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

Prepared for:

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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]

[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.

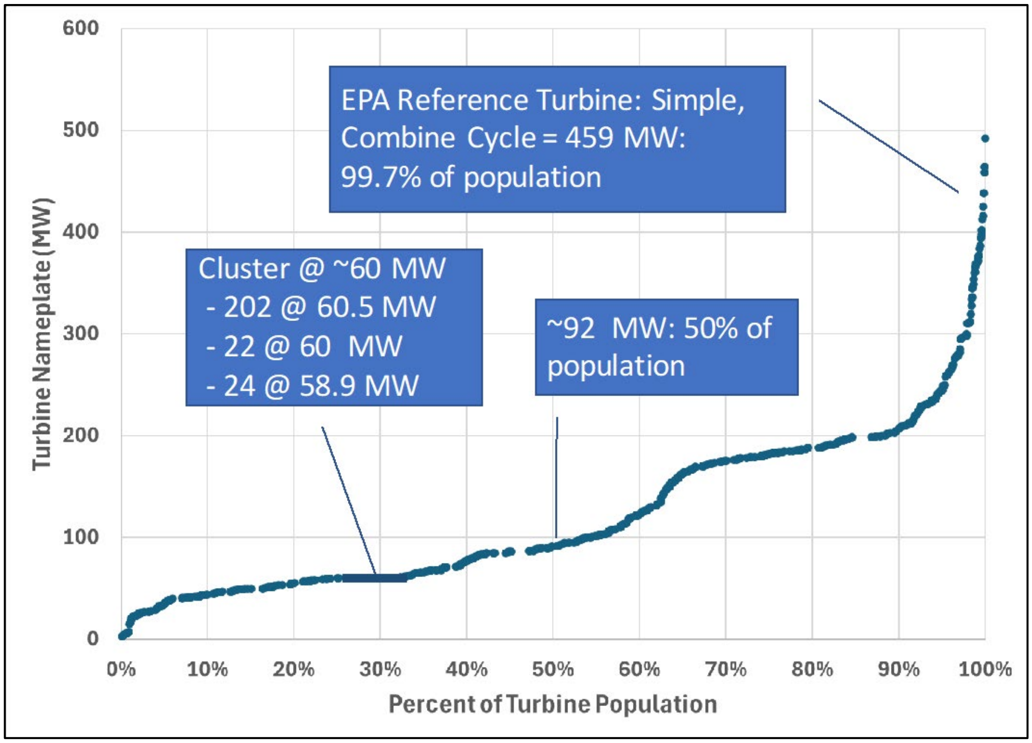

Figure 2-1. Combustion Turbine Population Distribution, by Nameplate Capacity

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

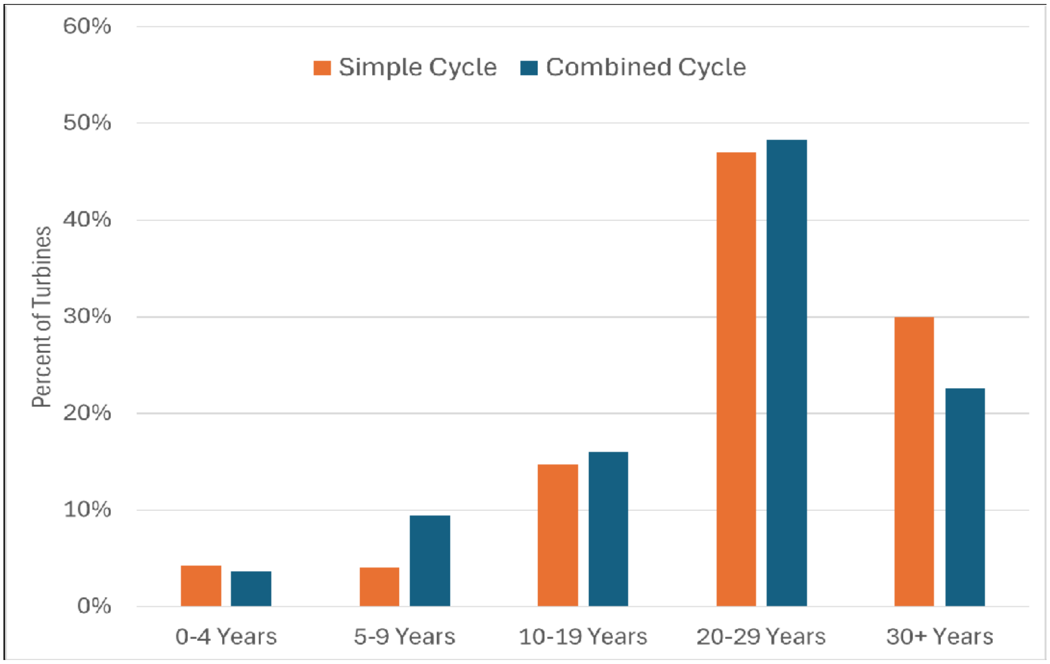

Figure 2-2. Combustion Turbine Population: Percentage by Age for Simple, Combined Cycle

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.

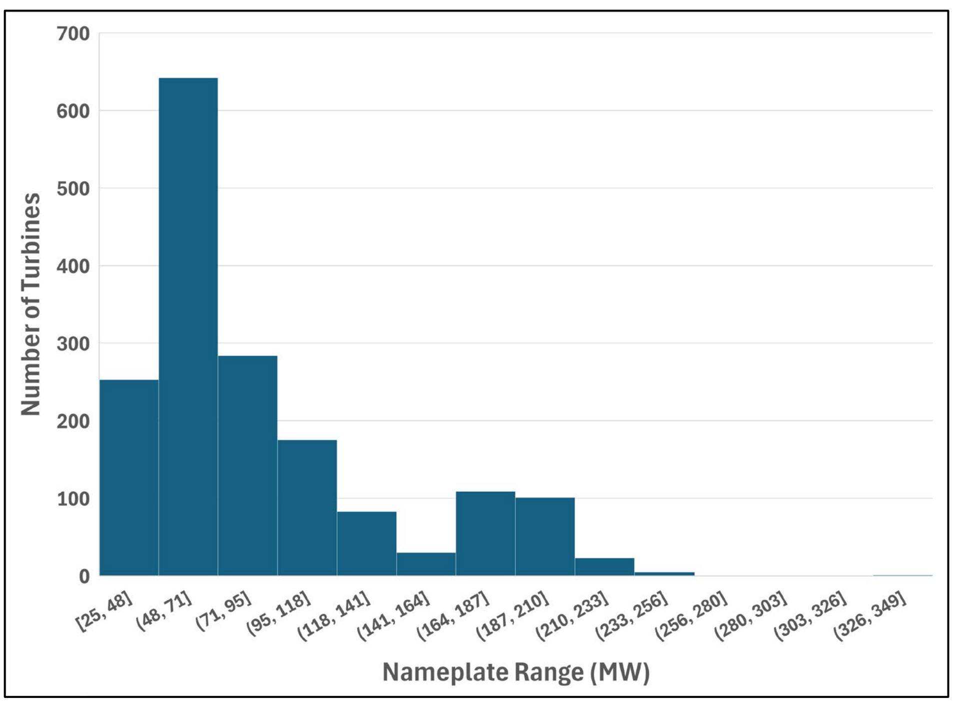

Figure 2-3. Population of Combustion Turbines by Nameplate: Simple Cycle Duty

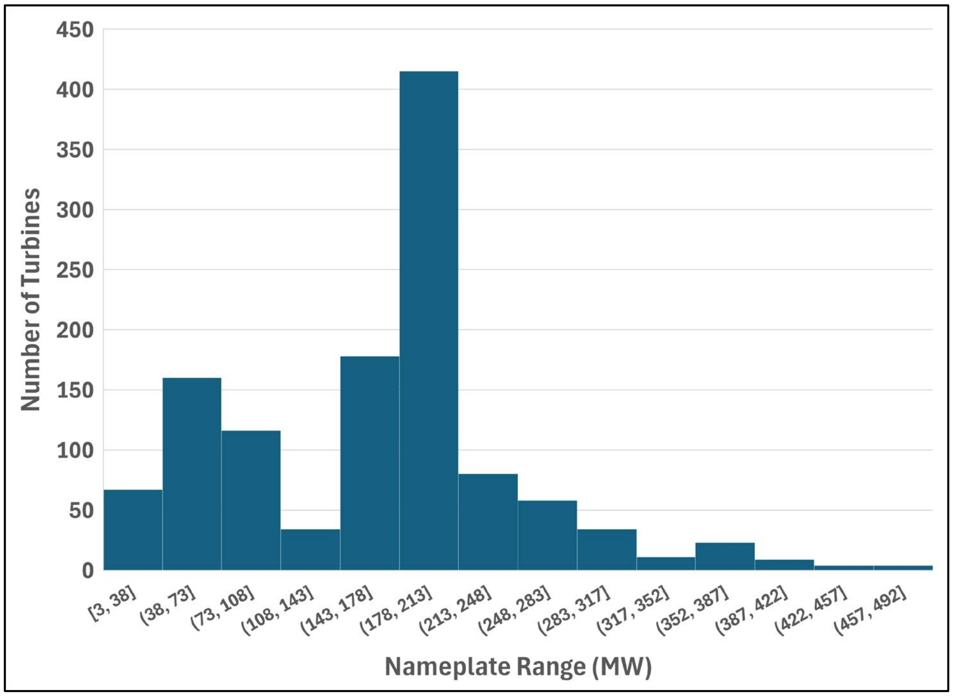

Figure 2-4. Population of Combustion Turbines by Nameplate: Combined Cycle Duty

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		Equivalent Tons NOx/MW per Calendar Year
	12-Month Capacity Factor (%)	NOx ppm (4-hr standard)	
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					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%

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					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%

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					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%

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.

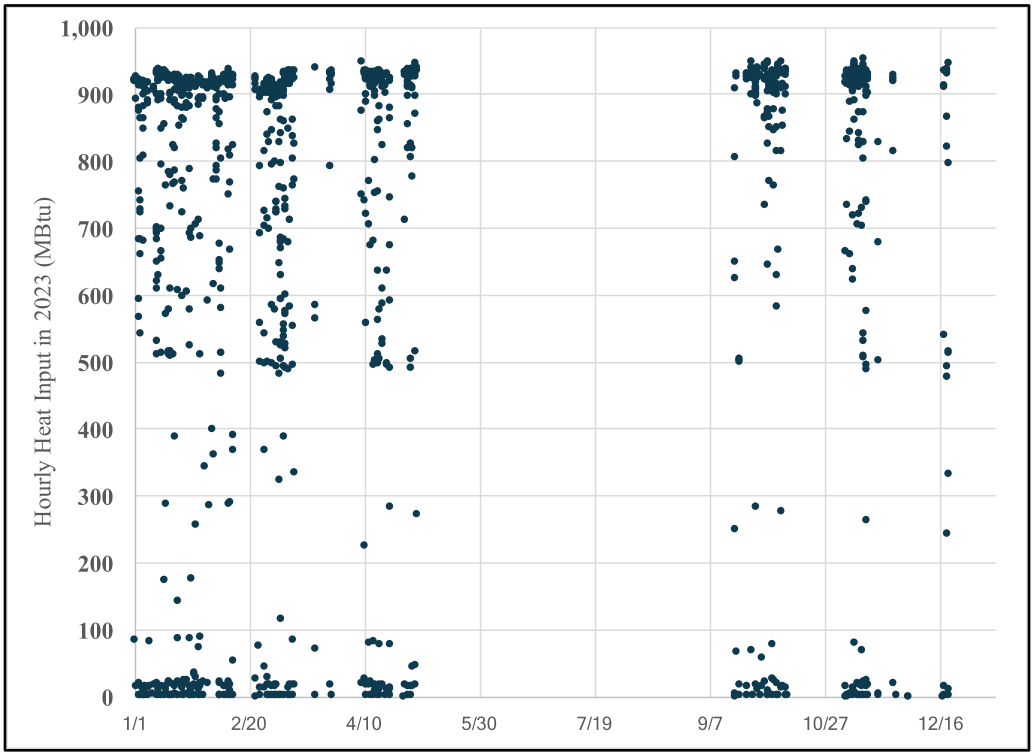

Figure 4-1. Operating Duty for an Ocotillo Simple Cycle Unit

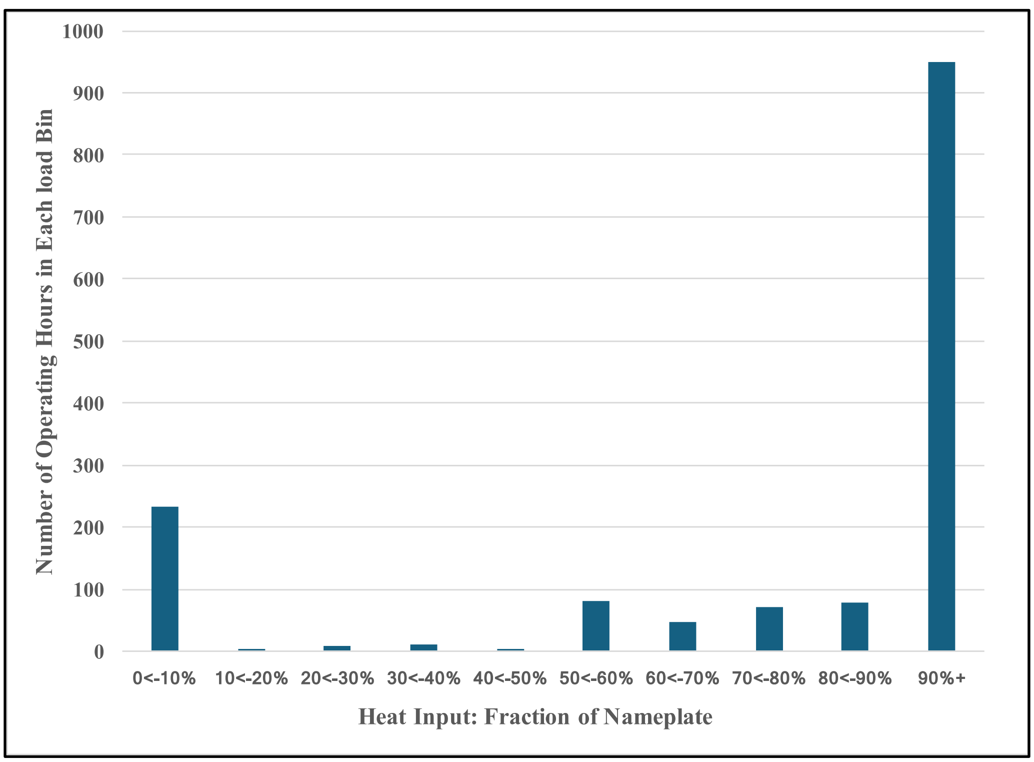

Figure 4-2. Operating Hours in Ten Load Bins: Ocotillo Example Unit

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.

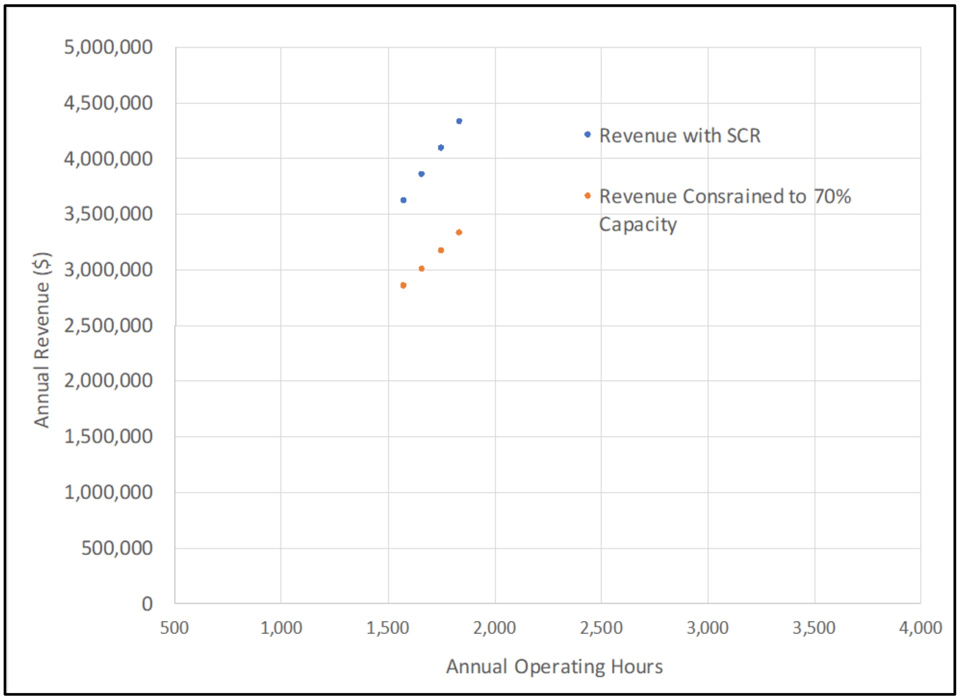

Figure 4-3. FGD Equipped Units: Role of 3-Year Capacity Factor

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.

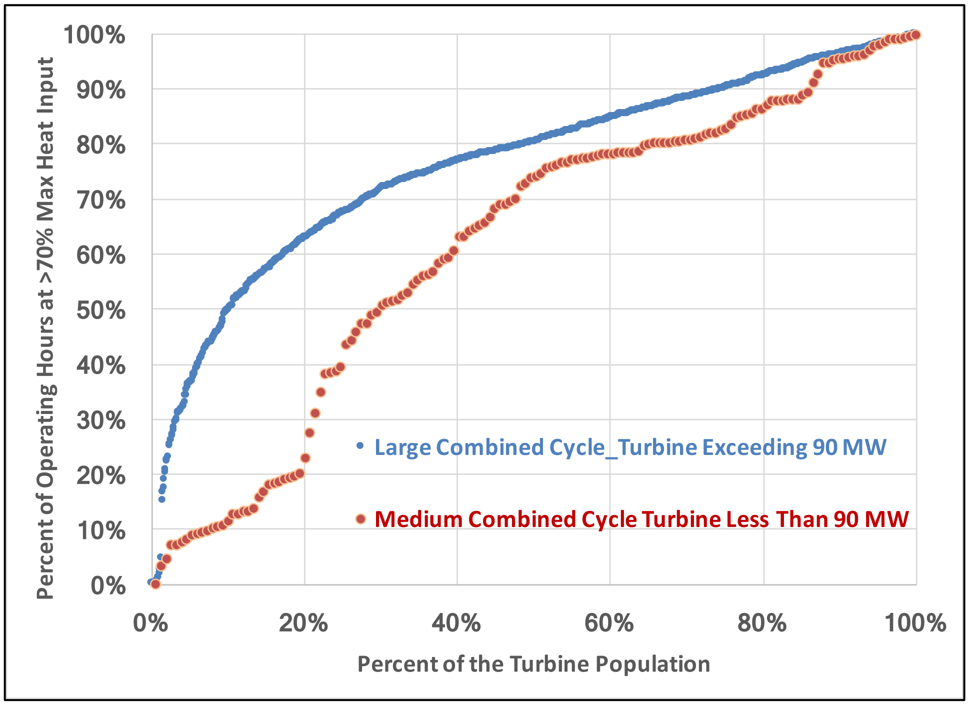

Figure 4-4. Operating Hours Exceeding 70% Load: Medium, Large Combined Cycle Units

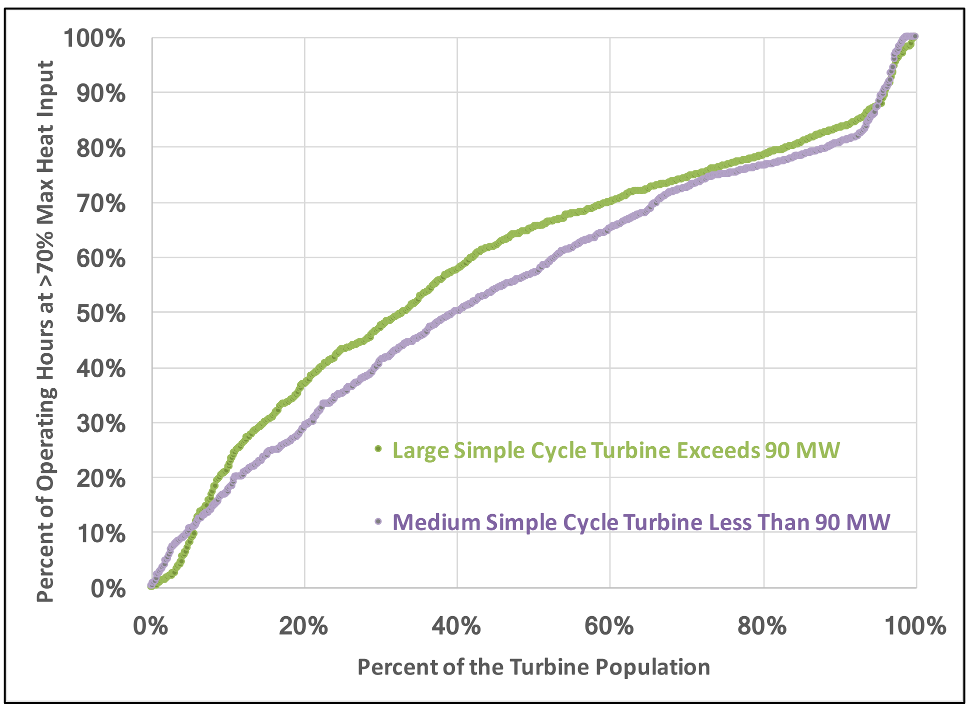

Figure 4-5. Operating Hours Exceeding 70% Load: Medium, Large Simple Cycle Units

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.

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[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.

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[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.

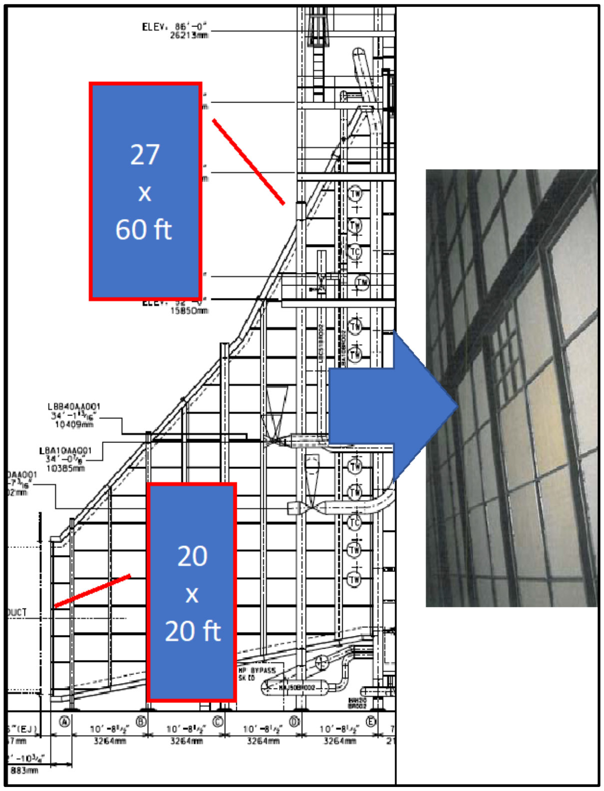

Figure 6-1. Ductwork Between Heat Recovery Steam Generator Inlet, First Tube Bundle

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.

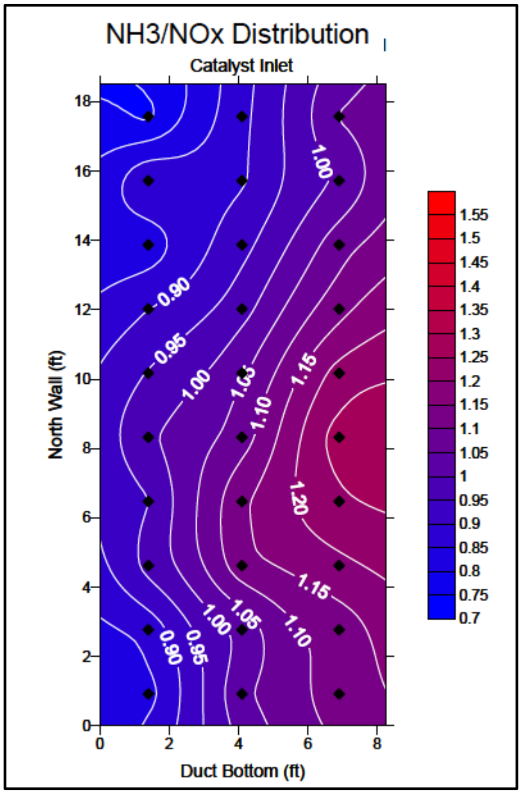

Figure 6-2. NH_3/NOx Distribution: Simple Cycle Application

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.

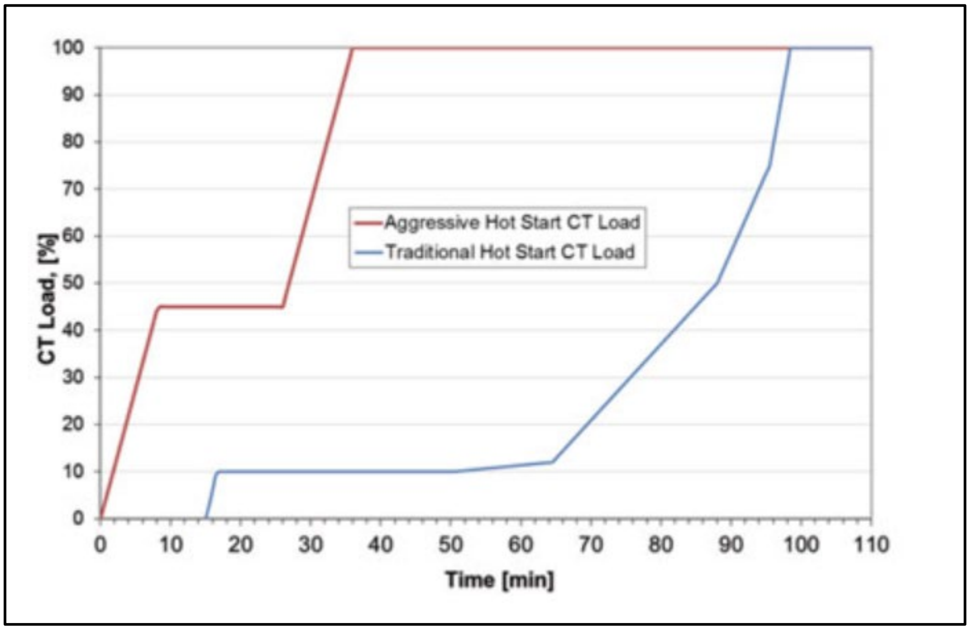

Figure 6-3. Combustion Turbine Load vs Time: Traditional vs. Fast Start Conditions

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).

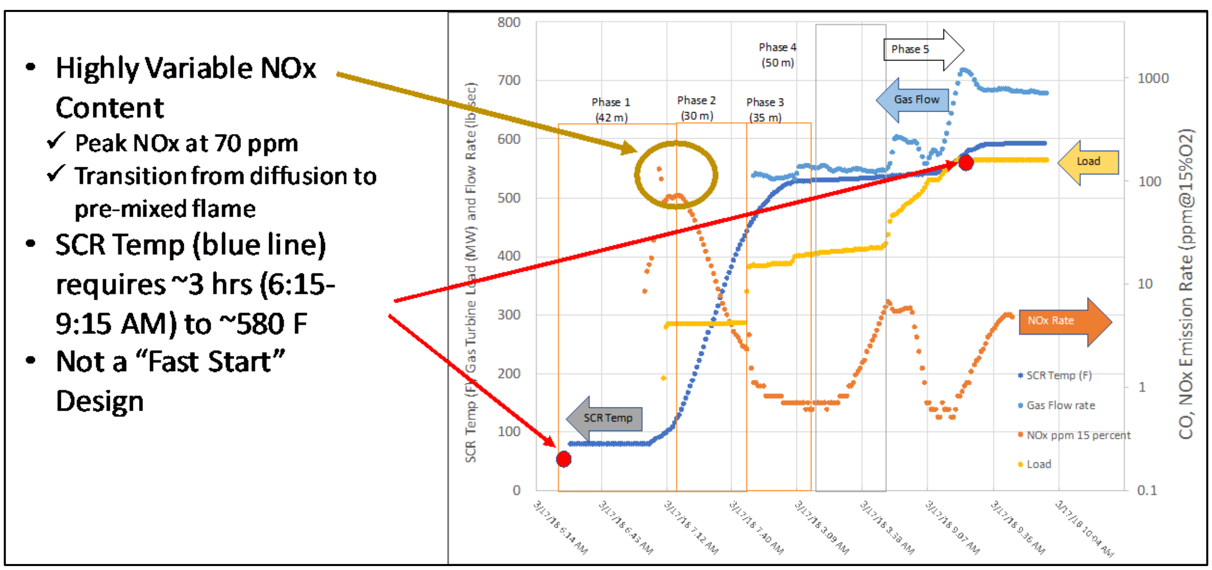

Figure 6-4. Startup Data: GE 7FA:1 x 1 Combined Cycle Arrangement

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.

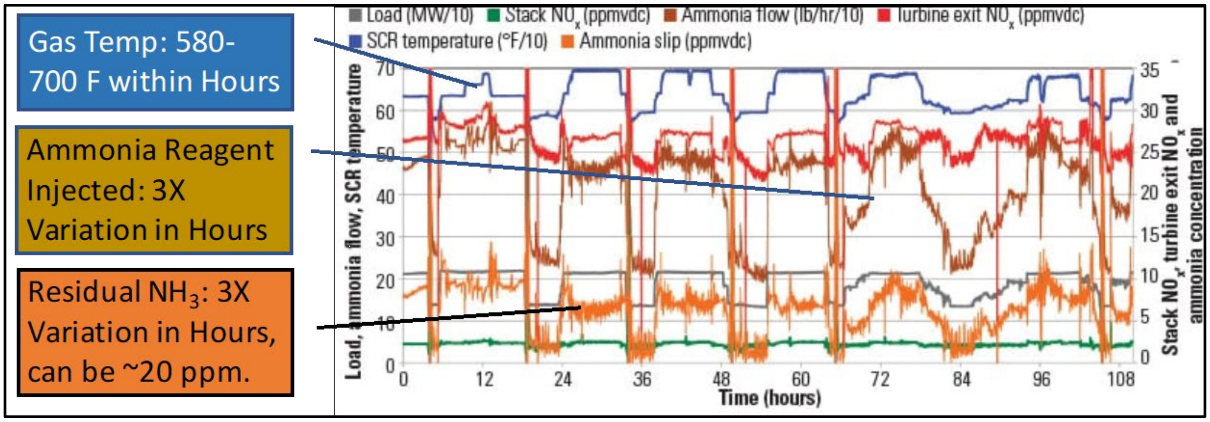

Figure 6-5. SCR Design and Operating Parameters: Highly Transient Conditions

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/.

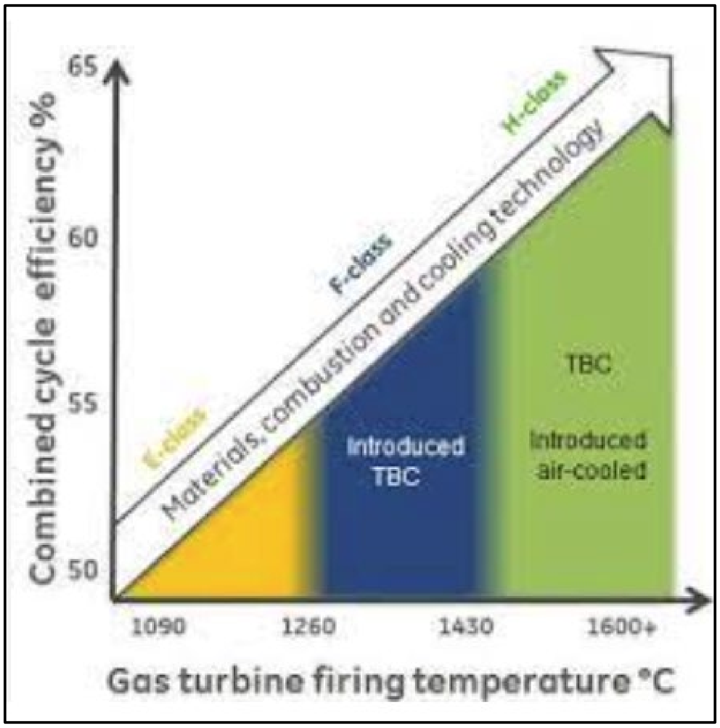

Figure 7-1. Evolution of E, F, and H-Class Frame Engines

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.

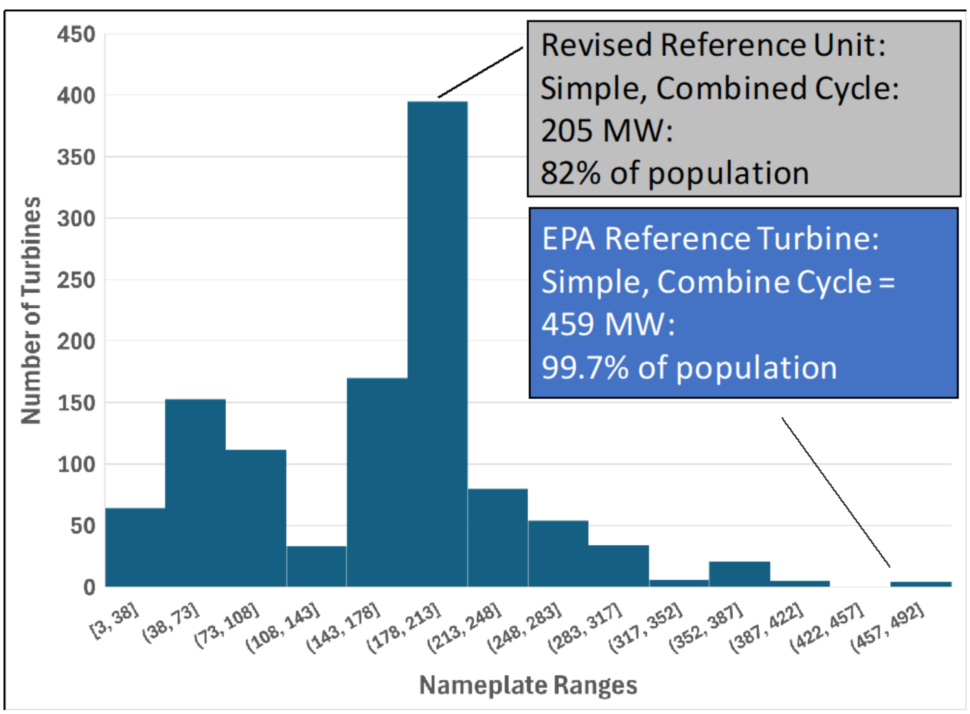

Figure 7-2. Combustion Turbines Population vs Nameplate Capacity

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.

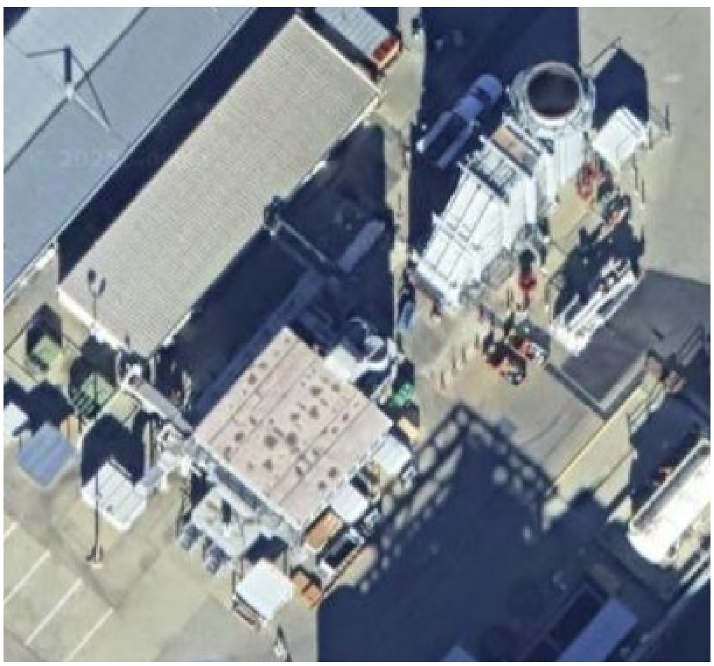

Figure 7-3. Salt River Project Ocotillo Simple Cycle Unit Equipped with SCR

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.

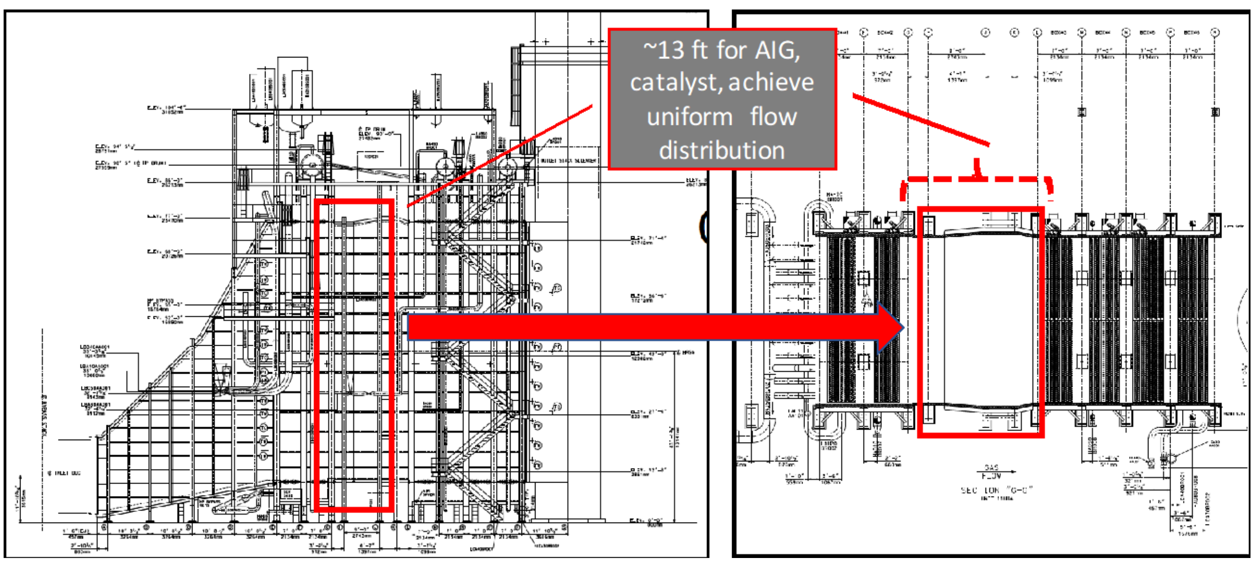

Figure 7-4. Sectional Drawing: HRSG Design to Accommodate SCR

[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.

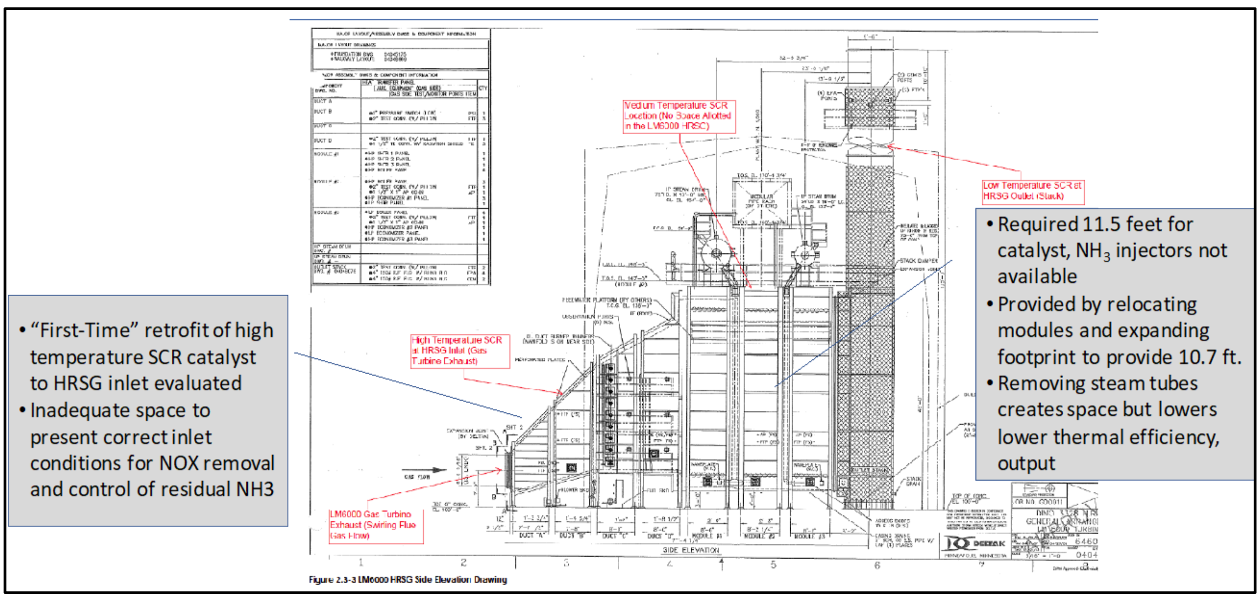

Figure 7-5. Jackson Unit: Options to Retrofit SCR

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

[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.

[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.