successful. Compliance frequency is higher with a 3 ppm limit but the margin is small. These results suggest uncertainty in meeting even the 3 ppm standard while abiding by acceptable levels of residual ammonia (NH_3).

A fifth category describes the challenge of designing and operating SCR process equipment for part load duty. SCR technology has evolved to be reliable and effective but critically contingent upon providing proper process conditions at the catalyst inlet. These process conditions include a uniform distribution of gas flow velocity, high (but generally not exceeding 850 degrees Fahrenheit, ºF) gas temperature to prompt catalyst activity, and most important a uniform distribution of ammonia reagent and NOx (e.g. NH_3/NOx ratio). Achieving high NOx removal (~75% or more) requires a uniform distribution of NH_3/NOx ratio at the inlet of catalyst. At part load duty, a combustion turbine at the exit presents tortuous gas flow conditions, particularly high and variable velocity, NOx content, and temperature – conditions not conducive to uniform NH_3 and NOx. These part load conditions compromise NOx control unless high exhaust gas content of residual NH_3 is accepted.

The sixth category addresses EPA's cost evaluation to determine the levelized cost per ton of NOx removal. The EPA bases its analysis on SCR capital cost from a Department of Energy National Energy Technology Laboratory (NETL) study.[3] There are several flaws in EPA's approach. First, EPA uses in the analysis a reference unit likely not representative of future installations, and a capacity factor that does not reveal the highest cost possible. Second, the SCR capital cost for combustion turbines in simple and combined cycle duty is dated, and – as conceded with a disclaimer in the NETL reference – may not reflect present market forces. Recent SCR quotes and installations confirm it does not. Third, EPA ignores the widely divergent NOx emission from four key categories of combustion turbines – aeroderivative, E-Class, F-Class, and H-Class and similar very large turbine models. NOx emission from these

[2] EPA cites these target NOx rates assuming a content of residual ammonia in the gas of 10 ppm, at catalyst end-of-life.

[3] Cost and Performance Baseline for Fossil Energy Plants, Volume 5: Natural Gas Electricity Generating Units for Flexible Operation, NETL Report DOE/NETL-2023/3855, May 5, 2023. Hereafter NETL 2023 Cost Study.

different combustion turbine categories, using advanced combustion controls, can vary from 25 ppm to 5 ppm, significantly affecting the estimated cost per ton to control NOx.

Analysis in this report addresses EPA's shortcomings. The analysis first replicates EPA's cost methodology using a "generic" reference unit, but of lower heat throughput (2,000 MMBtu/h) and capacity factors for three categories: *low* (less than 20%), *intermediate* (20% is used in the analysis, which is the low end of the 20% to 40% range), and *base* (40% is used in the analysis, which is the low end of the greater than 40% range for base load duty). The lower heat throughput better reflects new combustion turbines likely to be installed. The revised capacity factors represent the lowest of the *intermediate* and *base* categories, reflecting the highest cost in these ranges. In addition, the evaluation considered combustion turbine exit NOx emissions over a range from 25 ppm to as low as 5 ppm, reflecting capabilities of the various classes of frame turbines. Revising this analysis to consider changes results in the levelized cost per ton to be higher than EPA's by a minimum of 50-100%; for some cases with 9 ppm and 5 ppm emissions rate, the cost per ton exceeded $25,000.

Further evaluation considered updated SCR capital cost, as experienced by several owners of simple cycle combustion turbines. These owners solicited bids for SCR process equipment, the cost for which per unit generating capacity exceed EPA's by a factor of 2 or 3. These elevated costs apply to new units, with much higher costs estimates received for retrofit to existing units. These adjustments of capital cost and NOx emissions, the latter considering between 25 ppm and 5 ppm, reveal levelized cost per ton exceeding $50,000 and for some cases several hundred thousand dollars. Consequently, this study shows EPA's methodology under-estimates both SCR capital cost and the levelized cost per ton of NOx removed.

The seventh category addresses EPA's request to identify changes to gas turbines, other than combustor upgrade or rebuild, that could potentially increase throughput. This section advises that either a compressor upgrade or the use of high volume air vanes can increase air flow. These actions if deployed contemporaneously with a combustor upgrade or a hot gas path upgrade are part of work that lowers NOx and potentially sulfur dioxide (SO_2) emissions.

SECTION 1. INTRODUCTION

The Environmental Protection Agency (EPA) on December 13, 2024, proposed amendments to the new source performance standards (NSPS) for NOx emissions from new, modified, and reconstructed stationary combustion turbines and stationary gas turbines.[4] The EPA proposed updating the requirements of Subpart KKKK for a wide variety of combustion turbines, including those used for electric power generation. Most notably, EPA has focused on altering the NOx emission standard assigned for "high-load" and "part-load" duty, as well as the threshold by which these load segments are distinguished.

The use of combustion turbines for power generation has increased significantly in recent years.[5] The combustion turbines for new application will look very different from those previously deployed. Specifically, the design of turbine components and the combustor will be capable of frequent and rapid load changes, as necessary to balance the generation grid as non-emitting resources either become available or lose delivery capability. Despite significant research and development (R&D) efforts by turbine suppliers, controlling nitrogen oxides (NOx) at extremely low loads remains very challenging.

Each of the major gas turbine suppliers has significantly evolved their technology in recent years. Most notable is the evolution of combustor technology to meet NOx limits without water injection. Design challenges persist at low load, as creating the ideal conditions for fuel and air mixing, fuel utilization, and flame temperature to limit NOx is very difficult to achieve at low load.

Combustor design is also evolving to fire hydrogen, either exclusively or in a blend with natural gas. Each of the suppliers has made progress in doing so, although as summarized in recent reviews, the commercial experience is limited to short term tests or the use of refinery off-gas, the latter not exclusively hydrogen.[6,7]

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[4] 89 Fed. Reg. 101306 (December 13, 2025) (Proposal).

[5] Gas Turbine Market Forecast, March 21, 2024. See https://gasturbineworld.com/market-forecast/

[6] Emerson, B. et. al., Assessment of Current Capabilities and Near-Tem Availability of Hydrogen-Fired Gas Turbines Considering a Low Carbon Future, Proceedings of the ASME Turbo Expo 2020: Turbomachinery Technical Conference and Exposition GT 2020, June 22-26, 2020, London, England.

[7] Comments of the Electric Power Research Institute on Environmental Protection Agency EPA-HG-OAR-2014-0128; FRL-5788-02-OAR, Review of New Source Performance standards (NSS) for Stationary Combustion Turbines and Stationary Gas Turbines - Proposed Rule, March 13, 2025.

This report is organized into seven sections. After this Introduction, the database used by EPA to distinguish between turbine categories and fuel use is reviewed in Section 2. Section 3 addresses EPA's proposed alternative mass-based output limit. Section 4 addresses part load duty. Section 5 reviews the achievability of meeting NOx limits of 2 and 3 parts per million (ppm) that require the use of selective catalytic reduction (SCR). Section 6 reviews the design steps required to deploy SCR over a broad load range, including startup and part load. Section 7 critiques EPA's cost evaluation, and Section 8 identifies an upgrade to combustion turbine equipment that when deployed with a combustor or hot gas path upgrade, can be part of work that lowers NOx and potentially sulfur dioxide SO_2 emissions.

SECTION 2. DATABASE OF GENERATING ASSETS AND FUEL CAPABILITY

The EPA categorizes the population of combustion turbines based on heat throughput reported to the U.S. Energy Information Administration (EIA).[8] The EPA defines units of "small" capacity as those with a heat throughput of less than 250 MMBtu/h, while those capable of a heat throughput between 250 MMBtu/h and 850 MMBtu/h are designated of "medium" capacity. Combustion turbines capable of firing greater than 850 MMBtu/h are designated "large." This report focuses on combustion turbines used in the electric power industry. Combustion turbines used in the electric power industry rarely process heat throughput less than 250 MMBtu/h, corresponding to approximately 25 MW output. More typical are units with heat throughput between 250 MMBtu/h and 850 MMBtu/h, corresponding to approximately 90 MW. Most combustion turbines in the electric power industry that are smaller than 60 MW are of "aeroderivative" design – that is, adapted from turbines initially designed for propulsion. Most combustion turbines intended for power generation with a rated capacity greater than this 60 MW threshold are called "frame" turbines. Within the latter category, several frame classes exist reflecting size, combustor firing temperature, and materials of construction. Specifically, combustion turbines of Class E, F, and H generally reflect higher firing temperature and refinement to the hot gas path that improve output.

This analysis reviews EPA's categorization considering the EIA data, which although informative does not distinguish between the different large turbine frame types. The population distribution of both simple and combined cycle units is evaluated, and considered in the context of utility applications.

Total Unit Population

Figure 2-1 presents the population distribution of existing gas turbines of 25 megawatts (MW) or greater, according to nameplate generating capacity (in MW).[9] A total of approximately 2,850 units exceed 25 MW. Figure 2-1 shows that the mid-point of the population corresponds to a generating capacity of 92 MW, roughly around EPA's designation of 850 MMBtu/h as the threshold for large combustion turbines. Figure 2-1 also reveals a cluster of approximately 250 units of about 60 MW capacity, reflecting popular aeroderivative designs. The figure also shows 90% of the combustion turbine population generates less than 200 MW; with the upper 4% of the population capable of 300 to 475 MW of capacity.

[8] Data are derived from Energy Information Administration Form 860, presuming heat throughput reported is that specified by the turbine supplier at ISO conditions.
[9] Generating capacity in megawatts is determined assuming a heat rate of 10,000 Btu/kWh for units between 250 and 850 MMBtu/h, and 9,000 Btu/kWh for units exceeding 850 MMBtu/h.

Unit age for simple and combined cycle duty is presented in Table 2-1 and Figure 2-2. Table 2-1 describes for simple and combined cycle units the turbine population according to five intervals of years, while Figure 2-1 graphically presents the information as a fraction of the population.

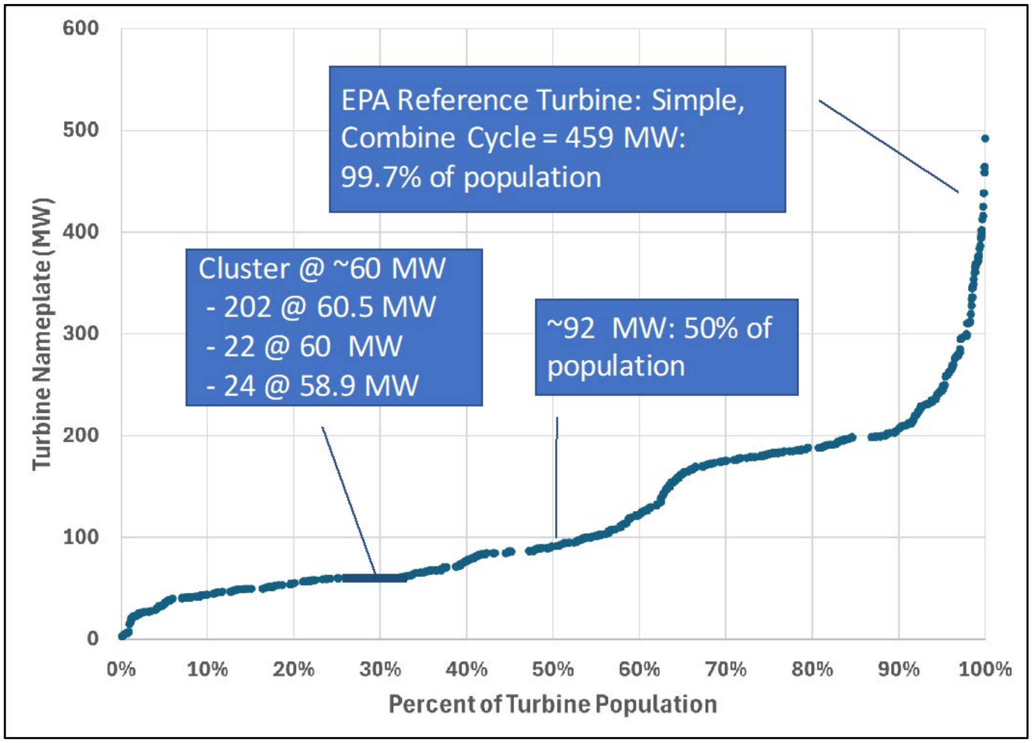

Figure 2-1. Combustion Turbine Population Distribution, by Nameplate Capacity

Table 2-1. Combustion Turbine Population By Age: Simple and Combined Cycle

Unit Age (Years)	Combined Cycle	Simple Cycle	Total
0-4	24	72	96
5-9	62	70	132
10-19	105	251	356
20-29	317	802	1,119
30+	148	511	659
Total	24	1,706	2,362

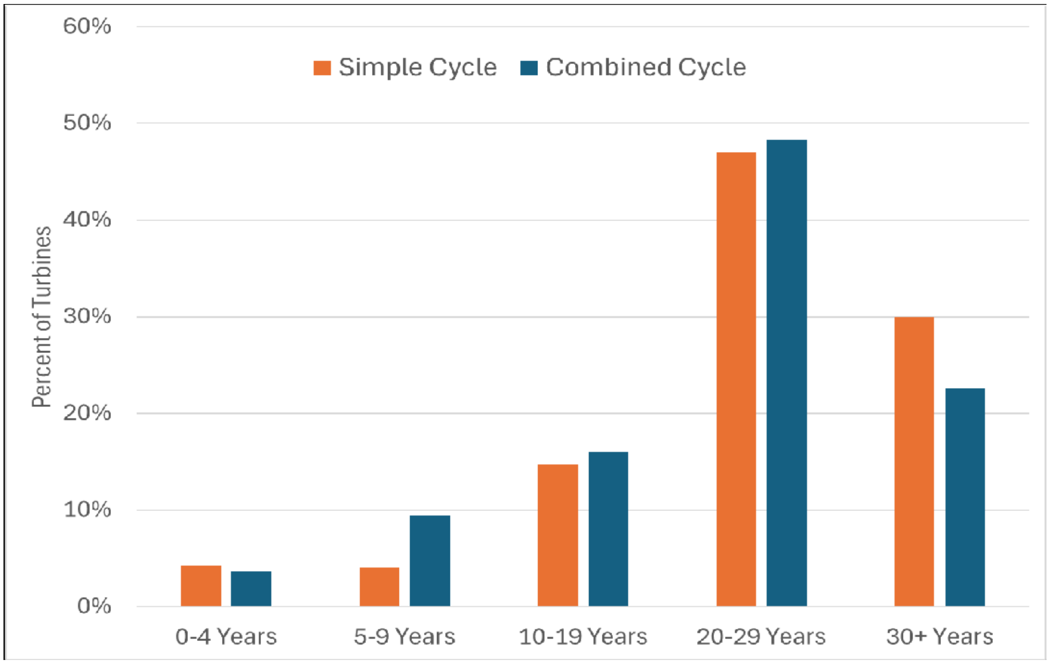

Figure 2-2. Combustion Turbine Population: Percentage by Age for Simple, Combined Cycle

The number of combustion turbines within defined increments of generating capacity is described by Figures 2-3 and 2-4 for simple and combined cycle applications. Figure 2-3 shows that the largest number of simple cycle units falls between 48 and 71 MW, approximately 640 units. Figure 2-4 shows that the largest number of combined cycle units falls between 178 and 213 MW, exceeding 400 units.

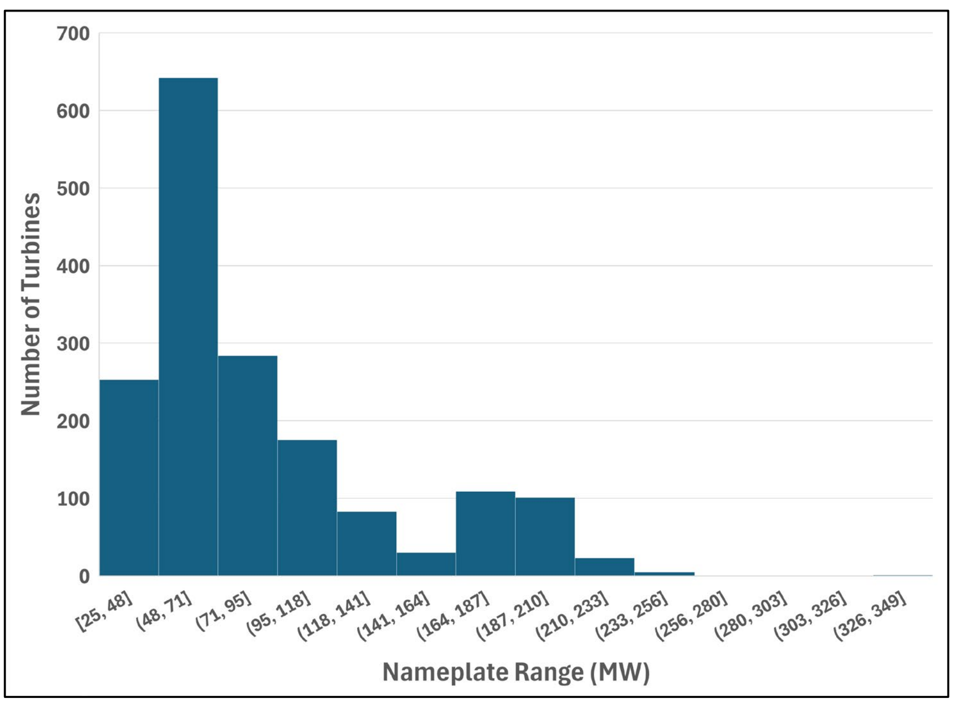

Figure 2-3. Population of Combustion Turbines by Nameplate: Simple Cycle Duty

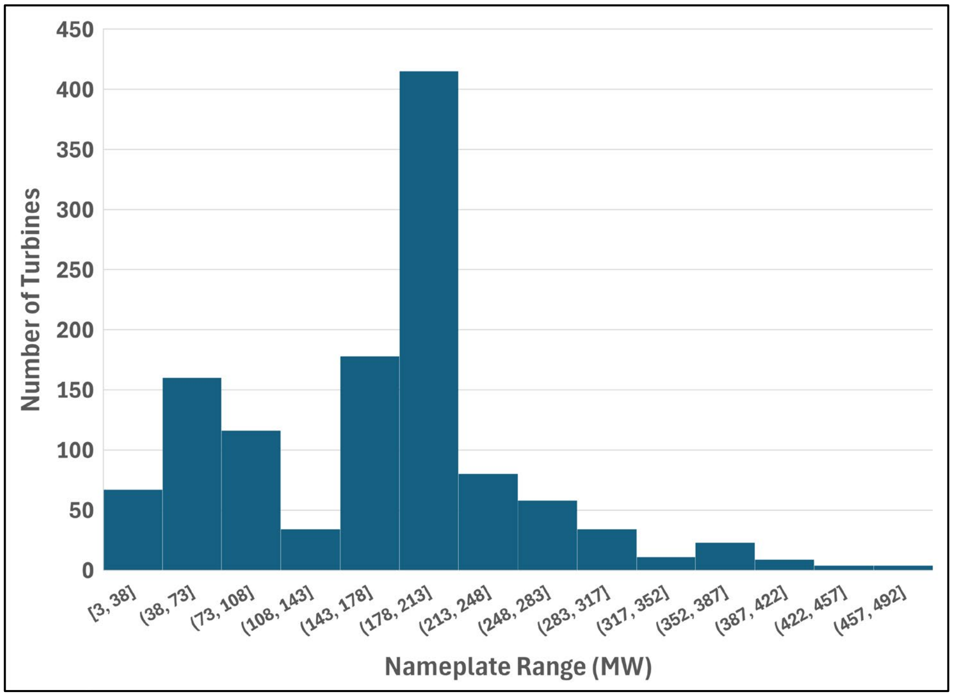

Figure 2-4. Population of Combustion Turbines by Nameplate: Combined Cycle Duty

EPA's proposed categorization of units by generating capacity thus appears to distinguish between the medium and large turbine population. The medium category encompasses primarily aeroderivative combustion turbines—typically used almost exclusively in simple-cycle configuration—and the large category addresses frame turbines, both simple cycle and combined cycle. EPA's proposed categorization, however, fails to distinguish between the four different classes of frame turbines, which have very different NOx emissions without an SCR.

Fuel Utilization

EPA solicited comments on NOx emissions from multiple fuels, including hydrogen. Comments are offered in this section.

Multiple Fossil Fuels

Many combustion turbines are designed for multiple fuel use, either for startup or backup duty in the event of loss of the main fuel supply (which is almost always natural gas). The annual fuel use of the population is reported in EIA Form 860. For combustion turbines in combined cycle application, a total of 22% of units (267 of 1193) report capability to switch between fuel oil and natural gas, while for simple cycle units a total of 37% (633 of 1706) report the same. Almost without exception, fuel oil and gas are not contemporaneously fired – the state-of-the-art dry low NOx combustors are not capable of managing the injection, mixing, and volatilization of liquid fuel while minimizing NOx and particulate matter. Fuel oil is used for startup or as an alternative fuel if supplies of natural gas are curtailed, or cost prohibitive.

A total of 177 combustion turbines reported being capable of "co-firing" describe firing natural gas and, depending on availability, a secondary gaseous fuel such as refinery off-gas or renewable natural gas (biogas).

Hydrogen

Each of the major combustion turbine suppliers are developing advanced combustors capable of firing hydrogen, while attempting to arrest any increase in NOx emissions due to the higher flame temperature. However, at present none of these suppliers have released quantitative data describing NOx emissions with hydrogen, except to say generally that such emissions should not be higher than what would be achieved with natural gas. More important, almost all data is short-term – recorded over hours of operation. The following summaries are noted:

- Mitsubishi Hitachi Power Systems reports results from the 501J turbine, featuring the "multi-cluster" combustor with 30% firing hydrogen capability, but claims the capability to "…maintain emissions compliance capability with hydrogen blend."[10]

- The New York Power Authority noted that co-firing hydrogen by up to 35% in a GE LM6000 SAC increased NOx by 24%, remedied by adjustments to the NOx control means (water injection); this result will not be applicable to dry low NOx combustors.[11]

- GE completed tests at Long Ridge Energy Generation, monitoring performance from a 485 MW combined cycle unit featuring a 330 MW 7HA.02 gas turbine. This test evaluated a 5% blend of hydrogen (by volume) in March of 2022, operating for an undisclosed period. NOx emissions have not been publicly disclosed.[12]

- Siemen report results with 270 MW SGT6-6000G turbine, firing 39% hydrogen, reporting NOx equivalent to natural gas (25 ppm at 15% O2).[13]

- Ansaldo describes the NOx control capability of its sequential combustion systems such that emissions "…can be brought down to very low levels" but does not cite quantitative values.[14]

As EPA is aware,[15] the conventional metric of NOx as a concentration (ppm) in combustion products is not a valid means to compare emissions between hydrogen and natural gas, as the

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[10] *Taking Gas Turbine Hydrogen Blending to the Next Level*, EPRI, September 2022.

[11] *Hydrogen Co-firing Demonstration at New York Power Authority's Brentwood Site: GE LM 6000 Gas Turbine*, September 2022.

[12] https://www.powermag.com/first-hydrogen-burn-at-long-ridge-ha-class-gas-turbine-marks-triumph-for-ge/

[13] *Constellation Completes Hydrogen Blending Test at Alabama Gas-fired Plant*, Power Engineering, May 24, 2023. Available at https://www.power-eng.com/news/constellation-completes-hydrogen-blending-test-at-alabama-gas-fired-plant/#gref.

[14] https://www.powermag.com/ansaldo-energia-reports-hydrogen-breakthrough-for-gas-turbine-sequential-combustion-technology/.

[15] 89 Fed. Reg. at 101338. Footnote 52.

background combustion products differs. NOx for hydrogen firing should be reported on a mass-rate basis or a correction factor applied for a concentration basis.[16]

Conclusions

The following concluding observations drawn are:

- EPA's categorization of combustion turbines as medium and large seems to reflect the power industry's population of turbines, in one respect recognizing roughly the distinction (and different characteristics) between aeroderivative-class and frame units.

- EPA's categorization of all frame turbines in a generic "large" subcategory does not distinguish between main classes of units with substantially different characteristics: E-class units (majority at approximately 90-150 MW); F-class units (majority about 200-315- MW); and the largest, H-class units (as large as about 570MW).[17]

- Almost without exception, combustion turbines do not fire fuel oil and natural gas contemporaneously, a trend that will continue in new state-of-art combustors that are designed for low NOx conditions without water injection. Data from EIA Form 860 does reveal that a total of 177 units out of the population of approximately 2,500 are capable of contemporaneously firing alternative fuels. These appear to be mostly gas phase – such as refinery off-gas and renewable natural gas (e.g. biogas).

- The limited commercial experience with hydrogen does not provide a basis for EPA to set NOx limits. Each of the major combustion turbine suppliers developing means of hydrogen firing has not reported specific NOx emission rates – either on a mass basis or concentration basis (corrected for the change in hydrogen gas composition). The lack of publicly available data prevents confidently predicting NOx production rate capabilities.

[16] *Taking Gas Turbine Hydrogen Blending to the Next Level*, EPRI, September 2022.
[17] There is some overlap in the size between these various classes.

SECTION 3. CRITIQUE OF ALTERNATIVE MASS-BASED OUTPUT NOx LIMIT

The EPA has proposed to replace NOx limits based on heat input – typically expressed as lbs/MMBtu, which equate to a part per million (ppm) basis.[18] The proposed alternative mass-based output is defined by the tons of NOx, normalized by unit generating capacity, accounted for over a calendar year. The feasibility of utilizing this alternative is addressed in this section.

EPA proposed five scenarios of NOx mass limits for medium and large sized gas turbines, equivalent to a 12-month capacity factor and NOx emission rate (as ppm). Table 3-1 summarizes the five scenarios proposed, and the calculation basis for each.

Table 3-1. Summary of Mass-Based Emission Rates as Proposed by EPA

Turbine	Calculation Basis: 12-Month Capacity Factor (%)	Calculation Basis: NOx ppm (4-hr standard)	Equivalent Tons NOx/MW per Calendar Year
All	>20	25	0.75
Medium	N/A	25	0.75
Medium	15	20	0.45
Large	20	15	0.45
Large	15	7	0.21

EPA contends that mass-based limits simplify the regulatory actions. However, each restricts the capacity factor of a unit, in some cases severely, thus compromising the usefulness of the investment and making these proposed limits unworkable.

Capacity Factor Limitations

Each of the five scenarios of NOx mass rate limitation restrict operation to varying degrees, but most severely for large combustion turbines. Tables 3-2 through 3-4 report the equivalent limitation to capacity factor for three scenarios of NOx mass limits of 0.75, 0.45, and 0.21 tons/MW/calendar year. These subsequent tables report the capacity factor equivalent limitation for a range of NOx emissions at both part load and high load, and the fraction of operating time at high load. In these tables, average NOx emissions at part load are assumed to range from the present KKKK rate of 96 ppm to theoretical, lower rates (for illustration purposes only) of 75 and 50 ppm. NOx emissions at high load are assumed to vary from 25 ppm to 3 ppm, the later required SCR control.

[18] NOx emissions in terms of heat input as lbs/MMBtu can be expressed on part per million (ppm) basis, using EPA-derived "f-factors" that translate heat throughput into gas volume. The conventional reporting means is referring to an oxygen (O_2) content of 15%.

Table 3-2 reports the equivalent limitation in capacity factor imposed when NOx at part load is controlled to the present KKKK limit of 96 ppm. For the most stringent limit of 0.21 tons/MW/calendar year, and controlling NOx to 3 ppm, capacity factor is restricted to 26% for operation 95% of time at high load. For the same 95% of operating time, all other high load scenarios with NOx control restrict capacity factor from 7 to 21%. The NOx mass limit of 0.45 results in up to a 56% capacity factor for 95% of time at high load and 3 ppm NOx, but imposes a 20% capacity factor limit for three-quarters of the options. The NOx mass limit of 0.75 tons/MW/yr is (of course) the least restrictive. But for that mass limit, the capacity factors of units operating as high as 80% of the time at high load are severely restricted.

Table 3-2. Maximum Capacity Factor: 0.21, 0.45, and 0.75 Mass Limit, 96 ppm Part Load NOx Rate

Part-Load PPM	Mass-based Limit 0.21 Tons/MW/Year					Mass-based Limit 0.45 Tons/MW/Year					lass-based Limit 0.75 Tons/MW/Year			
96	High Load Rate (ppm)					High Load Rate (ppm)					High Load Rate (ppm)			
High Load %	3	5	9	15	25	3	5	9	15	25	3	5	9	15
95	26%	21%	15%	11%	7%	56%	45%	32%	23%	15%	93%	75%	54%	38%
90	16%	14%	11%	9%	6%	35%	30%	24%	19%	13%	58%	51%	40%	31%
80	9%	9%	8%	6%	5%	20%	18%	16%	14%	11%	33%	31%	27%	23%
70	6%	6%	6%	5%	4%	14%	13%	12%	11%	9%	23%	22%	20%	18%
60	5%	5%	5%	4%	4%	11%	10%	10%	9%	8%	18%	17%	16%	15%
50	4%	4%	4%	4%	3%	9%	8%	8%	8%	7%	14%	14%	14%	13%

Table 3-3 presents results for the same mass limits of 0.21, 0.45 and 0.75 tons/MW/calendar year, but for an assumed 75 ppm part load NOx emissions. The limit of 0.21 NOx tons/MW/calendar year restricts capacity factor to 30% for operating 95% of time at high load, and 3 ppm NOx. All but three scenarios restrict capacity factor to less than 20%. The limit of 0.45 NOx tons/MW/calendar year about doubles the allowable capacity factors, but still restricts more than three-fourths of the options to less than 20%. The capacity factor at these conditions of well controlled NOx (3 ppm) operating 95% of time at high load is restricted to a maximum annual basis of 65%. The NOx mass limit of 0.75 tons/MW/yr is the least restrictive, but it still severely limits the capacity factor of units operating at high load at 80% or even 90% of the time.

Table 3-3. Maximum Capacity Factor: 0.21, 0.45, and 0.75 Mass Limit, 75 ppm Part Load NOx Rate

Part-Load PPM	Mass-based Limit 0.21 Tons/MW/Year					Mass-based Limit 0.45 Tons/MW/Year					lass-based Limit 0.75 Tons/MW/Year			
75	High Load Rate (ppm)					High Load Rate (ppm)					High Load Rate (ppm)			
High Load %	3	5	9	15	25	3	5	9	15	25	3	5	9	15
95	30%	24%	16%	11%	7%	65%	50%	35%	24%	16%	100%	84%	58%	40%
90	20%	17%	13%	10%	7%	42%	36%	28%	20%	14%	70%	60%	46%	34%
80	12%	11%	9%	7%	6%	25%	23%	19%	16%	12%	41%	38%	32%	26%
70	8%	8%	7%	6%	5%	17%	17%	15%	13%	11%	29%	28%	25%	22%
60	6%	6%	6%	5%	4%	13%	13%	12%	11%	10%	22%	22%	20%	18%
50	5%	5%	5%	4%	4%	11%	11%	10%	10%	9%	18%	18%	17%	16%

Table 3-4 presents results for an assumed, theoretical part load NOx rate of 50 ppm and the same three mass limits. These conditions limit capacity factor to less than 37% for units operating at 95% of time at high load, with 3 ppm NOx. All but three of the operating options at 0.21 NOx tons/MW/calendar year are limited to less than 20% capacity factor, while for 0.45 tons/MW/Yr about half of the cases are limited to less than 20% capacity factor. Similar to other cases, a mass limit of 0.75 tons/MW/Yr severely limits the capacity factor of units to 80% at high load.

Table 3-4. Maximum Capacity Factor: 0.21, 0.45, and 0.75 Mass Limit, 50 ppm Part Load NOx Rate

Part-Load PPM	Mass-based Limit 0.21 Tons/MW/Year					Mass-based Limit 0.45 Tons/MW/Year					lass-based Limit 0.75 Tons/MW/Year			
50	High Load Rate (ppm)					High Load Rate (ppm)					High Load Rate (ppm)			
High Load %	3	5	9	15	25	3	5	9	15	25	3	5	9	15
95	37%	28%	18%	12%	8%	80%	59%	39%	26%	16%	100%	99%	65%	43%
90	26%	21%	15%	11%	7%	56%	45%	33%	23%	16%	93%	75%	55%	39%
80	16%	14%	12%	9%	7%	35%	31%	25%	20%	14%	58%	51%	42%	33%
70	12%	11%	9%	8%	6%	25%	23%	20%	17%	13%	42%	39%	34%	28%
60	9%	9%	8%	7%	6%	20%	19%	17%	15%	12%	33%	31%	28%	25%
50	8%	7%	7%	6%	5%	16%	16%	15%	13%	11%	27%	26%	24%	22%

The following observations per EPA's proposed mass NOx rate are offered:

- EPA's proposed mass-based output limits impose strict operating barriers on commercial units which would interfere with a unit's ability to deliver power and balance the grid. The use of any of the mass-based limits proposed by EPA would impose such low limits which would compromise grid reliability.

- Even large units that are equipped with stringent NOx control technology will be severely limited in operation at the proposed limit of 0.21 tons/MW/yr. As an example, an SCR-equipped unit operating at high load for 95% of time and emitting 3 ppm at high load (i.e., likely a highly-efficient, highly-controlled combined cycle unit) and a theoretical 50 ppm at part load is restricted to a 37% capacity factor. This same combustion turbine without SCR and emitting, for example, 9 ppm of NOx at high load is limited to less than 18% capacity factor.

- At 0.45 NOx tons/MW/yr, the same large SCR-equipped combustion turbine emitting a theoretical 50 ppm at part load and operating for 90% of time at high load while emitting 3 ppm, is limited to 56% capacity factor – negating approximately half of its value from the wholesale power market. The imposed limit to this capacity factor is more severe if the combustion turbine supplier is able to meet a theoretical 75 ppm at part load; even with SCR controlling NOx to 3 ppm for 90% of operating time, capacity factor is limited at 42%. The limit of 0.75 tons/MW/Yr also severely limits capacity factors.

SECTION 4. PART LOAD OPERATION

Section 4 addresses EPA's concern that owners will intentionally operate unit at part load (less than 70% capacity) to avoid meeting the lower NO emission rates required for high load.

In the preamble of the proposed rule, EPA expresses concern regarding a "… *regulatory incentive for owners/operators to reduce operating loads so that the part-load standard is applicable."* Section 4 shows that such actions are commercially unrealistic due to significant cost consequences of restricting operation. Section 4 also describes how simple cycle units operate in the present marketplace and presents results of a cost evaluation addressing EPA's concern.

Present Simple Cycle Duty

Simple cycle combustion turbines operate in the present wholesale power marketplace as peakers. These units startup relatively frequently, get to high load rapidly (reported as 10 minutes for the Ocotillo units), and thereafter operate primarily at high load. Minimal time is expended in transition between startup and high load. Figures 4-1 and 4-2 depict this duty for an example simple cycle unit operating at the Ocotillo power station in Arizona.

Figure 4-1 presents the duty cycle describing heat throughput over the 12 months of 2023 and shows the unit rapidly transits from startup to high load. The operating hours are shown to cluster around extremely low and high load.

Figure 4-2 presents the same data but with more clarity documenting that most operation is at less than 10% nameplate capacity, which is essentially startup, or between 90-100% of nameplate heat throughput.

The annual capacity factor for the unit as shown is approximately 18%, implying the unit operates for about 1,600 hours annually. Most units operating in simple cycle are described by a load profile as shown in Figures 4-1 and 4-2.

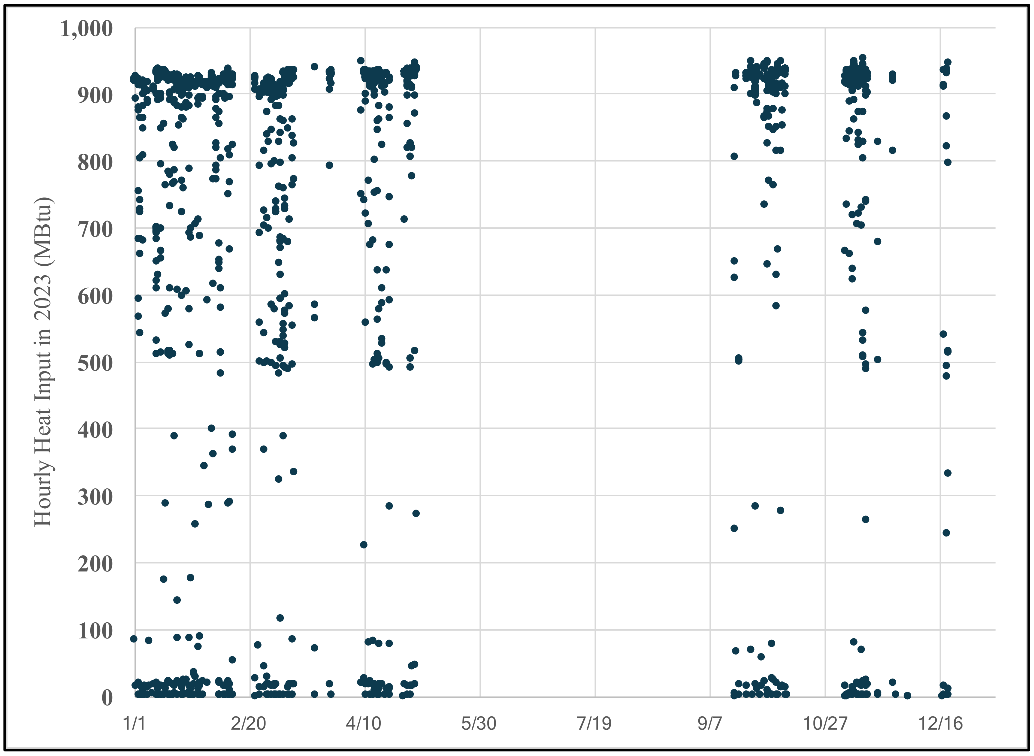

Figure 4-1. Operating Duty for an Ocotillo Simple Cycle Unit

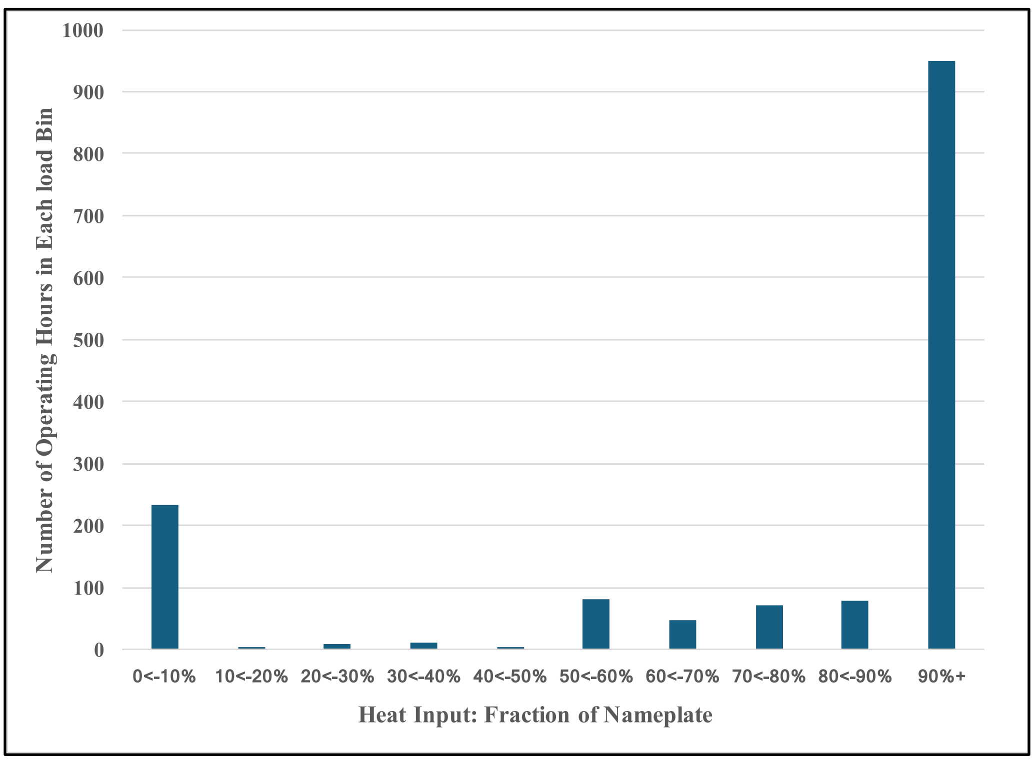

Figure 4-2. Operating Hours in Ten Load Bins: Ocotillo Example Unit

Intentional Low Load Operation to Avoid SCR

This analysis compares the revenue available for a large combustion turbine (105 MW) for two scenarios. The first scenario considers a unit not equipped with SCR that intentionally limits operation to part load duty. A second scenario considers the same unit equipped with SCR that operates, as most combustion turbines do in practice, primarily at high load. For this example, operating duty is modeled after the Ocotillo simple cycle unit represented in Figures 4-1 and 4-2.

The performance and SCR cost for the reference units are adopted from the National Energy Technology Laboratory's (NETL) simple cycle cost evaluation.[19] Table 4-1 summarizes the conditions of the analysis, including the capital cost for process equipment both with and without SCR, and the operating conditions. The two scenarios employ different heat rates, reflecting compromised thermal performance and higher fuel cost at part load.

Table 4-1. Cost Basis: Medium Simple Cycle With and Without SCR

	Capital Cost,[20] ($)	Operating Conditions
With SCR	148.7 M	• 100% capacity for 1,600 – 1,800 operating hours • Full load heat rate 8,545 Btu/kWh • Aux power for an attemperation fan[21]
Without SCR	142.8 M	• 70% capacity for 1,600-1,800 operating hours • Part load heat rate: (9,372 Btu/kWh)

By intentionally operating at no more than 70% load, the owner of the unit without SCR is limiting the generation and revenue.

Figure 4-3 shows net revenue for the interval of 1,600 – 1,800 operating hours for the unit without SCR, intentionally limited to part load, compared to revenue for an SCR-equipped unit. The calculation for net revenue for the SCR-equipped unit includes the annual capital charge and operating cost for the SCR process[22] and the benefit of lower fuel cost due to lower heat rate. Even with higher cost to pay for SCR, this case derives an additional $0.80M annually. An owner intentionally operating a simple cycle unit of this type without SCR will forgo this additional revenue. The contrast would be more severe for larger and combined cycle units.

Consequently, there is no financial gain to restricting operation to part load duty to avoid the capital and operating cost for SCR; in fact, there is a financial penalty to do so.

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[19] NETL 2023 Cost Study. See Case SC2A.

[20] Capital cost is expressed as Total Overnight Cost (TOC), excluding financing charges.

[21] The gas temperature exiting a combustion turbine operating in simple cycle can significantly exceed 1,000 F, well above the accepted temperature for reliable SCR catalyst lifetime. To remedy this, simple cycle SCR applications use an attemperation fan to dilute turbine exhaust with ambient air, lowering gas temperature to the conventional average of 700-800 F where SCR is more reliably applied.

[22] The SCR cost penalty considers a capital recovery period of 20 years and fixed and variable operation cost defined by NETL, a natural gas price of $1.90 /MMBtu, and a wholesale power price of $25/MWh.

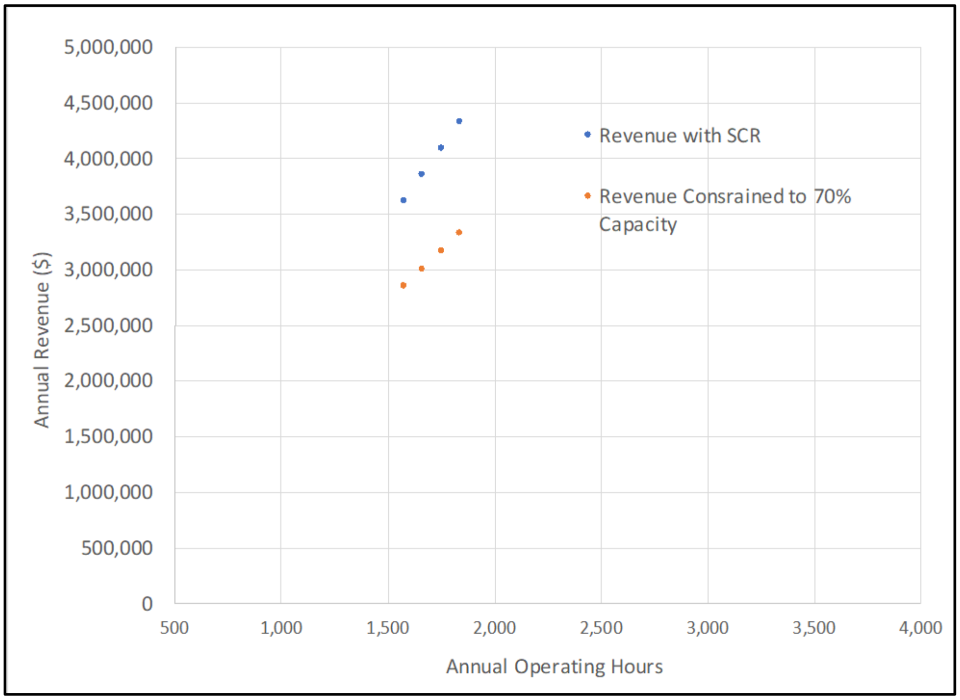

Figure 4-3. FGD Equipped Units: Role of 3-Year Capacity Factor

A significant contributor to the cost penalty is the higher capital for the generation that can be delivered to the wholesale market. Specifically, an owner following the strategy reflected in EPA's concern would be paying for capacity they never utilize. Using the same 105 MW combustion turbine generating station as reference, the capital requirement of $142.8 M equates to a normalized cost of $1,360/kW for high load duty. However, intentionally restricting the output to less than 70% of full capacity elevates the cost per usable power to $1,943/kW.

Limiting Operating Hours at Low Load

EPA inquired as to the feasibility of limiting part load operation to control NOx emissions, by requesting "comment on a maximum limit to the number of hours per year that the part-load standard can be applied."[23]

As noted in the preceding section, there is no economic benefit to intentionally restrict operation to below the high load capacity. The economic penalty is not a hypothetical calculation, as shown in Figure 4-3. The cost penalty for such actions is substantial, as shown in Figure 4-3.

Figures 4-4 and 4-5 show that, currently and in the past, some units operate at part load more than others. This is not the result of a perverse incentive that EPA suggests (currently, the most stringent high load NOx standard under KKKK is 15 ppm). Rather, if a unit is currently spending more time than another unit at part load, it is because the market demands it.

[23] 89 Fed. Reg. 101,320.

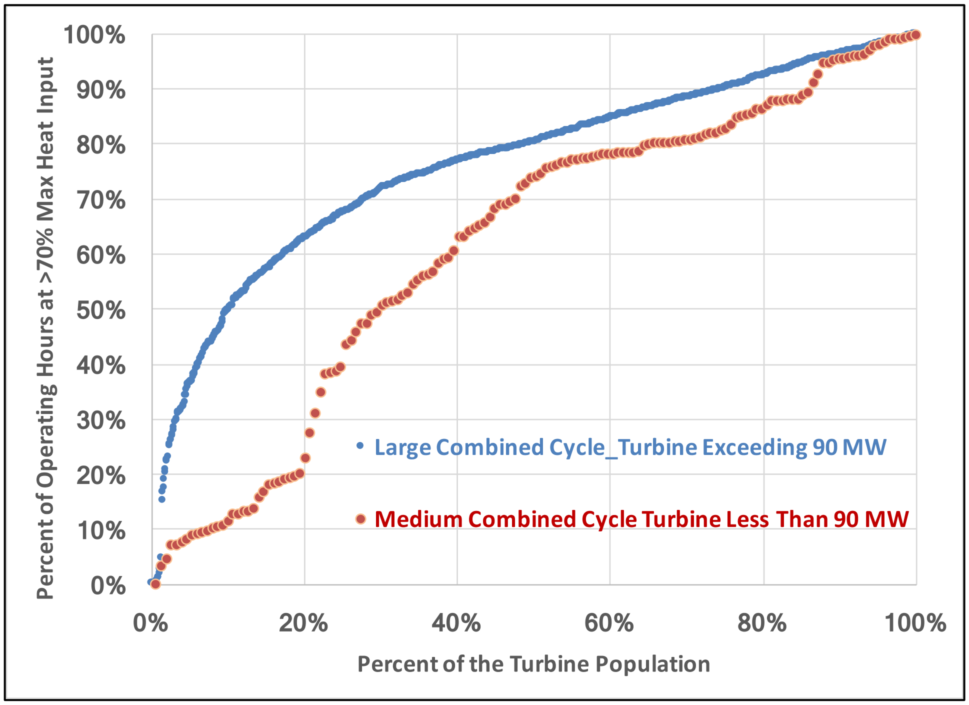

Figure 4-4. Operating Hours Exceeding 70% Load: Medium, Large Combined Cycle Units

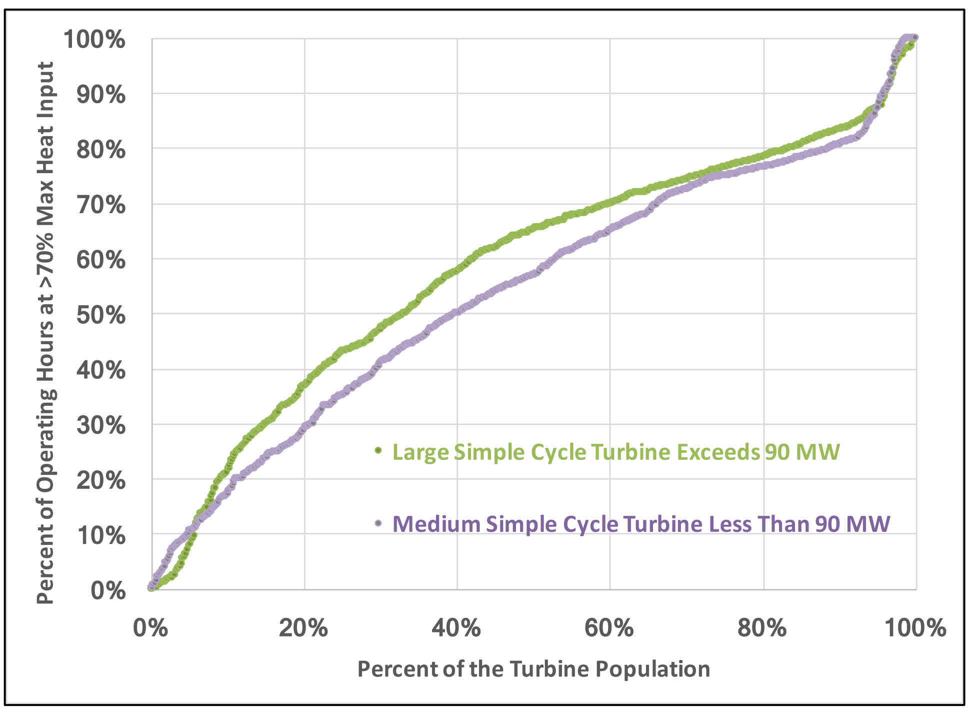

Figure 4-5. Operating Hours Exceeding 70% Load: Medium, Large Simple Cycle Units

Figures 4-4 presents the fraction of operating time (vertical axis) at high load for large and medium combined cycle units, as a function of the percent of turbine population. Figure 4-4 shows units at the mid-point of the population generally expend 80% of operating time at high load, demonstrating a preference for operating at conditions requiring SCR NOx controls.

Conversely stated, units at the population mid-point expend only 20% of their time at part load – the mode EPA is concerned would be popularized to avoid a strict NOx limit. Combined cycle turbines of the medium category exhibit a similar trend – units at the mid-point expend 75% of operating time at high load duty. Conversely stated, only 25% of operating time for these units is expended at part load. Any operations that are not consistent with the market's signal for power either compromises grid stability or requires non-economic operations.

Figures 4-5 presents analogous information for simple cycle units of the large and medium categories. Large simple cycle units at the population midpoint expend 66% of their operating time at high load, showing preference for conditions that require strict NOx control. Medium simple cycle units exhibit a similar trend, expending 57% of operating time at high load. In both cases the primary reason for increased operation at part load is the increased frequency of startup/shutdown cycles for these peaking units, and not extended operations at part load.

Limiting operation of these dispatchable resources risks the ability to manage peak demand and grid stability. Critical reliability services provided by simple cycle combustion turbines are rapid load ramping, and maintaining stable voltage and acceptable frequency response. Addressing these concerns, PJM's president, testifying to Congress on the need for dispatchable generation, noted the need to key role of existing sources to support reliability while non-dispatchable resources are introduced into the grid.[24]

The following conclusions are offered:

- Most simple cycle units operate at two modes – either idling or low part load (< 10%) of nameplate capacity, or high load as demanded by wholesale power market forces.

- The intentional operation of a unit at part-load duty to avoid requiring SCR incurs a cost penalty in terms of significant forgone revenue. Further, such an intentional limit restricts the capacity of these dispatchable resources, presenting risk to grid stability.

- Combustion turbine operation at part load is rarely intentional, and if necessitated will be to "balance" the grid to offset variable non-dispatchable asset generation.

[24] PJM Interconnection, Testimony of Manu Asthana President and CEO (Mar. 25, 2025), https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf

- Arbitrarily constraining operation at part load imposes major limits to asset duty:
    - Half of the medium and large combined cycle turbines (566) expend only 20-25% of their operating time at part load.
    - Similarly, half of the population of medium simple cycle turbines (505) expend almost half (43%) of their operating time at part load.
    - Half of the large simple cycle turbines (422) expend about 34% of their operating time at part load.

Such constraints would limit options to balance the distribution grid, and result in compromising reliability.

SECTION 5. ACHIEVABILITY: HIGH LOAD NOx LIMITS of 2, 3 ppm

The EPA, in considering NOx emission rates for high load duty, solicits comments on candidate NOx rates. Specifically, EPA state:

Based on current information, it does not appear that 2 ppm NOx is consistently achievable for highly efficient large combustion turbines. The EPA is soliciting comment on the ability of large frame simple cycle turbines using SCR to achieve the proposed emissions rate.[25]

This section presents comments on the feasibility of meeting a 2 ppm and a 3 ppm NOx limit. This report does not assess what an appropriate NOx limit would be.

In the rulemaking docket, EPA reports the results of an analysis evaluating the extent to which a given NOx emission rate can be successfully attained. [26] The referenced document (EPA-HQ-OAR-2024-0419-0020_attachment_1) reports the percentage of operating time over which 90 simple cycle and 75 combined cycle units achieve NOx emissions of 2, 4, and 5 ppm for averaging periods ranging from 4-hours to 30-days. EPA appears to judge the "achievability" of these rates by the fraction of operating time these units successfully meet any given rate. This "success rate" ranges from approximately 50% up to 100%, with most exceeding 90%.

This section reports an attempt to replicate EPA's results using the following methodology:

- Hourly emissions data for the year 2023 extracted from the Clean Air Markets Program Data (CAMPD) web portal

- Each operating hour is classified as high load or part load, by comparing reported heat throughput to the 70% of Reported High Load Rating (MMBtu/h) (Column H) to delineate between operating levels.

- The part-load emission rate limit is set at 0.37 lbs/MMBtu (96 ppm).

- High load NOx emission limits of 2, 3, and 4 ppm are utilized (corresponding to 0.0074, 0.01105, 0.0147 lbs/MMBtu), respectively.

- NOx emissions are calculated for 4-hour averages, when there are four hours of operation. NOx emission averages based on weighted heat throughput are calculated and rounded to the nearest .001, matching the reported accuracy of the hourly CEMS data.

[25] Fed. Reg. at 101336.

[26] *See* CT NOx List, available as attachment 1 in Docket ID No. EPA-HQ-2024-0419-0020.

- The 4-hour emission rate limits are calculated weighted by heat throughput, using 96 ppm for duty at less than 70% of maximum heat throughput, and either 2, 3, or 4 ppm at high load.

- The 4-hour emission rate averages for each unit are compared with the calculated 4-hour limits to assess theoretical compliance percentages.

Table 5-1 presents results of this analysis for six simple cycle and five combined cycle units.

Table 5-1. Probability of Meeting 2, 3, and 4-ppm NOx Limits: Comparison of Two Analyses

				Percentage of 4-Hour Average ER Meeting Standard					
				4 ppm (0.015 lbs/MBtu)		3 ppm (0.011 lbs/MBtu)		2 ppm (0.007 lbs/MBtu)	
		Average of 4Hr ER	Max of 4Hr _ER	EPA	This Study	EPA	This Study	EPA	This Study
Scattergood 7	Simple	0.008	0.027	99.9%	100.0%	99.3%	100.0%	91.7%	87.6%
Panoche 1	Simple	0.009	0.056	99.8%	99.6%	98.9%	97.7%	72.9%	91.4%
Montana 1	Simple	0.012	0.052	99.9%	99.9%	91.4%	97.6%	55.9%	37.2%
Desert Basin	Simple	0.019	0.168	89.7%	95.3%	86.7%	94.7%	67.8%	58.6%
Tejas 1	Simple	0.017	0.123	92.5%	95.4%	81.7%	55.4%	N/A	50.6%
Canal Station	Simple	0.022	0.026	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Dresden 1A	Combined	0.012	0.529	100.0%	99.9%	67.7%	44.1%	19.7%	8.8%
Riviera RBCT5A	Combined	0.009	0.158	100.0%	100.0%	100.0%	100.0%	99.9%	99.8%
Eagle Valley GT1	Combined	0.005	0.092	100.0%	100.0%	100.0%	100.0%	99.9%	100.0%
Jackson CT-02	Combined	0.006	0.058	100.0%	100.0%	100.0%	100.0%	100.0%	99.0%
Potomac CT-01	Combined	0.005	0.078	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

The results of calculations conducted in this study do not replicate EPA's results for all eleven example units. Results from this study project a lower frequency of compliance for three of eleven units for the 3 ppm limit, and six of eleven units for the 2 ppm limit. (For some units, this study projects a higher frequency of compliance rate than EPA). EPA, upon request, shared details of their methodology, revealing differences in treatment of substituted data, monitor downtime, and bias adjustment.[27] The project team considered these factors, as well as changes to other inputs in follow-up calculations, but results of the two analyses still could not be reconciled.

Results from both EPA and this study as reported in Table 5-1 show a 2 ppm limit is rarely met 100% of the time, even for combined-cycle units. For simple-cycle units, the percentage of time at which it is met is significantly lower. Only three of the 11 example cases are cited as successful for both EPA's and this analysis. The 3 ppm rate is achieved more often, as EPA

[27] Fellner, Christian, email personal communication to J. Cichanowicz et. al, *NOx Compliance Rate Methodology*, March 26, 2025.

projects 100% compliance for five of 11 units (most in combined-cycle duty), but the failure of six of the 11 units to meet 3 ppm suggests the compliance margin is small. Based on EPA's data and this analysis, there is no basis for a standard of 3 ppm, at least not for combustion turbines operating in simple-cycle mode.

In summary, the 2 ppm limit is too strict and not readily or consistently achievable. The 3 ppm limit can be met more frequently, but the compliance margin is small, suggesting challenges across the broad combustion turbine population, and especially for simple-cycle turbines. If EPA retains SCR as the technology requirement of the rule for some categories, it should adopt a standard higher than 3 ppm.

SECTION 6. SCR DESIGN AND OPERATION for PART LOAD

The EPA seeks comment on NOx controls for part load and for rapid changes in load, focusing on SCR design and operation. EPA solicits the following:

The EPA requests comment on the efficacy of combustion control technology operated in conjunction with SCR when units are in part-load operation.[28]

The EPA is soliciting comment on if it can be challenging to adjust ammonia injection rates during rapid load changes to maintain NOX emissions rates while at the same time minimizing ammonia slip….[29]

A response to these inquires is presented as follows.

SCR Process Design

The premise of SCR design is to provide uniform conditions of gas velocity, temperature, and composition entering the catalyst. Typically, the variance of gas velocity entering the catalyst should be maintained to +/- 10% per arithmetic average to maximize the usefulness of catalyst surface area. More important is the mixing of injected ammonia (NH_3) reagent and achieving a uniform ratio of NH_3/NOx. For combustion turbine applications requiring high (~75% or more) NOx removal, the NH_3/NOx ratio at the catalyst inlet should have a uniformity of 10%.

SCR reactors are designed to provide these conditions at high load and steady operation, but variances in load and the rate of change impose severe performance limits at part load. In one example, startup with a combustor pilot or diffusion flame presents a variability in NOx that can range from 10 ppm (near the combustor wall) to 70 ppm or higher. This variance must be eliminated by static mixers or other devices used to remedy imbalances in gas flow, temperature, and composition for SCR to be effective (assuming other difficulties are also resolved).

Gas Flow Mean Velocity, Distribution

Figures 6-1 presents sectional drawings of the transition duct for combined cycle SCR applications. Figure 6-1 shows ductwork expands by approximately a factor of three, from a nominal 20 x 20-foot cross section at the combustion turbine exit, to a 27 x 60-foot cross-section at the inlet of the first heat recovery steam generator (HRSG) tube bundle.

[28] Fed. Reg. at 101320.

[29] Fed. Reg. at 101325.

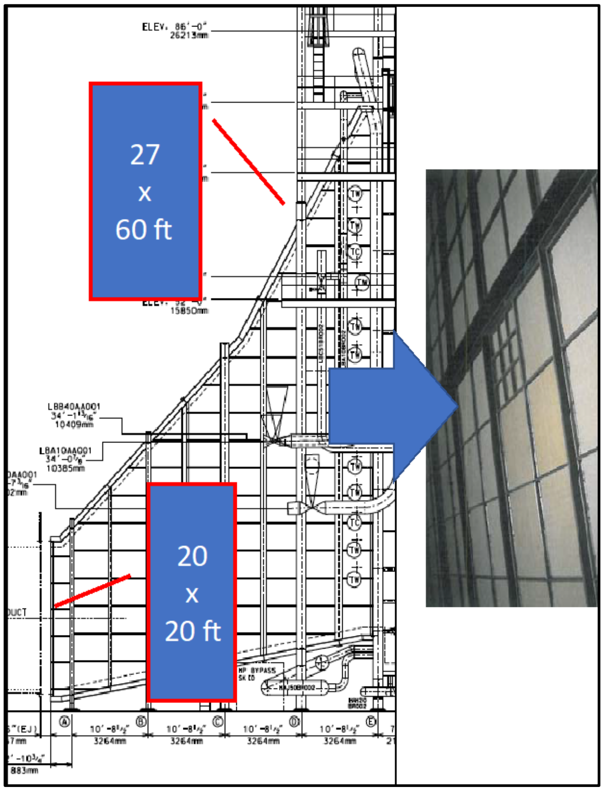

Figure 6-1. Ductwork Between Heat Recovery Steam Generator Inlet, First Tube Bundle

Ammonia Regent Mixing

More important than well-controlled and uniform gas mixing is a uniform NH_3/NOx ratio, ideally maintained to within 10% uniformity.

Figure 6-2 presents a typical NH_3/NOx distribution "fingerprint," characterizing the degree of uniformity of NH_3 and NOx across inlet ductwork of a simple cycle SCR reactor.[30] Figure 6-2 presents lines of constant NH_3/NOx ratio, with the value of "1.0" (or unity) reflecting the desired outcome of perfectly mixed NH_3 in the chemically correct stoichiometric proportion. The lines of constant NH_3/NOx stoichiometry less than unity reflect where NOx removal will be compromised; while those greater than unity reflect where residual NH_3 will be generated. The ideal NH3/NOx fingerprint features low density of lines, reflecting uniform NH_3/NOx ratio.

Part-load conditions, in particular less than 50%, challenge the task of achieving good mixing of NH_3 in the gas flow. The extent of mixing is defined by the momentum of NH_3, typically introduced within an air "jet" from the injection grid. The mixing of injected NH_3 is further enhanced by static mixers that impart turbulence to the gas flow. Static mixers are momentum-driven devices, thus lowering gas velocity to half or less than their value at full load compromises their effectiveness. Consequently, part load duty challenges achieving uniformity in process conditions and severely limits SCR performance.

[30] Martz, T.D. et. al., Gas Turbine SCR Performance Management: AIG Tuning and Catalyst Life Forecasting, Combined Cycle Journal, May 22, 2012.

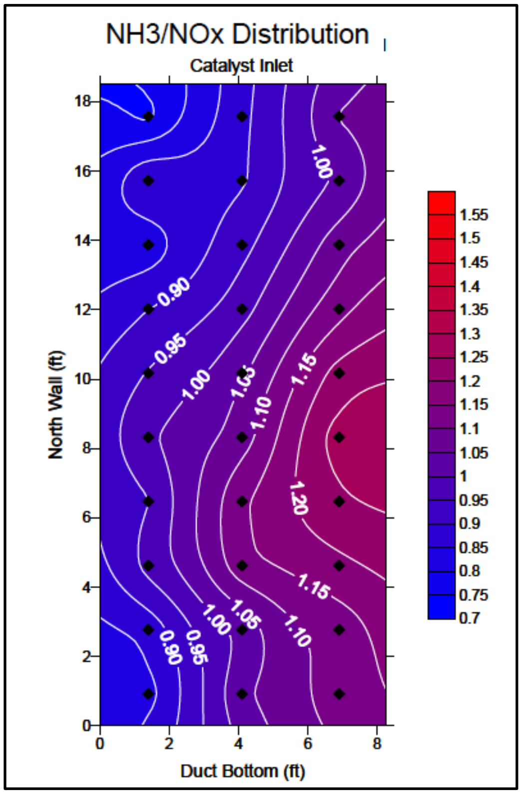

Figure 6-2. NH_3/NOx Distribution: Simple Cycle Application

Transient Conditions

Further complicating process design are rapid and frequent changes in conditions, such as transitioning from part load to high load within a short time period.

Unit Startup Rate

Figure 6-3 depicts the rate of change in load for a combined cycle unit under "hot-start" conditions, comparing the traditional design to "fast-start" units. Such "fast start" units, introduced into the turbine fleet over the last decade, enable a rapid increase in load. Figure 6-3 illustrates that the traditional hot-start mode can require up to 90 minutes to reach full load, as thick-wall tubes and turbine blades are heated at a prescribed rate to prevent thermal stress. Fast-start units are designed to do so in perhaps 30 minutes. These rapid load changes induce equally rapid changes in gas flow, temperature, and NOx content that impair SCR performance. Further complicating SCR performance is the "lag time" between the NH_3/NOx ratio introduced at the process inlet and that experienced at the catalyst surface. Since catalysts feature highly porous surfaces, injected NH_3 will penetrate the pores and be stored. This action introduces a time lag between NH_3 injected and that at the catalyst surface, which can compromise NH_3 (and lower NOx removal) for cases of load increase or generate excess NH_3 (and high breakthrough values) for load decreases.

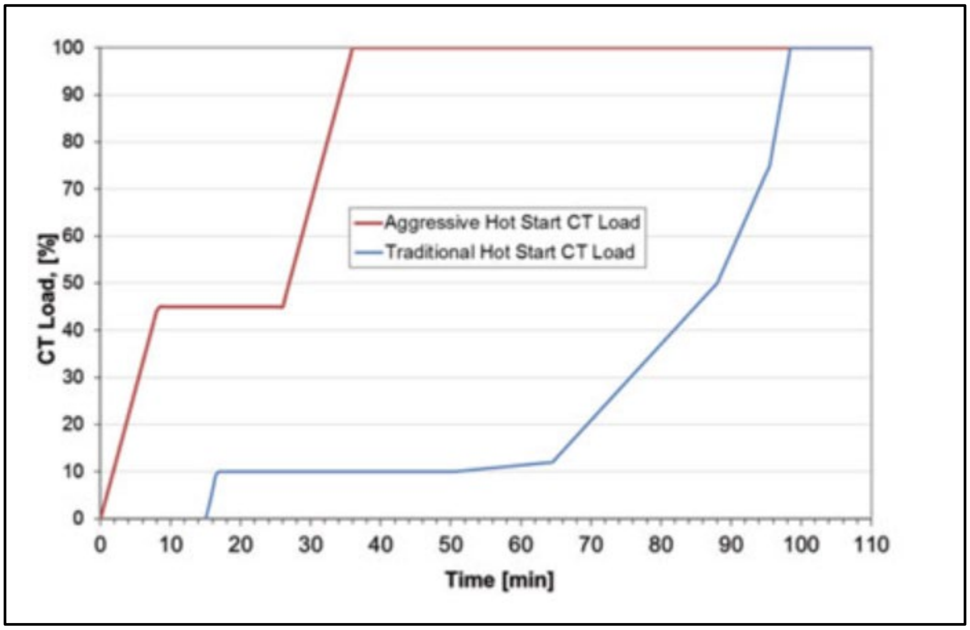

Figure 6-3. Combustion Turbine Load vs Time: Traditional vs. Fast Start Conditions

Transient Operation

Figure 6-4 presents startup data for a GE F-Series turbine. The data presented are (a) Load (yellow), (b) Gas Flow (blue), (c) NOx content (orange), and (d) SCR temperature. Figure 6-4 demonstrates, in the case of the turbine cited, highly variable NOx content, peaking at 70 ppm for a period of approximately 30 minutes, and SCR temperature that requires almost 3 hours to achieve the minimum for ammonia reagent injection (580ºF).

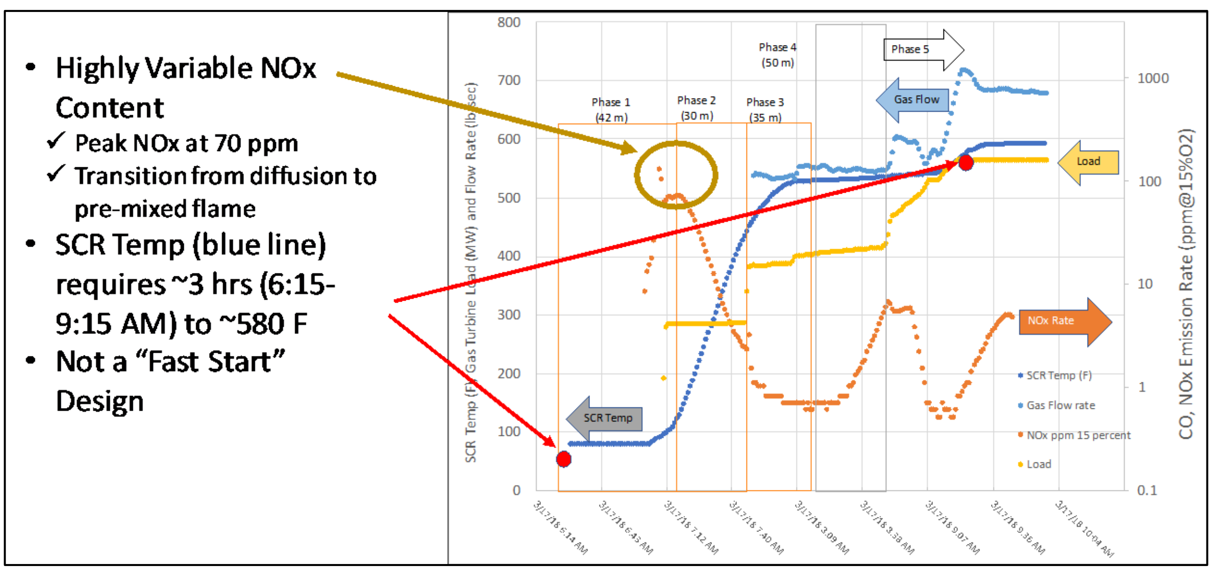

Figure 6-4. Startup Data: GE 7FA:1 x 1 Combined Cycle Arrangement

Consequently, several hours are required for SCR-driven NOx emission rates to be achieved. Although not a "fast–start" design, the description of process conditions in Figure 6-4 is representative for state-of-art generating units in a combined cycle.

A further depiction of highly variable conditions is presented in Figure 6-5. This figure shows the variability observed over 100 hours of rapid load changes. Most notable are variations in (a) gas temperature from 580 to 700ºF, within hours, (b) ammonia reagent injected, varying by a factor of 3 within hours, and (c) residual NH_3, which can approach 20 ppm.

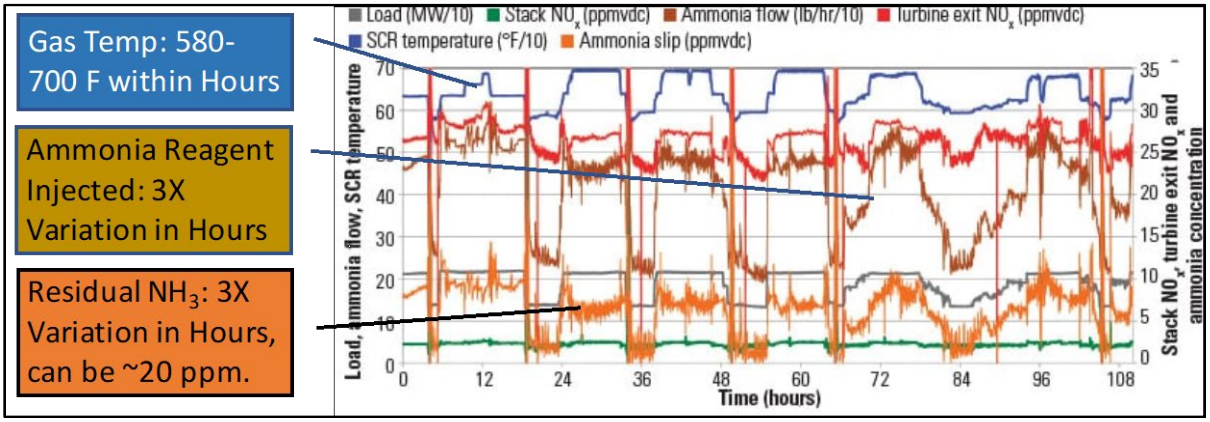

Figure 6-5. SCR Design and Operating Parameters: Highly Transient Conditions

The observation of residual NH_3 serves as a real-time indicator of imperfect conditions, a cumulative product of inadequate gas flow, temperature, and the NH_3/NO ratio.

These challenges to designing and operating SCR for low load and transient conditions are widely recognized, as noted in a recent publication:

> "When you operate advanced-technology machines at low loads, you tap out the capabilities of the design (Fig 6). The ammonia injection grid can't handle both the NOx levels at the maximum design output and what would be typical at 30-50% load, because of the corresponding changes in mass flow, temperature, and mixing."[31]

Concluding Observations

- Part load operation induces "spikes" in the process conditions that define SCR design – most notably NOx content, gas flow rate, and temperature. Abnormalities in these variables create conditions at an SCR reactor that increase the complexity of hardware design (such as for mixing), in most cases render the application of an SCR impractical.

- Part load conditions that compromise SCR design and operation are:

    - High NOx content observed at part load will vary widely during transitions between different burner operating modes.

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[31] *Consider the Impact of New Operating Regimes on your SCR*, Combined Cycle Journal. https://www.ccj-online.com/consider-the-impact-of-new-operating-regimes-on-your-scr/.

- A low gas temperature at less than 580ºF provides a minimal reaction rate for NOx removal.
- Low-velocity gas flow, as little as one-fourth of the design value, which impairs both the mixing of ammonia reagent in the gas stream and the penetration of the ammonia and NOx into the pores of the catalyst surface.

Section 7. CRITIQUE OF EPA's COST EVALUATION

Section 7 critiques EPA's cost evaluation for SCR NOx control, addressing both the capital cost for process equipment and the levelized cost per ton of NOx removed.

Three elements of critique are presented. First, the use of EPA's SCR cost-estimating procedure, as presented in the rulemaking docket, is reviewed and applied to alternative conditions that better reflect the classes of turbines and load ranges in the duty-based subcategories. Second, the combustion turbine NOx emission rate assigned is adjusted to consider the disparate rates from aeroderivative and three different frame designs. Third, EPA's development of SCR capital cost – primarily for simple cycle units – is reviewed and augmented with inputs from recent projects. Fourth, the challenges to retrofit SCR for existing units are described, and cost estimates offered.

Review and Revision of EPA's Procedure

The EPA developed a cost-estimating procedure for SCR to calculate the cost per ton of NOx removed based on inputs such as capital cost, unit capacity factor, and the initial and controlled NOx emissions. This methodology in the rulemaking docket[32] employs SCR capital cost as derived for the NETL[33] by Black & Veatch (B&V). The methodology assumes a unit capacity (as heat throughput), capacity factor, NOx at the combustor exit, and the desired NOx emissions rate. EPA uses these inputs with the methodology to calculate the cost per ton of NOx removed.

The EPA also cites two values of SCR capital cost in the Proposed Rule.[34] Table 7-1 summarizes the SCR costs cited and those reported in the NETL reference.

The costs in Table 7-1, reportedly derived from B&V's experience in designing and operating SCR processes on combustion turbines, are relatively consistent when adjusting for generating capacity (using the "2/3" scaling relationship). Table 7-1 costs are also consistent with the SCR capital requirement cited by the NETL 2023 Cost Study when the role of combustion turbine capacity is defined.

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[32] See NETL Detailed Costs SCR Nov 2024 available in Docket ID No. EPA-HQ-2024-0419-0017.

[33] NETL 2023 Cost Study.

[34] 89 Fed. Reg. at 101326, footnote 37.

Table 7-1. SCR Capital cost Per EPA

Reference	Combined Cycle	Simple Cycle
NETL	\$6.3 M for 717 MW (~\$9/kW)	\$5.7M for ~105 MW with attemperation: \$25/kW without attemperation: \$47/kW
Fed Reg. at footnote 37	~\$10/kW for 400 MW	\$70/kW for 50 MW
Fed Reg. at 101326	\$4-10M for "large" units • \$4 M per 100 MW = \$40/kW • \$10 M for 1,000 MW = \$10/kW	\$2-4 M for Small/Medium CT (~\$40-80/kW)

The capital recovery and fixed and variable operating costs are consistent with conventional practice. The fixed operating and maintenance (O&M) cost, expressed as a percentage of capital, is 3%. The variable O&M is calculated based on reagent and heat rate penalties. The NETL/B&V assumption of an auxiliary load of 0.3% gross, a unit lifetime of 15 years, and a 7% cost of funds is consistent with standard practice.

The EPA's assumed reference generating unit and capacity factor to estimate the levelized cost per ton of NOx for simple cycle and combined cycle units, however, bias control cost to values lower than likely to be observed in commercial practice.

Turbine Frame Classes

A significant shortcoming is EPA's failure to recognize the differences in NOx emissions from various turbine "frame" and aeroderivative designs. Differences in turbine and combustor design result in a range in NOx emissions, ranging from 25 to 5 ppm.

Figure 7-1 depicts the evolution of different combustion turbine frame classes over time.[35] Figure 7-1 highlights the increase in combustion turbine efficiency when operating in combined cycle, and portrays on the horizontal axis the changes in design and materials with the E-Class, F-Class, and H-Class turbines. The use of advanced materials of construction, advanced combustor design, and improved cooling technology enable the use of higher combustor firing temperature, ranging from approximately 1,200ºC for E-Class to as high as 1,600ºC for the H-Class. The evolution to higher firing temperatures – and the implications for NOx – should be considered in EPA's cost evaluation to achieve an SCR-driven NOx rate (e.g. 3 or 4 ppm at 15% O_2).

[35] A Brief History of GE Gas Turbines, Power Magazine, July 8, 2019. Powerhttps://www.powermag.com/a-brief-history-of-ge-gas-turbines-2/.

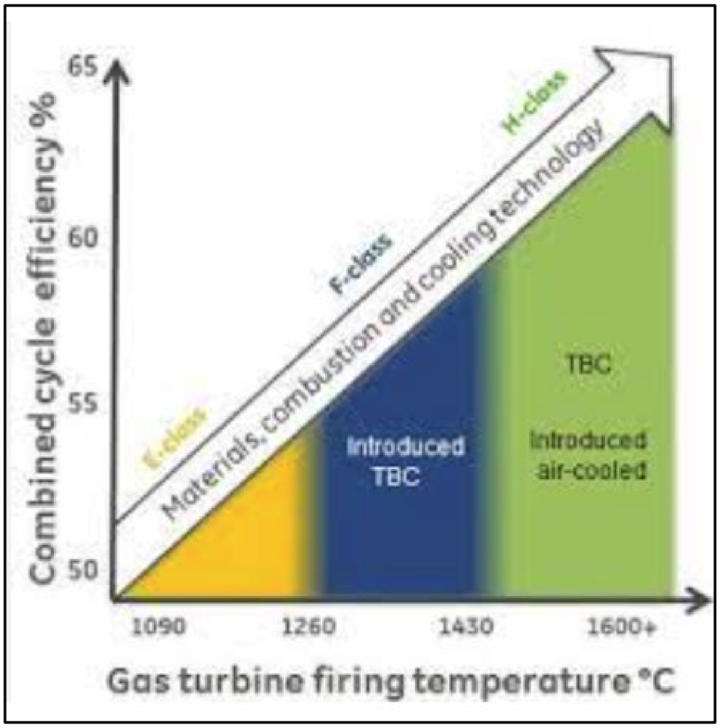

Figure 7-1. Evolution of E, F, and H-Class Frame Engines

The disparity in NOx emission is evident in both the comments submitted by EPRI[36] to this rulemaking and EPA's summary of combustion turbine performance, developed as part of this rulemaking.[37] Both sources show, almost without exception, aeroderivative turbines typically emit 25 ppm. The differences are notable for frame combustion turbines. Using GE designations as an example:

- Larger H or HA frame units (commonly referred to as H-Class) also consistently emit 25 ppm, using DLN.
- F-Class turbines can consistently emit 15 ppm, with some units achieving 9 ppm, depending on the combustor type.
- E-Class turbines engines – depending on the combustor type – generate NOx from as high as 25 and 15 ppm; with some emitting as low as 5 ppm.

A similar pattern is evident in combustion turbines from other suppliers.

[36] Comments of the Electric Power Research Institute on Environmental Protection Agency EPA-HG-OAR-2014-0128; FRL-5788-02-OAR, Review of New Source Performance standards (NSS) for Stationary Combustion Turbines and Stationary Gas Turbines - Proposed Rule, March 13, 2025.
[37] EPA-HQ-OAR-2024-0419-=0020_attachment_3.

Reference Unit Selection

There are three flaws in EPA's calculation of results using a generic reference unit. These are (a) generating capacity, (b) selection of capacity factor, and (c) failure to recognize the disparate NOx emissions from various combustion turbine "frame" designs. The assumptions for the cost evaluation are revised and updated as follows.

First, EPA selects a reference unit size that minimizes the cost of SCR per unit of generating capacity. Specifically, EPA selects the largest gas turbine available on the market – 4,450 MMBtu/h. Figure 7-2 shows this combustion turbine's heat throughput and capacity at the 99.7th percentile of the population. Indeed, such a large turbine corresponds to the largest H-Class turbines available on the market and likely not representative of the current H-Class turbine population. However, a capacity exceeding 82% of the present inventory, as opposed to 99.7% as projected by EPA, seems more likely. The revised reference case assumes a combustion turbine capacity of 1,780-2,130 MMBtu/h, as exhibited in Figure 7-2, and is adopted for this study.

In addition to altering the reference unit, this study evaluated several classes of frame turbines. Specifically, three reference cases instead of one are evaluated to reflect the substantially different emissions rates from turbines equipped with advanced combustors. Three classes of frame turbines are addressed: (1) H-Class—380 MW, corresponding to 3,420 MMBtu/hr, with a combustion-controls NOx emissions rate of 25 ppm; (2) F-Class—200 MW, corresponding to 1,800 MMBtu/hr, with a combustion-controls NOx emissions rate of 9 ppm; (3) E-Class—88 MW, corresponding to 850 MMBtu/hr, with a combustion-control NOx emissions rate of 5 ppm.

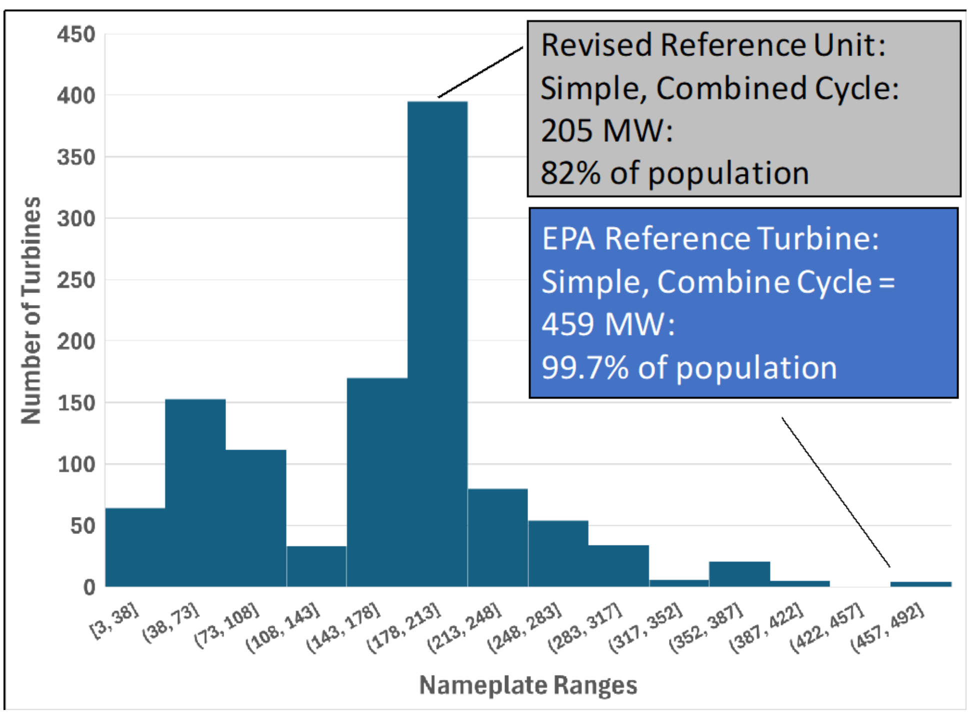

Figure 7-2. Combustion Turbines Population vs Nameplate Capacity

A reference unit of this generating capacity incurs a SCR capital cost determined using EPA's calculation procedure submitted to the rulemaking docket.[38] This procedure for a given heat throughput defines the SCR capital cost and assigns operating cost based in the inlet and outlet NOx emissions. The levelized cost per ton of NOx removed is calculated based on capacity factor. For the revised reference unit of approximately 2,000 MMBtu/h, the normalized cost for SCR is determined as $28/kW for simple cycle and $12/kW for combined cycle, compared to $15/kW for simple and $9/kW for combined cycle for EPA's 4,900 MMBtu/h reference unit.

EPA selected capacity factors for two of the three categories that do not reflect the potential maximum cost. Table 7-2 compares the capacity factor for three categories of operation and the associated turbine cycle considered by EPA: *Low* (Simple Cycle), *Intermediate* (Simple Cycle), and *Base* (Combined Cycle). Capacity factors selected for the purpose of identifying the highest cost per ton should reflect the lowest capacity factor of each category. EPA's selection of capacity factor for the *Low* category of 5% is reasonable (since zero is not realistic). However, the basis for the *Intermediate* category should be corrected from 30% to 20% (the lower end of the Intermediate category range), and for the *Base* category from 60% to 40% (the lower end of the *Base* category range).

Table 7-2. Comparison of Capacity Factors for EPA and Revised Basis

CATEGORY	CYCLE	EPA CAPACITY FACTOR	REVISED CAPACITY FACTOR
Low (<20%)	Simple	5	5
Intermediate (20-40%)	Simple	30	20
Base (>40%)	Combined	60	40

EPA uses NOx emission rates in the calculation that do not reflect the disparity of the four categories of combustion turbines described (aeroderivative, and E- F-, and H-Class turbines).

Cost Evaluation: EPA SCR Cost

A cost evaluation is presented that first replicates EPA's analysis, using EPA's SCR costs but a more realistic generating capacity and capacity factors, as described above, and further evaluates how control cost can vary by combustion turbine frame design.

Table 7-3 summarizes these revised results, showing the levelized cost per ton of NOx removed per turbine class, addressing four scenarios of NOx reduction, for the relevant SCR capital cost and capacity factor.[39] Specifically, the NOx reduction scenarios considered (Column B) are: (a) 25 to 3 ppm (H-class and aeroderivative); (b) 15 to 3 ppm (some F-Class), (c) 9 to 3 ppm (advanced DLN F-Class), and (c) 5 to 3 ppm (Advanced DLN E-Class). For each of these

[38] EPA-HQ-OAR-2024-0419—0017_attachment_1.

[39] The referenced calculation is conducted with the referenced EPA procedure, using the change in NOx emissions and capacity factors as specified.

scenarios, the cost is presented for four cases: Low load (simple cycle), Intermediate load (simple cycle), and Base load (combined cycle). Table 7-3 reports SCR capital cost (Column D) based on EPA's methodology and the capacity factor (Column E) selected for analysis.

Table 7-3. Summary of Revised Cost Evaluation

Column A Fed Reg: 101334	Turbine Class	Column B NOx Δ ppm	Column C GT Design	Column D SCR $/kW	Column E Capacity Factor	Column F $/ton EPA-HQ-OAR-2024-0419-0017 _attachment_1	Column G $/ton (@ 2,000 MBtu/h)
Low (<20%)	H	25 to 3	SC	28	5	18,391	25,011
Intermediate (20-40%)			SC	28	20	4,894	7,899
Base >40%)			CC	12	40	3,545	5,047
Low (<20%)	F	15 to 3	SC	28	5	33,000	45,256
Intermediate (20-40%)			SC	28	20	8,400	13,884
Base >40%)			CC	12	40	3,800	5,732
Low (<20%)	F	9 to 3	SC	28	5	65,000	89,361
Intermediate (20-40%)			SC	28	20	16,000	26,618
Base >40%)			CC	12	40	6,400	10,314
Low (<20%)	E	5 to 3	SC	28	5	190,000	261,761
Intermediate (20-40%)			SC	28	20	42,000	75,553
Base >40%			CC	12	40	16,000	27,272

The cost as determined using EPA's methodology and inputs (Column F) is compared to results (Column G) based on lower heat throughput and associated higher SCR capital (Column D), and capacity factor (Column G). The revised results show higher cost incurred by a factor of 1.5 to 2.

Cost Evaluation: Updated Capital Cost for SCR

The estimates of capital cost used by the EPA – although developed by an experienced engineering firm – do not reflect recent market conditions. The NETL concedes these costs may not reflect evolving market conditions, with the following disclosure:

The results......in this study are not intended to reflect a specific operational model or all the potential market pressures experienced by plants operating today, or the price consumers can expect to pay.[40]

[40] NETL 2023 Cost Study at 4.

Recent experience by combustion turbine owners confirms this observation. Table 7-4 presents a summary of SCR cost estimates acquired by owners for both simple and combined cycle duty. These costs significantly exceed those projected by the NETL.[41]

New Unit

Table 7-4 reports SCR capital cost for new simple cycle units significantly exceed the cost utilized by EPA. Levelized cost per ton of NOx removed is either from a cited reference or calculated using EPA's procedure.

EPA reports but unexplainably dismisses the significant SCR costs for Jack County, estimated on a normalized basis as $25.1/kW, resulting in a cost per ton exceeding $67,000 (even at 29% capacity factor, which is not the low end of the intermediate category range). Further, SCR capital costs solicited by owners for simple cycle units readily exceed EPA's references. The capital for SCR for the 229 MW TVA Colbert unit (and F-Class turbine with a guaranteed advanced DLN rate of 9 ppm) is estimated as $94/kW, which for a capacity factor of 20% translates to almost $50,000 per ton. Equipping the 88 MW TVA Paradise units (E-Class turbines with a guaranteed rate of 5 ppm) with SCR requires almost $300/kW, translating into more than $550,000 per ton for the negligible reduction in NOx (from 5 to 3 ppm) at 20% capacity factor.

SCR estimates for the largest combustion turbines operating in simple cycle also show capital and levelized cost per ton exceeding EPA estimates. Georgia Power's Yates Units 8-10 each are projected to require between $66 and $108/kW for SCR procurement and installation. Levelized cost per ton varies with NOx removed and approaches $20,000 for reductions from 25 to 3 ppm.

Table 7-4. Cost Summary: New Unit SCR Capital Costs

Owner/ Station	**Gas Turbine Capacity (MW), Supplier**	**Capital Cost ($M)**	**Capital Cost $/kW**	**Capacity Factor (%)**	**$/ton (per NOx reduction)**
Jack County[42]	490 (not specified)	32.15	25.1	29	15 -5 ppm: 67,088
TVA Colbert	3 x 229 (GE 7F.05)	65	94.1	20	9-3 ppm: 48,635
TVA Paradise	88 (GE 7E.03)	26.3	298	20	5-3 ppm: 551,000
GA Power Yates 8-10	453 Mitsubishi 501JC	30-47	66-108	20	25-3 ppm: 13,337-19,275

[41] Ibid.

[42] EPA-HQ—OAR-2024-0419-0020_attachment_1. See worksheet "Permit Detailed Costs."

Retrofit

Retrofitting SCR into either a simple or combined cycle unit presents challenges in creating the necessary space to provide the process conditions described in Section 6. For this reason, the retrofit of SCR is an unrealistic option for existing units, and would be much costlier (on a $/kW basis) than for new combustion turbines.

Simple Cycle

Figure 7-3 is a satellite image of a typical F-Class simple cycle combustion turbine equipped with SCR, demonstrating the space required and relative location of the SCR. Simple cycle units not initially configured for SCR usually do not have adequate "footprint" for ductwork, as the turbine exit is typically close-coupled to the stack to minimize ductwork and gas pressure drop.

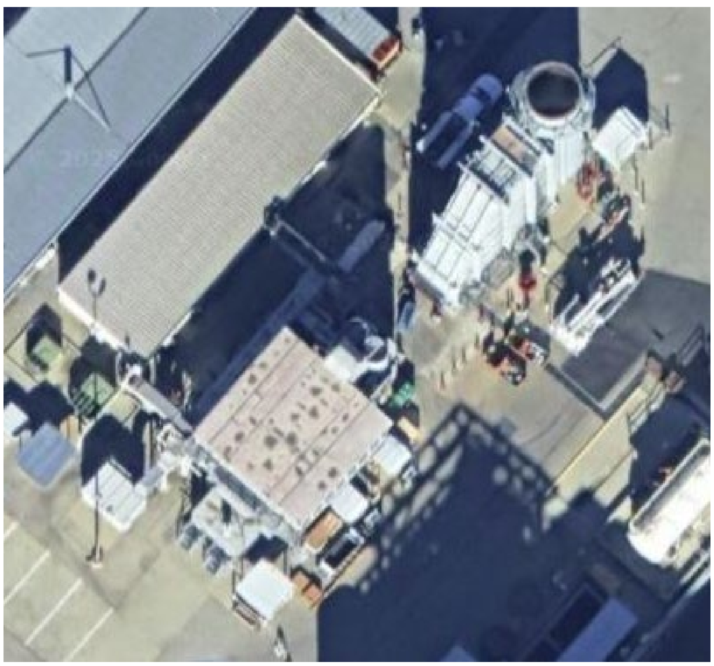

Figure 7-3. Salt River Project Ocotillo Simple Cycle Unit Equipped with SCR

The retrofit of such process equipment will require either relocating the stack or configuring the SCR reactor in a parallel duct or "sidecar" concept. Either of these adds gas pressure drop and create a tortuous path for gas flow, making it difficult to achieve a uniform gas flow distribution at the catalyst inlet. To achieve high NOx removal relocating the stack and maintaining a simple gas flow are needed. The associated costs make this unrealistic.

Table 7-5 summarizes retrofit SCR cost reported by two owners, and levelized cost per ton (calculated using EPA's procedure). One Midwestern owner of 450-500 MW combustion turbines engaged a third-party engineering firm to evaluate retrofit design and cost for two units. The equipment suppliers' bid and installation cost equate to $35-55 million for a complete "turnkey" installation a single unit, representing a normalized capita cost of $76-120/kW. Based on a capacity factor of 20%, an assumed H-Class design, and the 25-ppm combustor NOx, the levelized cost per NOx ton removed can exceed $20,000 (for reduction to 3 ppm).

Table 7-5. Retrofit SCR Cost Evaluation: Simple Cycle Units

Owner/ Station	Gas Turbine Capacity (MW), or Supplier/Frame	Capital Cost ($M)	Capital Cost $/kW	Capacity Factor (%)	$/ton (per NOx reduction)
Midwestern Owner	450-500	35-55	76-120	20	25-3 ppm: 15,112-22,051
Consumers Energy Company (Zeeland)	GE 7 FA	66.8	322	20	9-3 ppm: 201,830

Similarly, an engineering study for Consumers Energy Zeeland Station addressed the design and cost to retrofit SCR to a GE-7 FA Frame unit.[43] The projected capital charge equates to $322/kW, with the publicly reported cost per ton as $40,366 per ton for a 100% capacity factor[44] (implying approximately $200,000 per ton for 20% capacity factor).

Combined Cycle

Retrofitting an SCR into a combined cycle unit similarly requires providing for adequate space for catalyst installation and well-controlled process conditions.

Figure 7-4 presents a schematic view of a heat recovery steam generator configured for SCR. This figure shows approximately 13 feet of process equipment is needed.

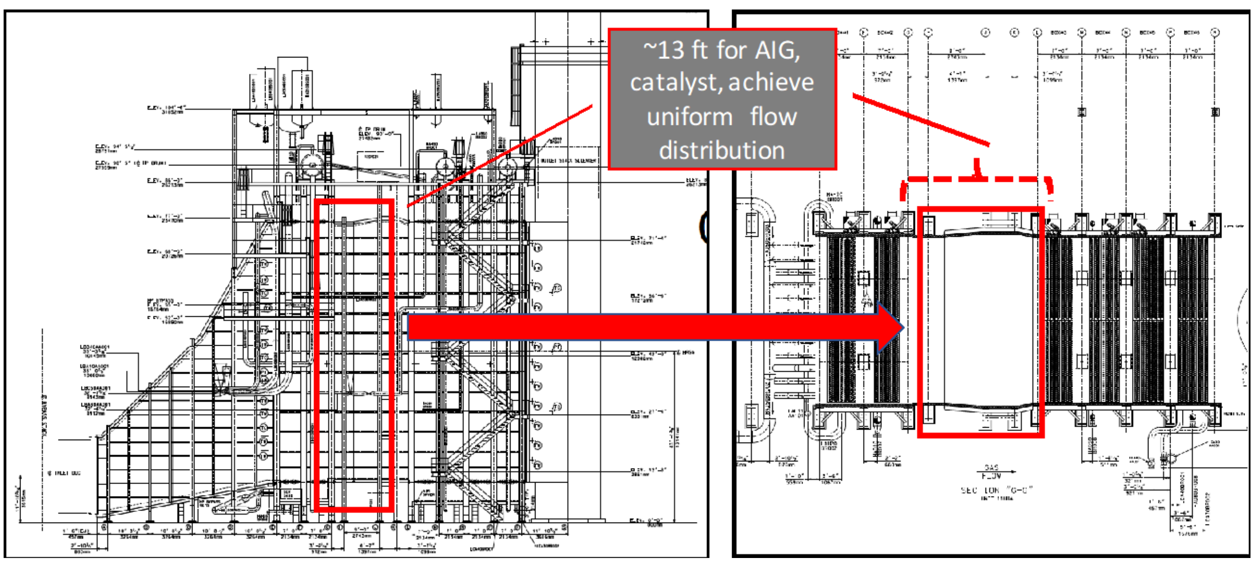

Figure 7-4. Sectional Drawing: HRSG Design to Accommodate SCR

[43] *Technical Support Document Permit to Install Application Covering a Proposed Modification of the Zeeland Generating Station*, Prepared for Consumers Energy Company, April, 2024.

[44] Ibid. Appendix C at 108.

Most notably, the spacing between the first and second tube bundles is defined as the only option to locate the necessary SCR process conditions.

Figure 7-5 presents an engineering sectional view of the HRSG for the existing Jackson Generating Station[45] in Michigan. Two means were explored to retrofit SCR. First, the conventional approach of modifying the HRSG to accommodate SCR process equipment was evaluated. The SCR process design identified 11.5 feet as required, which is not feasible as the existing arrangement provides approximately 3 feet. Removing steam tubes could expand the footprint to 11 feet, but this would reduce the output and thermal efficiency of generation.

The second approach considered was to uniquely attempt to retrofit an SCR catalyst into the HRSG's expansion ductwork. This action—never attempted commercially—was abandoned due to the inability to rectify the highly turbulent gas flow into a well-behaved uniform flow pattern and inject reagent to achieve the desired mixing uniformity.

Costs were not developed for either approach as the technical feasibility was judged inadequate for a commercial venture.

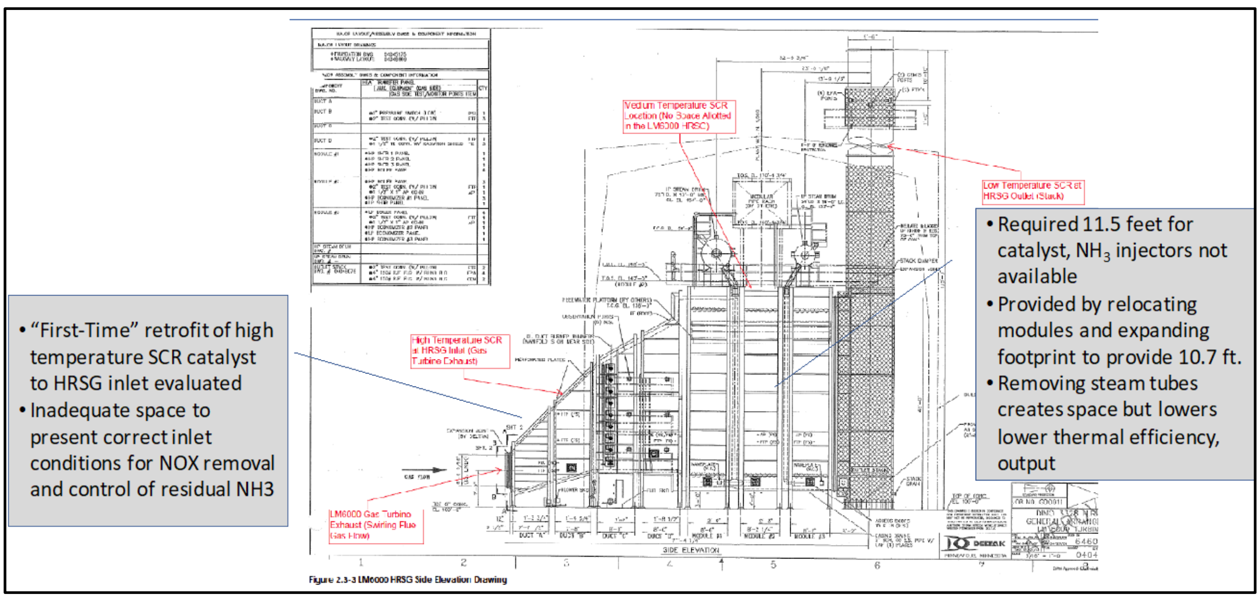

Figure 7-5. Jackson Unit: Options to Retrofit SCR

Observations are summarized as follows:

- EPA's selection of reference units is flawed. EPA selected the generic reference unit at almost the largest capacity available, biasing SCR cost per unit capacity low. EPA also selected capacity factors for two of the three categories of operation that do not reflect the

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[45] *Technical Support Document: Permit to Install Application Covering a Proposed Modification of the Jackson Generating Station*, Jackson County, Michigan. Prepared for Consumers Power, June 2018.

highest cost. Further, the reference unit does not reflect the widely divergent NOx emissions of the four different classes of turbines.

- These shortcomings are addressed by replicating EPA's calculations using a more realistic capacity of 2,000 MMBtu, lower capacity factors that reflect the low end of the range of each duty-based subcategory (per Table 6-1), and conducting the cost per tom calculations for a range of combustor exit NOx emissions. Revised results show EPA underpredicting the cost per ton for NOx removed by 50 to 100%.

- A more notable shortcoming is EPA ignoring the divergent NOx emissions from the turbine categories of aeroderivative, E-Class F-Class, and H-Class. Updating EPA's calculations for simple cycle duty and considering NOx emissions ranging from 25 ppm to as low as 9 and 5 ppm show estimated cost ranges from $25,000 to exceeding $200,000 per ton of NOx.

- EPA's estimates of SCR capital cost for new combustion turbines are dated and not relevant in the present market. Recent estimates of SCR capital show significantly higher cost. The normalized cost ($/kW) estimates for combustion turbines of 229-450 MW (F-Class and H-Class frame turbines) range from $66 to more than $100/kW; one case for an 88 MW unit (E-Class frame turbines) projected cost approaching $300/kW. This elevated capital cost, combined with lower combustor NOx emission rates, elevates the levelized cost per ton that (with the exception of a 25-ppm combustor rate) ranges from $50,000 per ton to over $500,000 per ton.

- The space required for an SCR reactor within the footprint of an existing simple cycle unit is not available without major changes to the unit. Cost estimates to retrofit SCR to existing units are similarly elevated; for two examples, capital costs ranged from approximately $100/kW to $300/kW. Depending on the combustion NOx rate and capacity factor, the levelized cost per ton is more than $20,000 and can exceed several hundreds of thousand dollars.

- The retrofit of SCR to an existing combined cycle unit HRSG that is not designed to accommodate the necessary process conditions is not technically feasible. The space required to (a) correct gas maldistribution from the gas turbine exit, (b) inject NH_3 and mix with gas to high uniformity, and (c) lower gas velocity to ~15-20 actual ft/sec for to achieve proper residence time and minimize pressure drop is not available without significant modification to the HRSG.

SECTION 8. UPGRADES AFFECTING HOURLY EMISSIONS RATE

The EPA in addressing potential modification to combustion turbines states:

If an owner/operator replaces a combustor with another version with the same ratings as the previous combustor, such that the emission rate to the atmosphere of NOx or SO2 is not increased, the combustion turbine would not trigger the NSPS modification criteria. The EPA is soliciting comment on whether there are other actions that could increase the potential hourly emissions rate of a combustion turbine and thus may constitute ''modifications'' and whether any unique considerations exist for this subcategory.….

EPA rightly recognizes the environmental benefits of upgrading a combustor. Almost without exception, NOx emissions decrease subsequent such an upgrade; the dry low NOx combustor designs employ advanced means of mixing fuel and air to control flame temperature. A combustor upgrade, as part of changes associated with a "hot gas path upgrade" can also increase the thermal efficiency of power generation. These benefits serve to justify not considering this change as a basis to trigger NSPS.

EPA solicits input on other actions that could potentially increase hourly output. Two actions can each increase air flow to exploit the upgrade to the hot gas path and not contribute to an increase in emissions. Specifically, both a compressor upgrade[46] and retrofit of high flow inner guide vanes[47] can increase the air flow. If contemporaneously retrofit with a combustor upgrade these are still aspects of upgrades that contribute to lower NOx emissions. Further, emissions of SO_2 may not necessarily increase, depending on the increase in combustion turbine thermal efficiency.

In summary, actions to increase combustion turbine airflow will not necessarily increase NOx and SO_2 emission, and trigger NSPS, when deployed with a combustor upgrade.

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[46] . https://www.psm.com/retrofits-and-upgrades/gas-turbine-optimization-package-and-combustion-upgrade-packages.

[47] Phillips, J. et. al., Gas Turbine Performance Upgrade Options. Available at https://static1.squarespace.com/static/5b08345b1aef1d82050969af/t/5b1abfb70e2e7242ed7ce0f3/1528479672115/gt_upgrade_options.pdf.

Attachment B

AGORA ENVIRONMENTAL CONSULTING

MEMORANDUM

TO: **Power Generators Air Coalition (PGen)**

FROM: **Steve Norfleet, Agora**
Mike O'Connell, Agora

DATE: **April 14, 2025**

Re: **Comments on the Proposed "Review of New Source Performance Standards for Stationary Combustion Turbines and Stationary Gas Turbines" Revisions to Subparts KKKKa, KKKK, and GG of 40 CFR Part 60 (Docket # EPA–HQ–OAR–2024–0419)**

Agora Environmental Consulting (Agora) provides these comments on behalf of the Power Generators Air Coalition (PGen), on the proposed revisions to the New Source Performance Standards (NSPS) for stationary combustion turbines that were published in the Federal Register on December 13, 2024.[1] As requested, Agora's review focused on the monitoring and reporting requirements as well as related ambiguities in the proposed regulatory text, and we do not purport to address all the concerns that Agora or that the members of the Power Generators Air Coalition may have regarding the proposed revisions.

Recommend Revising §60.4320a(b)(3) to Apply the Natural Gas Emission Standard during Hours when Only Natural Gas Is Combusted

Liquid fuels (and other more variable gaseous fuels) are typically combusted using diffusion flame burners, where fuel and air are injected into the combustor and mixed only by diffusion, which creates a high-temperature primary combustion zone and the potential for high thermal NO_X formation. Given this and other effects that may impact the emissions during periods when a unit is transitioned from one fuel to another, it could be difficult for a source to meet the more stringent emission standard for natural gas combustion when another fuel is also being combusted, even if the other fuel represents less than 50% of the total heat input during the hour. A more reasonable approach would be to apply the applicable NO_X emission standard for natural gas during hours when the stationary combustion turbine fires only natural gas and to apply the highest applicable NO_X emissions standard for an hour if multiple fuels are combusted during that hour.

[1] 98 Federal Register 101306 (December 13, 2024)

Recommend Revising the Emissions Limits for a Group of Combustion Turbines Sharing a HRSG (i.e., a Combined-Cycle Affected Facility) to Be Prorated Based on the Configuration of the Unit to Reflect What the Affected Facility Can Reasonably Achieve

The proposed language in §60.4333a(e)(2) addresses configurations where "two or more combustion turbines are exhausted through a single steam recovery unit" and discusses how the source must measure the total emissions at the exhaust stack and the fuel flow (for purposes of determining the percentage of the base load rating) from each of the combustion turbines and duct burners associated with that configuration. However, the provision states that "the applicable emission standard for the affected facility is equal to the most stringent emissions standard for any individual unit." Similar language is found in 60.4333a(f), which addresses such configurations that elect to comply with the output-based standard.

However, instead of applying the most stringent standard in each case, the provision should allow sources to prorate the standard based on the respective heat input to each turbine in the configuration. While you could <u>allow</u> sources the option of complying with the most stringent standard, prorating the emission standard for the units operating in a combined configuration would appropriately address situations where it is not reasonable to apply the same standard to different types of units or units at different stages of operation. For example, a combined cycle unit operating above certain capacity factors may be required to control NOx emissions using an SCR. But if one combustion turbine sharing a common heat recovery steam generator (HRSG) is burning a different fuel or one of the combustion turbines sharing the HRSG is in transition and has not yet achieved lean pre-mixed combustion while the other combustion turbine(s) are at normal load, it would not be reasonable to expect the more stringent emission limit to be met even though all the units in the configuration may be operated and controlled properly given the circumstances. Another configuration that is similarly problematic is one where the standards for the two turbines sharing a common HRSG are different (e.g., they are based on advanced combustion controls, not SCR). For example, PGen's comments suggest that the data support a 5 ppm NO_X standard for E-Class turbines and a 9 ppm standard for F-Class turbines. If EPA adopts these two standards, an E-Class turbine and an F-Class turbine sharing a common HRSG would have a standard of 5 ppm and 9 ppm, respectively (without requiring an SCR); in that case, it would also not be reasonable to expect the 9 ppm turbine to meet the other's, lower, 5 ppm standard. By prorating the combined hourly emission standard using heat input or output, similar to the way the emission standard is prorated for a unit (or configuration of units) for each hour within the 4-operating hour or 30-operating day period using Equations 5 and 6 in the proposed rule, the emission standard can appropriately reflect the emissions that can be reasonably achieved by the group of turbines in the configuration for any given hour.

Allow the Use of Part 75 NO_X Monitoring Provisions for All Units without Requiring Approval

As proposed, §60.4345a(b) states that the "Administrator or delegated authority may approve" the use of CEMS certified in accordance with Appendix A of Part 75 in lieu of the Part 60 procedures on “stationary combustion turbines that do not use post-combustion technology to reduce emissions of NO_X” provided that the RATA is performed on a lb/MMBtu basis. Likewise, §60.4345a(f) states that a QA program following Appendix B to Part 75 may be used, again “with approval of the Administrator or delegated authority, in lieu of the Part 60 requirements on a “stationary combustion turbine that does not use post-combustion technology to reduce emissions of NO_X” for Subpart KKKKa monitoring proposes.

Sources should be able to use a NO_X CEMS installed, maintained, and operated following the procedures in Part 75 and a QA Program based on the Part 75 requirements as is allowed, without approval, under Subparts KKKK and GG. Requiring approval to use a CEMS that meets Part 75 requirements places an administrative burden on EPA, states, and sources for no reason.

EPA should also remove the restriction to use Part 75 CEMS for sources that have post-combustion NO_X controls. The Agency may have included this restriction because it wanted to apply certain Part 60 QA/QC provisions that are more stringent at low concentration levels. However, requiring an affected source that must follow all the Part 75 certification and on-going QA/QC procedures to also meet all the Part 60 requirements will create confusion and unnecessarily impose duplicative requirements. If the application of Part 60 provisions that may be more stringent for low concentration measurements is the underlying reason for the prohibition, EPA should instead allow the use of Part 75 but include the specific additional Part 60 requirements, if any, that it proposes are necessary as it has done for other rules.[2] If the concern is ensuring the accuracy and linear response of the CEMS at low levels, the Agency could require that a cylinder gas audit (or linearity check) be performed for spans ≤ 30 ppm, which is not required under Part 75, as is additionally required where Part 75 CEMS data can be used under Subpart Da of Part 60 and Subpart UUUUU of Part 63.

Support Removing the Requirement for State Approval to Use Part 75 Monitoring Options Under KKKK and Recommend Removing This Administrative Burden in Similar Sections

In §60.4340 (b)(iv), EPA is proposing to remove the requirement for sources to get state approval to use the NO_X monitoring provisions in Appendix E of Part 75 or the low mass emission (LEE) provisions in § 75.19. We support the Agency’s proposal to allow sources to use these Part 75 options without requesting approval and believe this revision will reduce the implementation burden for both sources and the states by removing an unnecessary procedural task to allow monitoring options that the agency has already deemed either sufficiently accurate, representative, or conservative for allowance trading purposes.

Since the Agency proposes to remove the state approval requirement to use the Part 75 Appendix E and LEE provisions, the reference in § 60.4355(b) to state approval for these

[2] 40 CFR Part 60 Subparts Da and Db, 40 CFR Part 63 Subparts DDDDD and UUUUU.

sources should also be removed. In a similar vein, EPA should remove the unnecessary administrative burden of state approval to use the procedures in Appendix D of Part 75 as an alternative to quality assure fuel flowmeters under §60.4345(c) or to implement a CEMS QA program consistent with Appendix B of Part 75 under §60.4345(e). The state approval language in § 60.4350(d) and § 60.4374(e) also provides no benefit and should be removed.

Need to Include a Minimum Gross or Net Output Value for Calculating Emissions Rates
The Agency has proposed to include "diluent cap" values that define a default minimum CO_2 (or maximum O_2) concentration that is used to calculate the emission rate during low load operation. These diluent caps, which the Agency has employed in other rules to address a fundamental issue where slight variations or errors in the diluent concentration measurement at low concentrations, can significantly influence the reported emission values. In common parlance, the "math blows up" as the value in the denominator of the equation approaches zero.

The same principle applies to calculation of an output-based emission rate where, instead of CO_2 (or 20.9 – O_2) in the denominator, the NO_X mass is divided by gross or net MW output. When a combustion turbine is in startup, there may be little or no load produced by the turbine (and HRSG). Just like with the diluent concentration when calculating a lb/MMBtu value, the "math blows up" and the output-based emission rate might be undefinable (if MW=0) or a slight error in the measured load could cause the output-based emissions to be significantly over-reported. To address this issue, the Agency needs to include a minimum output value that would be used in Equations 1 and 7 when the applicable gross or net output falls below that threshold. This approach would be similar to the default electrical load value of 5% of the maximum output that is applied to calculate output-based emission rates for such hours under Subpart UUUUU of 40 CFR Part 63.

Clarify How to Treat Compliance Averages that Do Not Meet the Minimum Data Requirements and Downtime Reporting
§60.4350a (g) and (h) appear to be intended to define the minimum amount of valid data required to calculate emission rates used to determine compliance. The proposed language in §60.4350a (g) states "if the 4-operating hour period contains more than one operating hour with no data points (one or more continuous monitors was out-of-control for the entire hour), report the 4-operating hour rolling average NO_X emissions rate determined for the period as occurring during a period with monitor downtime." §60.4350a (h) says "report any 30-operating day periods for which you have less than 90 percent data availability as monitor downtime."

The proposed language is confusing because it could be interpreted as treating the data for the whole averaging period as downtime in situations where only a portion of the data for the period is missing or out-of-control. Consistent with the general reporting requirements[3] and the proposed requirements in §60.4380a (b)(2) and §60.4385a (c)(2), the proposed Subpart KKKKa CEDRI compliance reporting spreadsheets in the docket indicate that you would report downtime based on the availability of the hourly CEMS data. Thus, following standard downtime reporting, you would not report the whole 4-hour or 30-operating day as downtime if you were only out-of-control for a portion of the period. Treating the whole averaging period as either available or downtime would also be complicated by the fact that compliance is based on rolling averages; even though you might not have data for every hour in one rolling average period, you might have all the data for another rolling average period even though the two periods overlap and "share" some of the same hourly values.

Presumably, in §60.4350a (g) and (h), the Agency intended to express that an average emission rate that is used to demonstrate compliance can only be calculated when you have the requisite amount of valid hourly data. EPA should revise the language to clarify its intent. For example, "calculate a 4-operating hour rolling average NO_X emissions rate for any 4-operating hour period when you have valid CEMS data for at least three of those hours (e.g., a valid 4-operating hour rolling average NO_X emissions rate cannot be calculated if one or more continuous monitors was out-of-control for the entire hour for more than one hour during the 4-operating hour period)."

This same issue should also be addressed in the proposed language in §60.4374a (h) and (i).

EPA Should Not Require a 90% Availability Requirement for Calculating 30-day Averages

If you are complying with the output-based standard, the rule states that you are to "report any 30-operating day periods for which you have less than 90 percent data availability as monitor downtime." As discussed above, this language is ambiguous, and one hopes that the provision will be clarified, but it would seem to suggest that EPA's intent is for you to calculate an average emissions rate only when you have at least 90% data availability during that 30-day operating period. However, while sources that operate NO_X (or SO_2) CEMS typically have monitor availability in excess of 90%, the availability is typically calculated and reported over a longer period (e.g., under Part 75, monitor availability is calculated based on the last 8,760 unit or emission stack operating hours, i.e., for a period of a year or more). In contrast, there are many events that you might unexpectedly encounter over a 30-operating day period that might introduce more than 72 hours of missing or out-of-control data and cause you to fall below 90% availability for a 30-day period. For example, it may take time to reschedule an unexpectedly failed RATA, you may have a supply issue with a critical part or you might have unexpected downtime due to extreme weather delaying safe access to the stack for equipment repairs. Such an event might represent a less than 1% hit to the annual CEMS data availability but cause you to have less than 90% availability for a 30-operating day period and, because the 30-

[3] Based on note in Figure 1 of §60.7(d).

operating day averages are calculated on a rolling basis, such an event is likely to impact several compliance averages.

Particularly given that such events as described above might reasonably be expected, the 90% data availability threshold to calculate a 30-operating day average is counterproductive. In terms of providing a compliance indicator, there is no reason to think that an average is not representative simply because you only have valid data for 644 of 720 hours, for example, over a 30-operating day period especially since §60.4333a(a) requires you to "operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction." In some cases, the variability in the process could suggest an exceedance, if an average is based on limited data, when the issue may have "averaged itself out" if all the data for the period had been available. But, in general, the remaining hours would be expected to be just as representative or indicative as any missing hours might be.

Again, although ambiguous, the current proposal would seem to suggest that a source would simply not be able to calculate or report a compliance average if the CEMS data availability falls below 90% for any 30-operating day period. In general, reporting an emission rate based on an ample amount of the remaining data would seem preferable to reporting no emission rate for a period. To strike a balance between simply reporting no data and avoiding situations where the data are limited (and where variability is more likely to impact compliance), EPA should consider instead requiring that 75% (instead of 90%) of the hourly CEMS data to be to calculate a 30-operating day average and this 75% threshold would be consistent with the 3 out of 4 hour requirement applied to 4-operating hour averages.

EPA Should Extend the Period for Assessing Minimum Availability

Separate but related, §60.4345a(g) states that "at a minimum, non-out-of-control CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-operating day rolling average basis." As discussed above, while NO_X and SO_2 CEMS typically have monitor availabilities above 90%, the availability is usually calculated over a longer period and such high availabilities would not consistently be achieved on a shorter-term basis since, as described above, there are various events that might unexpectedly cause you to incur missing or out-of-control data for a few days. The potential to fall below the 90% threshold may also be exacerbated if a source uses the Part 60 calibration criteria where "backwards" invalidation is applied back to the last passing calibration whenever the drift exceeds four times the performance specification. In such cases, which might be coupled with additional downtime to address any underlying equipment issue, you are likely (albeit unexpectedly) going to invalidate the last 24 hours of data back to the last daily drift check. Preventative maintenance may reduce these events, but sometimes equipment just fails and unexpectedly needs repair or adjustment. While such events might cause one to fall below 90% over a 30-day period (and, which would likely affect multiple 30-day averages, given the nature of rolling averages), in a broader context, such an event might represent less than a 1% drop in the availability on an annual basis. If EPA retains a 90% minimum CEMS data availability requirement, EPA should, at a minimum, extend the period over which the availability is assessed. If the requirement is retained, we recommend that the availability for Subpart KKKKa be calculated based on the last 8,760 unit or emission stack operating hours consistent with how it is calculated under Part 75.

Performance Test Options Should Include the Use of the Initial CEMS Compliance Average
The proposed provisions in §60.4405a state that you must perform a RATA that serves as your performance test when you use a CEMS to demonstrate compliance for NO_X. While a RATA is required for certification and ongoing QA/QC of the CEMS, using the RATA as a performance test is problematic because it would create a requirement to demonstrate initial compliance with a standard over an averaging period that is inconsistent with how compliance with the limit will be demonstrated on an ongoing basis and for which it was established. More fundamentally, the requirement to use a RATA as an initial performance test is just unnecessary since the first compliance average on a 4-operating hour or 30-operating day basis, as applicable, and based on the data from the certified CEMS, could be used as the initial performance test similar to how the initial 30-boiler operating day average based on CEMS data is used as the initial performance test under Subpart UUUUU of Part 63.

Support EPA's Inclusion of a Provision to Address Transitional Operating Hours but Recommend that the Agency Move and Clarify this Provision to Address Both NO_X and SO_2
The proposed provision in §60.4380a (b)(3) states "for hours with multiple emission standards, the applicable standard for that hour is determined based on the condition, excluding periods of monitor downtime, that corresponded to the highest emissions standard." This provision seems to address, as would be appropriate, situations such as a transition operating hour where the average load might be ≥ 70% of the base load rating, but where a portion of the hour might reflect operation at lower loads where lean premix combustion may not have started or where ammonia (or urea) for a unit with SCR might not yet be injected due to temperature constraints.

Such a provision would also address hours when a unit is switching from one fuel to another Such language could address the impact of fuel switching both for NO_X as well as SO_2, but, as proposed, the allowance is only included in §60.4380a, a section addressing excess emission and downtime reporting for NO_X, and is not found in the next section §60.4390a that addresses excess emission and downtime reporting for SO_2.

Currently, the provision is buried in a section discussing how to report excess emissions and downtime where it seems out of place and easy to overlook. We would recommend moving the sentence to the end of §60.4320a(b)(1) where the requirement to determine the applicable NO_X emission standard on an hourly basis is first introduced (and similarly addressing SO_2). We also recommend adding a statement to the effect of “if a unit operates at 70 percent or less of its base load rating for any portion of the hour, the emission limit(s) in Table 1 for combustion turbines operating at 70 percent or less of base load rating shall apply for that hour.”

Support for Excluding Monitor Downtime Periods when Determining the Heat Input or Output Weighted Limit for a Compliance Averaging Period

The provision in §60.4320a(b)(1) includes the conditional phrase “excluding periods of monitor downtime, which we interpret as stipulating that you would only include the hours when valid, CEMS data are collected when determining the heat input or output weighted emission standard that applies for a given compliance average. We support this provision because it would ensure that the limit that is applied would reflect what is achievable for the portion of the averaging period for which valid data is collected. However, we would suggest including this detail in §60.4350a and §60.4350a where the use of the weighting equations (Equations 5, 6, 10, and 11) is covered.

Clarify Provisions Indicating when Monitor Downtime is Reported

§60.4380a (b)(2) and §60.4390a (c)(2) indicate that downtime for an operating hour must be reported if “data for any of the following parameters are either missing or out-of-control: NO_X concentration (SO_2 concentration in §60.4390a (c)(2)), CO_2 or O_2 concentration, stack flow rate, heat input rate, steam flow rate, steam temperature, steam pressure, or megawatts.” While each of the provisions ends with “you are only required to monitor parameters used for compliance purposes,” we recommend that the provision further clarify the requirement by revising the provisions to read “…data for any of the following parameters that you use to calculate the emission rate, as applicable, used to determine compliance, are either missing or out of control…”

The Proposed Rule Only Incidentally Applies to Emissions from Fuel Preheaters when those Emissions Are Vented through the Combustion Turbine or HRSG Stack

The applicability statement in §60.4305a(a) states that “…this subpart does apply to emissions from any associated HRSG, duct burner(s), and fuel preheater(s) that are associated with a combustion turbine subject to this subpart.” Any emissions from fuel preheaters are typically addressed separately from those from a combustion turbine or HRSG. The proposed rule does not seem to include any provisions that would address separately emitted emissions from fuel preheaters. If the emissions from a preheater are vented through the CT or HRSG stack, the emissions from the preheater would be measured along with the CT and HRSG emissions, but this is not usually the case.

Combustion Turbines that Share a Common Exhaust Stack Should Be Able to Demonstrate Compliance on a Combined Basis Regardless of Whether the Units Share a HRSG and/or an Electric Generator

In the proposed rule, §60.4320a(b)(4) states “if you have two or more combustion turbine engines connected to a single electric generator, each of the combustion turbine engines must individually meet their respective, applicable NO_X emission standard as determined using table 1 to this subpart." However, regardless of whether the units share a common generator, any units that share a common exhaust stack should be able to demonstrate compliance on a combined basis at the common stack. Given the configuration of some units, it may not be practical to measure the NO_X from each unit, where there is insufficient duct run to install a CEMS or meet reference method sample location siting requirements. Likewise, if the units share a common generator, one cannot independently measure the electrical output from each turbine for a source that elects to demonstrate compliance with the output-based standard.

Any combustion turbine that exhausts through a common stack (regardless of whether it is a HRSG stack) can measure the emission at the common stack and should determine the applicable emission limit for each hour on a prorated basis, as our comments recommend, for configurations involving multiple combustion turbines sharing a HRSG. If the units share a common generator and demonstrate compliance with the output-based standard, the sources would first need to apportion the output from the shared electrical generator, potentially using heat input, to estimate the amount of the output from each turbine for the purpose of weighting the emission standard that would apply for the hour for the respective turbines. For each hour, the combined output from all units in the configuration could be used to determine the emission rate for each hour and for weighting the hourly emissions for the 30-operating day average. In such a scenario, each CT you would still be meeting the applicable limits for both CTs but on a combined basis.

Delete Provision Suggesting Approved Petition Requirements Can Change at Any Point
§60.4320a(c)(3) indicates that the owners/operators of a combustion turbine that burns by-product fuels can petition the administration for a facility-specific NO_X emission standard. However, the proposed last sentence in §60.4320a(c)(3) (ii) states that "if the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point."

The Agency should strike the last sentence since it creates a precarious and capricious situation for sources and does not give a facility certainty with the emission standard approved by the Agency. The Agency would have the opportunity to develop a meaningful response to the petition for a facility-specific emission standard and can ask for the information necessary to establish an appropriate limit. Of course, if there are potential changes to the by-product fuel composition or the process that are not addressed by the original petition, the facility-specific NO_X emission standard may need to be reconsidered. Otherwise, facilities need to have certainty that they can continue to use facility-specific NO_X emission standards that have been reviewed and approved by the Agency.

Provide the Same Flexibility for Performance Tests Under KKKKa as Provided in KKKK
EPA should revise the proposed performance test frequency requirements §60.4333a (b) to provide the same flexibility as is allowed in Subpart KKKK for tests conducted once every two years, which is defined as "no more than 26 calendar months following the previous performance test," and as is proposed for annual tests, which is defined as "no more than 14 calendar months following the previous performance test" in Subpart KKKK.

EPA Should Allow a Custom Testing Schedule for Any Facility
Currently, as proposed, §60.4333a(b)(5) restricts the use of a custom testing schedule to facilities consisting of "no more than five similar stationary combustion turbines." The proposed rule requires that "a performance test is conducted on each affected facility at least once every 5 calendar years," so even if the provision was extended to more than five units, all units would be tested at least once every five years, and the Administrator or delegated authority could specify other conditions such as testing one or more units per year, if deemed appropriate, just as it might stipulate for a smaller groups of similar units.

Sources Meeting Fuel Standards by Contract or Tariff Should Be Exempt from Monitoring
§60.4415a indicates that you can comply with the initial performance testing requirements by submitting fuel records (such as a current, valid purchase contract, tariff sheet, transportation contract, or results of a fuel analysis) and thereafter, under §60.4333a(d)(3) by maintaining such records. However, a more streamlined approach would be to follow the approach in Subpart KKKK to exempt sources from monitoring when the total sulfur content of the fuel based on a current, valid purchase contract, tariff sheet or transportation contract for the fuel meets the applicable fuel-based standard. Exempting sources from the monitoring requirements, including the "initial performance test," as allowed in 60.8(b)(4), where the Administrator "waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard," would also address the awkward issue of whether such a non-stack test "performance test" requires notification.

Allow Time to Re-establish Parameter Ranges when a Turbine is Exchanged
Under the proposed rule, you must reestablish any "water or steam to fuel ratio and parameter continuous monitoring system ranges" whenever the turbine is "replaced with an overhauled turbine engine as part of an exchange program." §60.4342a(b) allows 45 calendar days after the next operating day to complete the "recalibration" (presumably this means the re-establishing the ranges) for sources that have "not operated for 60 calendar days prior to the due date." Likewise, sources should be given 45 days to reestablish the ranges from the first operation after a turbine is exchanged.

Use of Stack Flow Monitors to Calculate NO_X Mass Should Be Optional
§60.4345a(a)(3) states that if you comply with an output-based emissions standard, you must

install, calibrate, maintain, and operate both a watt meter (or meters) and a stack flow meter. While we concede that watt meters are necessary to determine the electrical output, a stack flow meter is not necessarily required to determine the NO_X mass emissions. The NO_X mass can be determined using a fuel-based heat input value in conjunction with a NO_X lb/MMBtu emission rate or by using a stack flow CEMS in conjunction with NO_X concentration. While determining the NO_X mass using fuel-based heat input is generally preferable given difficulties measuring the volumetric stack flow in some combustion turbine flues, either approach should be allowed as is indicated in 60.4543a(a)(2).

Better Categorize Data Not to Be Used in Compliance Averages

In the proposed rule, several sections indicate that hourly data should not be used for compliance determinations when the CEMS or parametric data is "out-of-control." While we agree with the presumed intent, the use of the of the term does not convey all the situations where the data would not be considered valid for compliance determination. First, the definition of the term only applies to CEMS data and not the other parameters that may also be used to convert the CEMS data to units of the standard (e.g., steam flow rate, temperature, pressure and megawatt data). Second, it does not capture situations where the CEMS might be in-control with respect to the required QA/QC but still invalid under Part 60 or Part 75 because insufficient data was collected (e.g., due to periodic maintenance or calibrations) or when the data are simply missing. To resolve the issue, we suggest using the term valid or invalid, as appropriate to better capture the different scenarios where data may or may not be used for compliance averages.

NO_X lb/MMBtu Values Do Not Need to Be Recorded in All Cases

§60.4350a(c) states that you "must calculate and record the hourly average NO_X emissions in units of lb/MMBtu" for every hour when data is obtained. However, it is not necessary to calculate a NO_X lb/MMBtu value if a source elects to demonstrate compliance with the output based standard and chooses to calculate NO_X emissions using a NO_X concentration monitor and a volumetric stack flow monitor.

Correct Equation 6 to Properly Calculate the 30-day Emission Rates and Emissions Standards

Since the equation addresses output-based emission rates, to properly weight the emission rate and applicable emission standard, Equation 6 and the description of the variables in §60.4345a(h) should be revised to:

$$E = \frac{\sum_{i=1}^{n}(E_i \times P_i)}{\sum_{i=1}^{n} P_i} \quad \text{(Eq. 6)}$$

Where:
E = 30-operating day average NO_X measured emissions rate combustion turbines (lb/MWh or ng/J),
Ei = Hourly average NO_X emissions rate or emissions standard for valid operating hour “i” (lb/MMBtu or ng/J),
Pi = Total gross or net energy output from stationary combustion turbine for valid operating hour “i” (MWh or J), and
n = Total number of operating valid hours in the 30 operating-day period.

Revise Criteria for Single Point Sampling

§§60.4400a(c)(2)(ii)(B) and (C) include separate criteria to use single point sampling if the NO_X emissions are less than or greater than 15 ppm at 15 percent O_2. Having two sets of criteria is unnecessary even if the Agency wants to ensure accurate measurements at low emission levels because the requirement for NO_X ppm is in relative terms. If the 5% criteria is applied at all concentrations the criteria at 15 ppm would be ±0.75 ppm and the criteria at 3 ppm would be ±0.15 ppm, which is already absurdly low, and applying the proposed 2.5% criteria would cut the allowed variation in half, making the option impractical. While we would also advocate an alternative specification of 1 ppm variation from the average, we recommend at least applying the 5% criteria for all concentrations levels and allowing the criteria to alternatively be assessed in terms of the heat input based emission limit units of measure (i.e., ng/J of lb/MMBtu) so that one could factor out excess air variation across the stack that might not really have any impact on the results in terms of the emission limit.

Use First 4-hour or 30-Day Average as Initial Performance Test if CEMS Is Used

Under §60.4405a, the proposed rule states that if you use a NO_X CEMS, you will need to conduct a RATA and report the data as your initial performance test. Using a RATA as a performance test would impose initial compliance based on an averaging time that is inconsistent with the underlying average time of the applicable standard. In the case of a source using a CEMS to demonstrate compliance with the output-based standard, the short-term results of a nine-run RATA might not address the variability in the emissions or process (or measurement uncertainty) that would be addressed by a 30-operating day average.

Using a RATA or other stack test is unnecessary for sources using a certified CEMS for compliance. Instead, the rule should simply use the first CEMS compliance average as the initial performance test, which is an approach that would mirror the requirements in 63.10011(c) of Subpart UUUUU in Part 63.

Allow for Supplemental or Fresh Air Firing Mode for HRSG Combustion

The last sentence in the definition of Duct burner in §60.4420a states "no additional oxygen is used in a duct burner beyond what is inherent in the exhaust from the initial source." This sentence should be struck since Table 1 includes an emission standard for HRSGs operating independent of the combustion turbine. Such a scenario may include a duct burner equipped with a fresh air firing mode where ambient air is supplied for combustion purposes. Even if some air is added when the combustion turbine is operated, it would not change the fundamental way emissions may be monitored or compliance options.

Proposed KKKKa Definition of Stationary Combustion Turbine Is Overly Expansive

The proposed definition for stationary combustion turbine in §60.4420a is overly expansive with the inclusion of add-on control equipment, fuel heaters, related on-site photovoltaics and integrated energy storage, etc. and is at odds with the rule's applicability provisions. On-site photovoltaics and energy storage are different types of generation and energy facilities, and their inclusion inappropriately redefines the source. In contrast, the definition in Subpart KKKK is appropriate and should be retained.

Do Not Require Notification for Documentation or CEMS-based "Performance Tests"

EPA should add an exclusion to Table 2 for the notification requirement in § 60.8(d) for "initial performance tests" if the initial compliance determination is made using documentation (if this requirement is not exempted as recommended) or if initial compliance is determined using CEMS data (if the initial compliance average is used). For CEMS-based compliance, notification of initial certification tests will still be required and essentially serve as a functional notice of the potential beginning of the initial compliance average data collection period pending the successful completion of the CEMS certification process.

ERT Should Not Be Required for Reporting RATA or Performance Test Data

While we generally support electronic reporting, as we have commented to the Agency in the past, we find EPA's Electronic Reporting Tool (ERT) to be a very poorly suited tool for reporting performance test data, and we therefore object to EPA imposing its use under Subparts KKKKa, KKKK, and GG. Agora has had the unfortunate opportunity to have significant experience with the ERT because of the Agency's continued (but unwarranted) application of the ERT for reporting under different rules and for Information Collect Requests (ICRs). In addition to reviewing and preparing ERT files for various sources, Agora has developed software tools to compile the data and verify the calculations from a large portion of the ERT files submitted during the MATS ICR as part of EPRI's effort to help utilities ensure the quality of the data they provided the Agency. We have also developed tools for submitting data in XML for MATS based on the ERT XML schema. We understand how the ERT is intended to work, the details of the format and the problems that implementing this format would present.

While EPA has imposed the ERT for tests performed under ICRs for various rulemakings and for some NSPS sources, the ERT remains very poorly suited for reporting performance test data, particularly if one of the goals is to lessen the burden on the regulated community. The ERT fails with respect to the stated goals expressed by the Agency of “saving time and resources, simplifying data entry” and “eliminating redundancies,” especially for utility sources that already submit RATA data electronically.[4]

Introduced in 2005, the ERT was not specifically designed as a tool that sources and testers would use just to report performance test results; it apparently had a broader scope. Based on the information from EPA's website:

> The ERT is used to electronically create and submit stationary source sampling test plans to regulatory agencies and, after approval, to calculate and submit the test results as an electronic report to the regulatory agency. The ERT replaces the time-intensive manual preparation and transcription of stationary source emissions test plans and reports currently performed by contractors for emissions sources and the time-intensive manual quality assurance evaluations and documentation performed by State agencies.[5]

EPA has stated that the ERT was created to "streamline" collecting test data for developing emissions factors. Somewhere in its genesis, however, the "streamlined" approach morphed,[6] and it was transformed into an "all-in-one" tool that sources would use to address all aspects of a performance test. The objective seems to have been that testers, sources and agencies would use the ERT to develop and exchange test plans prior to conducting the test. The testers would then use the ERT to enter the data from the test to calculate emissions and generate a report, and the ERT would serve as the compendium of the data for submission, which would allow state agency personnel to more readily access the data from the test. This vision was never embraced by either testers or states, for good reasons.

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[4] Electronic Reporting Requirements for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Rules Memorandum, EPA Measurement Policy Group (August 8, 2018), p5.

[5] http://www.epa.gov/ttnchie1/ert/ (5/10/2015)

[6] 74 Federal Register 52726 (October 14, 2009)

We believe that the ERT suffers from fundamental design flaws. First, the ERT relies on a Microsoft Access database that encumbers data entry. Likewise, other than generating a simple report, it is an awkward tool for state agency personnel who want to use the data for other purposes unless they have a working knowledge of Microsoft Access and some details about the table structure underlying the application or of the XML schema that the ERT generates or that might be used as an alternative to the ERT under this rule (thus, falling flat on the objective to allow “air agencies and EPA to review reports and data more quickly”).[7]

The reporting and calculation features do not easily lend themselves to complicated situations or where variants of methods may be used by petition that require more detail to be documented. Instead of reducing the reporting, the requirement to use the ERT increases the reporting burden. The testers already have tools that they have developed and verified over time and that they can certify to provide results that are to the best of their knowledge, accurate and true. The testers or sources have often had to manually re-enter data into the ERT to meet the reporting requirements. While the Excel templates allow some of the data to be imported from spreadsheets, the templates do not address all the data, and the ERT adds extra steps to the reporting process that cannot be automated.

Another fundamental flaw of the ERT from a regulatory perspective is that it does not allow sources to report the values that they believe actually represent the results of the performance test. The tool only allows the source to enter the raw data and then it calculates a final emission rate value that may not be consistent with the value the source knows to be accurate and true. Thus, the ERT prohibits sources from actually meeting the rudimentary requirement to report the "results" of the performance test.

Because the ERT was designed as an all-in-one reporting tool with a myriad of functions, it includes more data entry than is required under §60.8(f)(2), and it is difficult for sources to know what data is required when the rules simply propose that the “data must be submitted in a file format generated using the EPA’s ERT” or following the ERT’s XML schema. If the Agency truly seeks to reduce the reporting burden on the regulated community and provide information that is most useful to the agencies that may review the data, it should consider

[7] Electronic Reporting Requirements for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Rules Memorandum, EPA Measurement Policy Group (August 8, 2018), p6.

how to best report the data to achieve these goals. The ERT does not do so, because it includes a significant amount of information that more appropriately and efficiently can be reported electronically using a PDF of the complete stack test report.

EPA was apprised of serious concerns regarding the using the ERT in the feedback that it received in response to the original ANPR published on the issue of requiring electronic reporting for the purpose of improving the quality EPA's emissions factors program that it issued in 2009.[8] For example, in his December 14, 2009 letter, the Director of North Carolina Division of Air Quality stated that "the NCDAQ has found the current reporting tool (Electronic Reporting Tool, ERT) to be difficult to use and technologically outdated."[9] A group of electric generators expressed that the "ERT is not a straightforward and simple program to use. It requires the user to manually enter vast amounts of data, some of which is repetitive and has no direct influence on the emissions test result." [10] On behalf of National Association of Clean Air Agencies (NACAA), Mr. David Thornton and Mr. James Hodina stated in their December 14, 2009 letter that "NACAA is concerned that the existing Emissions Reporting Tool (ERT) is not based on current technology and would not be an effective platform on which to build a national emission factor program."[11]

In response to these and other comments, EPA should have abandoned the ERT years ago and started developing an alternative electronic reporting option. Instead, even though it has expended significant resources adding new methods to the tool, the ERT is fundamentally unchanged, so the same inherent issues remain. It is still a difficult tool to use that compels sources to enter much more data than is required or necessary. Far from being a validation of the ERT, the experience of the many sources that have been forced to use ERT in the interim continues to highlight the problems and undue effort associated with its use.

The ERT is simply a poor choice for electronically reporting NSPS performance test data. Making its use mandatory is counter-productive by forcing sources to spend more time addressing potential data re-entry and formatting issues related to minor test details rather

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[8] 74 Federal Register 52723 (October 14, 2009)

[9] Comments submitted by B. Overcash on behalf of the North Carolina Division of Air Quality (Docket # EPA-HQ-OAR-2009-0174-0046_attachment_2), p. 1.

[10] Comments submitted by L. Freeman on behalf of the Utility Air Regulatory Group (Docket # EPA-HQ-OAR-2009-0174-0040_attachment_1), p. 1.

[11] Comments submitted by D. Thornton and J. Hodina on behalf of NACAA (Docket # EPA-HQ-OAR-2009-0174-0034_attachment_1)

than focusing attention on the more important QA aspects of the test. Rather than focusing on real compliance issues, reliance on the ERT would waste resources addressing "false positives" and data entry issues or problems with minor test details that do not affect the overall results. The Agency should not let its previous mistakes or the effort it has expended on the ERT cloud its judgment with respect to the need to revise its course now.

Any New Electronic Reporting Elements Should Be Specifically Identified in the Rule

Regardless of the reporting format that is used, if EPA is going to impose new reporting requirements, it needs to define the specific elements that should be electronically reported within the rule. As previously indicated, one of the problems with the ERT is that some of the elements within the ERT are not required under the NSPS. Of course, the information that is not required by the regulation does not have to be reported by sources, but inherent questions over what information is required has the potential to cause serious confusion for sources, create issues during the submission process, and pose problems for EPA and state agencies trying to use the data. More fundamentally, the EPA needs to specifically identify the data within the rule to ensure these details are subject to the proper regulatory review and rulemaking process. If data elements are not included in the rule, stakeholders are stripped of a meaningful avenue to comment on these requirements. While some formatting issues and some technical details might be addressed by reporting instructions outside rule, the rule itself needs to define what elements are to be reported. Having a nebulous reporting requirement, where the “required” information might be changed without a proper rulemaking is not appropriate or tenable. Simply saying the “data must be submitted in a file format generated using the EPA’s ERT” or “submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA’s ERT website” is a woefully undefined format.

Even If the ERT or its XML Schema Are Required for Stack Test Data from Other Sources, They Should Not Be Required for RATAs Conducted for Part 75 Affected Sources.

While not all the turbines that would be affected by the reporting changes are affected by Part 75, many of the units are. In the regulatory impact analysis done by the Agency, 62% of the current turbines identified in the National Emission Inventory were electric utility units.[12] For these sources, all the information needed to document the quality assurance of the CEMS will be reported in the “Quality Assurance and Certification” XML data files (QA files), which sources must submit via ECMPS (as well as in the stack test reports already submitted under Part 60).

[12] Based on information in Table 4 of Regulatory Impact Analysis for the New Source Performance Standards Review for Stationary Combustion Turbines, EPA-452/R-24-016 (November 2024)

The QA files include the RATA results for SO_2 and NO_X CEMS covered under the proposal. Furthermore, the data submitted under Part 75 goes far beyond the information that would be reported in the ERT, including the reporting of hourly emissions data for each CEMS as well as the daily calibration data and quarterly linearity check data. Most electric utility combustion turbines employ the monitoring procedures in Appendix D of Part 75 and are also required to report hourly fuel flow data, fuel analysis results, and fuel flow meter calibration data. The readily available nature and potential usefulness of the Part 75 data is illustrated by the Agency's significant reliance on this information for the Subpart KKKKa rulemaking.[13]

The Agency has successfully used these types of QA records to document CEMS quality assurance test data for 30 years under 40 CFR Part 75 for the Acid Rain and NO_X Budget/Cross State Air Pollution Rule (CSAPR) Programs. These records have been and remain more than sufficient for that task. Similarly, the RATA records are adequate for the purpose of documenting the quality assurance of CEMS used for Subparts KKKKa, KKKK, and GG since the same equipment that is used for Part 75 monitoring will be used under these rules and for emission standards and emission factor development. There is no meaningful reason that the additional ERT reporting requirements should be imposed on Part 75 affected sources even if the Agency requires such reporting for other units.[14]

Miscellaneous Comments

Delete Out-of-Place Input-Based Reference. Delete "if you elect to comply with the applicable heat input-based emissions rate standard, calculate both the measured emissions rate and emissions standard using equation 6 to this subpart" from §60.4350a(h) since this section addresses sources that use the output-based standard.

Delete Unnecessary Tuning References. The proposed rule nowhere establishes a standard or imposes any requirement for combustion turbine tuning. Yet, §60.4390a(c) states "an owner or operator of a stationary combustion turbine that uses the tuning NO_X standard in the compliance demonstration must identify the hours on which the maintenance was performed and a description of the maintenance;" and turbine tuning is defined in §60.4420a. Both of

[13] See "CAPD Data 2023" tab in the Excel spreadsheet (EPA-HQ-OAR-2024-0419-0005_attachment_12) included in the docket.

[14] The lack of benefit of the additional reporting is doubly acute for Subpart KKKK and GG sources since the data from these older units since the data from these sources are unlikely to be used for the analysis of for future NSPS revisions. Moreover, the proposed use of ERT and other additional reporting has clearly not impeded the Agency's ability to access the relevant data and stack test results for these units, especially those subject to Part 75.

these references to turbine tuning should be struck because they are superfluous and may create confusion.

Valid Data Definition. The last sentence of the proposed definition of "valid data" in 60.4420a says that "any data not valid is considered out-of-control data." However, "out-of-control period" is already explicitly defined in 60.4420a; this statement is inconsistent with that definition and would create confusion. The sentence should be struck or, perhaps, revised to express something like: "Any out-of-control data is not considered valid data." To minimize the potential of data being considered out-of-control, the definition should also allow for the use of the probationary calibration/conditional data validation options under Part 75. The definition of valid data should also be expanded to cover other non-CEMS parameters used to convert the emissions data to units of the standard such as steam flow rate, steam temperature, steam pressure, megawatts and ambient temperature.

Base Load Rating Definition. For Part 75, sources are required to report the combined heat input of the combustion turbine and the HRSG and the combined heat input would also be used if you are calculating the NO_X mass for an output-based standard using the hourly NO_X lb/MMBtu times heat input approach. Given that sometimes just the combustion turbine heat input is used while other times the combined heat input is used, we recommend that EPA explicitly state in the base load rating definition in 60.4420a that the base load rating excludes any potential heat input to a HRSG.

Low and Intermediate Load Definitions. While the preamble of the proposed rule discusses that low load units have annual capacity factors less than or equal to 20% and intermediate loads units have annual capacity factors greater than 20% but less than or equal to 40%, neither low load nor intermediate load is defined in the proposed rule language included in the docket. Definitions for these terms should be added to §60.4420a.

Limit Clarification. In Table 1, put colon after ≤ 250 MMBtu/h and > 250 MMBtu/h

Base load rating ≤ 250 MMBtu/h:

Base load rating > 250 MMBtu/h:

to help indicate that this differentiation for determining the limits applies for both units operating at 70 percent or less of the base load rating and for sites north of the Arctic Circle, and/or ambient temperatures of less than 0 °F.

Typo Corrections. Delete the word “either” from §60.4305a(e).

The reference to “paragraph (c)(1)” in §60.4320a(b)(2) should be “paragraph (b)(1).”

The “Combustion Turbines Operating at 70 Percent of Less…” header in Table 1 should read “Combustion Turbines Operating at 70 Percent or Less…”

The ultra-low sulfur diesel standard is 15 ppm. The equivalent to the 15 ppmw is 0.0015 % weight, but §60.4330a(f)(2) shows a value of “0.015 weight percent.” §60.4330a(f)(2) should be corrected to “… no more than 0.0015 weight percent sulfur (15 ppmw).”

Table 1 Header should be: Combustion Turbines Operating at 70 Percent or Less of the Base Load Rating and/or Other Specified Conditions.