

Technical Support Document (TSD)
for the Proposed Revised CSAPR Update for the 2008 Ozone NAAQS
Docket ID No. EPA-HQ-OAR-2020-0272

EGU NO_x Mitigation Strategies Proposed Rule TSD

U.S. Environmental Protection Agency

Office of Air and Radiation

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Introduction:

The analysis presented in this document supports the EPA's proposed Revised CSAPR Update for the 2008 Ozone NAAQS. In developing the proposed Revised CSAPR Update, the EPA considered all NO_x control strategies that are widely in use by EGUs, listed below. This Technical Support Document (TSD) discusses costs, emission reduction potential, and feasibility related to these EGU NO_x emission control strategies. Specifically, this TSD explores three topics: (1) the appropriate representative cost resulting from "widespread" implementation of a particular NO_x emission control technology; (2) the NO_x emission rates widely achievable by "fully operating" emission control equipment; and (3) the time required to implement these EGU NO_x control strategies (e.g., installing and/or restoring an emission control system to full operation or shifting generation to reduce NO_x emissions). These analyses inform the EPA's evaluation of costs and emission reductions in Step 3 of its four step interstate transport framework. These mitigation technology assessments are also central to EPA's electricity system impact estimates, compliance feasibility assessments, and emissions budget determinations for the proposed Revised CSAPR Update Rule.

NO_x control strategies that are widely available for EGUs include:

- Returning to full operation any existing SCRs that have operated at fractional design capability;
- Restarting inactive SCRs and returning them to full operation;
- Restarting inactive SNCRs and/or returning to full operation any SNCRs that have operated at fractional design capability;
- Upgrading combustion controls with newer, more advanced technology (e.g., state-of-the-art low NO_x burners);
- Installing new SCR systems;
- Installing new SNCR systems; and
- Shifting generation (i.e., changing dispatch) from high- to low-emitting or zero-emitting units.

To evaluate the cost for some of these EGU NO_x reduction strategies, the agency used the capital expenses, fixed and variable operation and maintenance costs for installing and fully operating emission controls researched by Sargent & Lundy, a nationally recognized architect/engineering firm with the EGU sector expertise. From this research, EPA has created a publicly available Excel-based tool called the Retrofit Cost Analyzer that implements the cost equations.¹ Application of the Retrofit Cost Analyzer equations to the existing coal-fired fleet can be found in the docket.² EPA also used the Integrated Planning Model (IPM) to analyze power sector response while accounting for electricity market dynamics such as generation shifting.

Cost Estimate for Fully Operating Existing SCR that Already Operate to Some Extent

EPA sought to examine costs for full operation of SCR controls. SCR systems are post-combustion controls that reduce NO_x emissions by reacting the NO_x with a reagent (typically ammonia or urea). The SCR technology utilizes a catalyst to increase the conversion efficiency and produces high conversion of

¹ See <https://www.epa.gov/airmarkets/retrofit-cost-analyzer> for the location of the Excel tool and for the documentation of the underlying equations in Attachment 5-3: SCR Cost Methodology (PDF) and Attachment 5-4: SNCR Cost Methodology (PDF).

² See the file "EGU_SCR_and_SNCR_costs_Revised_CSAPR_Proposal.xlsx" for detailed cost estimates using the Retrofit Cost Analyzer for SCR and SNCR operation and installation.

NO_x. Over time with use, the catalyst will degrade and require replacement. The ammonia or urea reagent is also consumed in the NO_x conversion process. Fully operating an SCR includes maintenance costs, labor, auxiliary power, catalyst, and reagent cost. The chemical reagent (typically ammonia or urea) is a significant portion of the operating cost of these controls.

EPA examined the costs to fully operate an SCR that was already being operated to some extent using the equations within the Retrofit Cost Analyzer. There are variable operations and maintenance (VOM) costs related to the consumption of reagent and degradation of the catalyst as well as fixed operating and maintenance (FOM) costs related to maintaining and operating the equipment to be considered.

EPA examined three of the VOM costs illustrated in the Retrofit Cost Analyzer: reagent, catalyst, and auxiliary power. Depending on circumstances, SCR operators may operate the system while achieving less than “full” removal efficiency by using less reagent, and/or not replacing degraded catalyst which allows the SCR to perform at lower reduction capabilities. Consequently, the EPA finds it reasonable to consider the costs of both additional reagent and catalyst maintenance and replacement in representing the cost of optimizing existing and operating SCR systems. In contrast, based on the Retrofit Cost Analyzer equations, the auxiliary power component of VOM is largely indifferent to the NO_x removal. That is, auxiliary power is indifferent to reagent consumption, catalyst degradation, or NO_x removal rate. Therefore, for units where the SCR is operating, but may not be fully operating, the auxiliary power VOM component has likely been incurred.

In addition, based on the Retrofit Cost Analyzer equations for FOM, units running their SCR systems have incurred the complete set of FOM costs, regardless of reagent consumption, catalyst degradation, or NO_x removal rate. Thus, as was the case for the auxiliary power VOM cost component, the FOM cost component is also not included in the cost estimate to achieve “full” operation for units that are already operating. In conclusion, EPA finds that only the VOM reagent and catalyst replacement costs should be included in cost estimates for optimization of partially operating SCRs.

In an SCR, the chemical reaction consumes approximately 0.57 tons of ammonia or 1 ton of urea reagent for every ton of NO_x removed. During development of the Clean Air Interstate Rule (CAIR) and the original CSAPR, the agency identified a marginal cost of \$500 per ton of NO_x removed (1999\$) with ammonia costing \$190 per ton of ammonia, which equated to \$108 per ton of NO_x removed for the reagent procurement portion of operations. The remaining balance reflected other operating costs. Over the years, reagent commodity prices have changed, affecting the operational cost in relation to reagent procurement. For data on the relationship between reagent price and its associated cost regarding NO_x reduction, see Appendix A: “Historical Anhydrous Ammonia and Urea Costs and their Associated Cost per NO_x ton Removed in a SCR.” These commodities are created in large quantities for use in the agriculture sector. Demand from the power sector for use in pollution controls is small relative to the magnitude used in agriculture. Fluctuations in price are expected and are demonstrated in the pricing data presented in Appendix A. Some of these prices reflect conditions where demand and commodity prices are high. Consequently, the reagent costs used by EPA in this rule are representative. In the cost estimates presented here, EPA uses the cost for urea, which is greater than ammonia costs, to arrive at a conservative estimate. In the CSAPR Update, EPA used the default cost of \$310/ton for a 50% weight solution in Retrofit Cost Analyzer. With the updates to the Retrofit Cost Analyzer, the default costs of the urea reagent also increased to \$350/ton for a 50% weight solution of urea. In this action, EPA conservatively assumed the cost of \$350/ton for a 50% weight solution of urea. Using the Retrofit Cost Analyzer (multiplying the VOM \$/ton cost by the ratio of the VOM cost for urea \$/MWh to the total VOM cost \$/MWh) results in a cost of around \$500/ton of NO_x removed for the reagent cost alone.

EPA also estimated the cost of catalyst replacement and disposal in addition to the costs of reagent. EPA identified the cost for returning a partially operating SCR to full operation applying the Retrofit Cost Analyzer equations for all coal-fired units that operated in 2019 in the United States on a per ton of NO_x removed basis. This assessment covered 223 units.³ EPA was able to identify the costs of individual VOM and FOM cost components, including reagent, catalyst, and auxiliary fans. Some of these expenses, as modeled by the Retrofit Cost Analyzer, vary depending on factors such as unit size, NO_x generated from the combustion process, and reagent utilized. The EPA performed multiple assessments with this tool's parameters to investigate sensitivity relating to cost per ton of NO_x removed. Additionally, the agency conservatively modeled costs with urea, the higher-cost reagent for NO_x mitigation (and the reagent included in the Retrofit Cost Analyzer equations). The key input parameters in the cost equations are the size of the unit, the uncontrolled, or "input", NO_x rate, the NO_x removal efficiency, the type of coal, and the capacity factor.⁴

In the analysis, we assumed these units burned bituminous coal at a 47.6% capacity factor.⁵ We assumed that the SCRs operate with the NO_x removal efficiency needed for them to achieve their third-lowest ozone season NO_x rate over the time-period from 2009-2019.⁶ In this section, where we are assessing the cost to return a partially operating SCR to full operation, we examined only the sum of the VOM reagent and catalyst cost components (from the set of 153 units that had minimum "input" NO_x emission rates of at least 0.2 lb/mmBtu).⁷ EPA ranked the quantified VOM costs for each unit and identified the cost at the 90th percentile level rank, which rounded to \$800 per ton of NO_x removed. EPA also identified the average cost which rounded to \$700 per ton of NO_x removed. EPA selected the 90th percentile value because a substantial portion of units had combined reagent and catalyst costs at or less than this \$800/ton of NO_x removed.

Thus, \$800 per ton NO_x removed represents a reasonable estimate of the cost for operating these post combustion controls based on current market prices and typical operation. For purposes of the IPM modeling, the agency assumes that \$800 per ton of NO_x removed is a broadly available cost point for units that currently are partially operating SCRs to fully operate their NO_x controls.

³ See the file "EGU_SCR_and_SNCR_costs_Revised_CSAPR_Proposal.xlsx" for detailed cost estimates using the Retrofit Cost Analyzer for SCR and SNCR operation and installation.

⁴ For the input NO_x rate, each unit's maximum average ozone season (or non-ozone season) emission rate was examined from the period 2003-2019 (inclusively) for the purpose of identifying the unit's maximum emission rate during time periods when the control was not operating. The long timeframe allowed examination prior to the onset of annual NO_x trading programs (e.g., CAIR and CSAPR). For units where controls have always operated year-round, this method will underestimate the input NO_x rate.

⁵ EPA evaluated costs of SCR operation utilizing a capacity factor value representing recent unit operation. EPA identified the 2019 heat input weighted ozone season capacity factor of 47.6% for 193 coal units with SCR on-line at the start of 2019 and which have nonzero 2019 heat input and are in the CSAPR Update region.

⁶ The NO_x removal efficiency varies by unit and is based on the ozone season or non-ozone season with the highest NO_x rate for the time-period 2003-2019 and is based on the third-lowest ozone season rate from 2009-2019. The third-lowest ozone season rate from 2009-2019 was selected as the "controlled" rate. This was selected because it represented a time when the unit was most likely consistently and efficiently operating its SCR over a time period when the unit would be expected to operate on an annual basis.

⁷ A NO_x emission rate at or above 0.2 lb/mmBtu may be indicative of emissions from units where the SCR is not operating. See the discussion about state-of-the-art combustion controls for details about why 0.2 lb/mmBtu is an appropriate emission rate when only combustion controls are being utilized.

Cost Estimates for Restarting Idled Existing SCR

For a unit with an idled, bypassed, or mothballed SCR, all FOM and VOM costs such as auxiliary fan power, catalyst costs, and additional administrative costs (labor) are realized upon resuming operation through full potential capability. To understand the costs, the agency applied the Retrofit Cost Analyzer equations for two “typical” units with varying input NO_x rates in a bounding analysis and then did a more detailed analysis encompassing all coal-fired units with SCR that operated in 2019 in the contiguous United States. For both analyses, the agency assumed the same input parameters used for the partially-operating SCR analysis described above, but in keeping with this assessment’s focus on restarting SCRs that are not already operating, these analyses included the auxiliary fan power VOM component and all of the FOM components along with the reagent and catalyst VOM components in the total cost estimate.

First, to better understand the effect of input NO_x rate on costs, using the Retrofit Cost Analyzer equations, the EPA performed a bounding analysis to identify reasonable high and low per-ton NO_x control costs from reactivating an existing but idled SCR across a range of potential uncontrolled NO_x rates.⁸ Similar to what was described at proposal, for a hypothetical 500 MW unit with a relatively high uncontrolled NO_x rate (e.g., 0.4 lb NO_x/mmBtu, 80% removal efficiency, 47.6% capacity factor, and 10,000 Btu/kWh heat rate), VOM and FOM costs were around \$1,050/ton of NO_x removed. Conversely, a unit with a low uncontrolled NO_x rate (e.g., 0.2 lb NO_x/mmBtu and 60% removal) experienced a higher cost range revealing VOM and FOM costs about \$1,840/ton of NO_x removed.

Next, using the Retrofit Cost Analyzer cost equations and same input parameters described above for unit-specific input NO_x rate and third best controlled NO_x rate, EPA evaluated all of the VOM and FOM costs for the 153 coal-fired units with SCR in the contiguous United States that were operating in 2019 and had minimum “input” NO_x emission rates of at least 0.2 lb/mmBtu.⁹ As before, EPA ranked the sum of the VOM and FOM costs for each unit and identified the 90th percentile cost. When rounded, this was \$1,600/ton of NO_x removed. EPA also identified the average cost, which rounded to \$1,200/ton of NO_x removed. Specifically, this assessment found that 137 of the 153 units demonstrated VOM plus FOM costs lower than \$1,600/ton of NO_x removed.¹⁰

Examining the results, the EPA concludes that a cost of \$1,600/ton of NO_x removed is reasonably representative of the cost to restart and fully operate idled SCRs.

NO_x Emission Rate Estimates for Full SCR Operation

EPA examined the ozone season average NO_x rates for 250 coal-fired units in the contiguous US with an installed SCR over the time-period 2009-2019, then identified each unit’s lowest, second lowest, and third-lowest ozone season average NO_x rate.¹¹ EPA examined ozone season average NO_x rates over this time period since annual NO_x programs, rather than just seasonal programs, became widespread in the eastern US with the start of CAIR in 2009, and this regulatory development could affect SCR operation

⁸ For these hypothetical cases, the “uncontrolled” NO_x rate includes the effects of existing combustion controls present (i.e., low NO_x burners).

⁹ See the file “EGU_SCR_and_SNCR_costs_Revised_CSAPR_Proposal.xlsx” for detailed cost estimates using the Retrofit Cost Analyzer for SCR and SNCR operation and installation.

¹⁰ Given the sensitivity of the cost to the input uncontrolled NO_x rates, EPA examined the units with higher costs and observed that some exhibited low, uncontrolled NO_x rates suggesting that, perhaps, the SCR may have been consistently operated year-round over the entire time-period. A low uncontrolled NO_x rate would result in a low number of tons of NO_x removed, and, thus, a high cost on a “per ton of NO_x removed” basis when modest fixed and variable costs are divided by just a few tons of NO_x removed.

¹¹ See “SCR_Historical_OS_Rates_Revised_CSAPR_Update_Proposal.xlsx” for details.

(specifically, annual use of SCR means more-frequent change of catalyst and relative difficulty with scheduling timing when the unit (or just the SCR) is not operating to allow for catalyst replacement and SCR maintenance). The final CSAPR Update focused on the third-lowest ozone season NO_x rates, reasoning that these emission rates may be characteristic of a well-run and well-maintained system and achievable on a routine basis, while avoiding atypical times such as the start of a new regulatory program when several catalyst layers may have been simultaneously refreshed or years when the operation of the unit is not similar to recent or expected operational patterns. In the CSAPR Update, EPA focused on the third lowest ozone season rate over the 2009-2015 time period to ensure that the rate represents efficient but routine SCR operation (i.e., the performance of the SCR is not simply the result of being new, or having a highly aggressive catalyst replacement schedule such as may be found at the onset of new emission reduction programs, but is the result of being well-maintained and well-run). At that time, 2015 represented the most recent year of full ozone-season data available. In the CSAPR Update, EPA found that, between 2009 and 2015, EGUs on average achieved a rate of 0.10 lbs NO_x/mmBtu for the third-lowest ozone season rate. In the CSAPR Update, EPA selected 0.10 lbs NO_x/mmBtu as a reasonable representation for full operational capability of an SCR. Here, EPA utilizes the same rationale and methodology for identifying the rate. However, EPA updates the timeline to include most-recent operational data (i.e., up through 2019). Considering the emissions data over the full time-period of available data that includes expected annual operation of SCRs (i.e., 2009-2019) results in a third-best rate of 0.080 lb/mmBtu. EPA notes that half of the EGUs achieved a rate of 0.68 lbs NO_x/mmBtu or less over their third-best entire ozone season (see Figure 1). EPA verified that in prior years, the majority (over 90%) of these same coal-fired units had demonstrated and achieved a NO_x emission rate of 0.08 lb/mmBtu or less on a seasonal and/or monthly basis.¹²

After identifying this approach, the Agency examined each ozone season over the time period from 2009-2019 and identified the lowest monthly average NO_x emission rates for each year. Examining the third-lowest historical monthly NO_x rate, the EPA found that, on average EGUs achieved a rate of 0.069 lbs NO_x/mmBtu. The third-lowest historical monthly NO_x rate analysis showed that a large proportion of units displayed NO_x rates below 0.08 lb/mmBtu (see Figure 2).

Based on the ozone season emission rates, and supported by the monthly rates, the agency concludes an emission rate of 0.08 lb NO_x/mmBtu is widely achievable by the EGU fleet.¹³

Figure 1. “Frequency” distribution plots for coal-fired units with an SCR showing their seasonal average NO_x emission rates (lbs/mmBtu) during ozone seasons from 2009-2019. For each unit, the lowest, second lowest, and third lowest ozone season average NO_x rates are illustrated.

¹² See “Optimizing SCR Units with Best Historical NO_x Rates.xlsx” included in the Docket

¹³ EPA also reviewed historical hourly data and observed reduced capacity factor was not a primary driver of emission rate performance at levels above 20% for SCR controlled coal units in 2019.

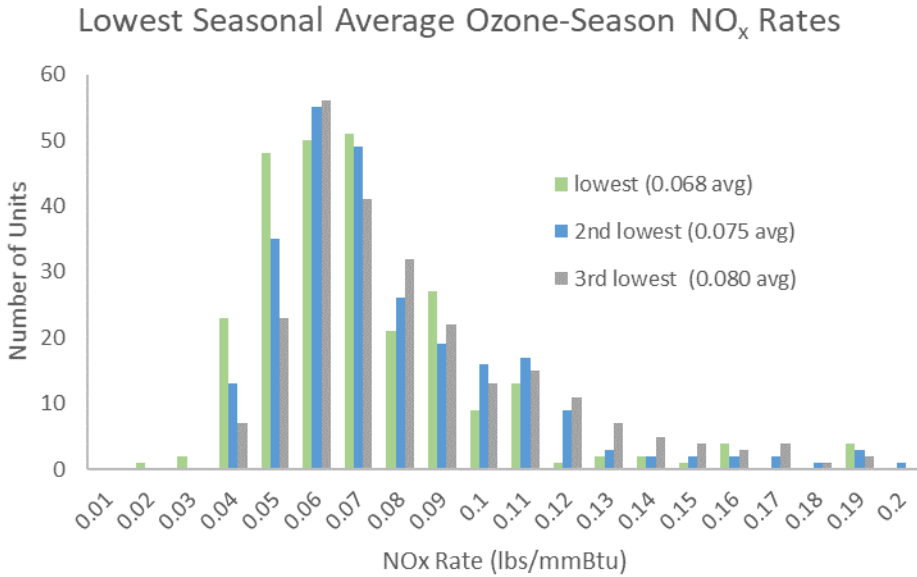
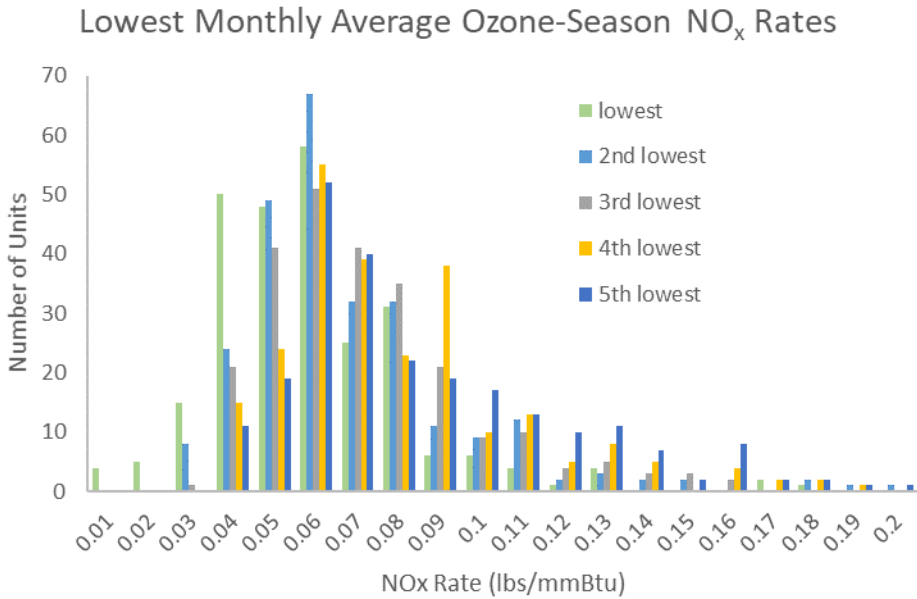


Figure 2. “Frequency” distribution plots for coal-fired units with an SCR showing their monthly average NO_x emission rates (lbs/mmBtu) during ozone seasons from 2009-2019. For each unit, the lowest, second lowest, third lowest, fourth lowest, and fifth lowest monthly average NO_x rates are illustrated.



Cost Estimates for Restarting Idled Existing SNCR

EPA sought to examine costs for full operation of SNCR. SNCR are post-combustion controls that reduce NO_x emissions by reacting the NO_x with either ammonia or urea, without catalyst. Because the reaction occurs without catalyst and is thereby a less efficient reaction, several times more reagent must be injected to achieve a given level of NO_x removal with SNCR than would be required to achieve the

same level of NO_x removal with SCR technology. Usually, an SNCR system does not achieve the level of emission reductions that an SCR can achieve, even when using large amounts of reagent. For the SNCR analysis, as with the SCR analyses described above, the agency used the Retrofit Cost Analyzer equations to perform a bounding analysis for examining operating expenses associated with a “generic” unit returning an SNCR to full operation. For units with a mothballed SNCR returning to full operation, the owner incurs the full suite of VOM and FOM costs. Reagent consumption represents the largest portion of the VOM cost component. For this bounding analysis, the agency examined two cases: first, a unit with a high input uncontrolled NO_x rate 0.40 lb/mmBtu; second, a unit with a low input uncontrolled NO_x rate 0.20 lb /mmBtu – both assuming a 25% removal efficiency.¹⁴ For the high rate unit case, VOM and FOM costs were calculated as approximately \$2,300/ton NO_x with about \$1,820/ton of that cost associated with urea procurement. For the low rate unit case, VOM and FOM costs approached \$3,890/ton NO_x with nearly \$3,040/ton of that cost associated with urea procurement. Despite equivalent reduction percentages for each unit, the cost dichotomy results from differences in the input NO_x rates for the units and the type of boiler, resulting in a modeled step-change difference in urea rate (either a 15% or 25% reagent usage factor). EPA also examined SNCR cost sensitivity by varying NO_x removal efficiency while maintaining the uncontrolled NO_x emission rate. In these studies, SNCR NO_x removal efficiency was assumed to be 40% for the first cost estimate and 10% for the second cost estimate. For a high rate unit with an uncontrolled rate of 0.40 lb NO_x/mmBtu, the associated costs were \$2,210/ton and \$2,600/ton. For a low rate unit with an uncontrolled rate of 0.20 lb NO_x/mmBtu, the associated costs were \$3,730/ton and \$4,4700/ton. This analysis illustrates that SNCR costs (\$/ton) are more sensitive to a unit’s uncontrolled input NO_x rate than the potential NO_x removal efficiency of the SNCR itself. Examining the results across all the simulations, but focusing on the 25% removal efficiency scenario for the low input uncontrolled NO_x rate, which is more representative of typical removal efficiency, EPA finds that costs for fully operating idled SNCR are substantially higher than for SCR. We conclude that a cost of \$3,900/ton of NO_x removed is representative of the cost to restart and fully operate idled SNCRs.

NO_x Emission Rate Estimates for Full SNCR Operation

As EPA notes above, both in the CSAPR Update Rule and in the agency’s power sector modeling up to 25% removal potential for SNCR was assumed. In order to translate what this optimized value would be for each unit, and compare that to 2019 baseline emission rates, EPA utilized the mode 2 rate from the NEEDS database (June 2020). As described in EPA’s power sector IPM Modeling Documentation (Chapter 3), these unit-specific NO_x mode rates are calculated from historical data and reflect operation of existing post-combustion controls.¹⁵ Four modes are identified for each unit to, among other things, identify their emission rates with and without their post-combustion controls operating. Mode 2 for SNCR-controlled coal units is intended to reflect the operation of that unit’s post combustion control based on prior years when that unit operated its control. As noted above, SNCRs are more sensitive to a unit’s uncontrolled input NO_x rate than the potential NO_x removal efficiency. Consequently, the “optimized” SNCR emission rate identified through mode 2 has more variability than the optimized rate

¹⁴ For both cases, we examined a 500 MW unit with a heat rate of 10,000 Btu/kWh operated at a 27.3% annual capacity factor while burning bituminous coal. The 2019 heat input weighted ozone season capacity factor for 44 coal units with SNCR on-line at the start of 2019 and which have nonzero 2019 heat input and are in the CSAPR Update region was 27.3%. Furthermore, in the cost assessment performed here, the agency conservatively assumes SNCR NO_x removal efficiency to be 25%, noting that multiple installations have achieved better results in practice. 25% removal efficiency is the default NO_x removal efficiency value from the IPM documentation. See <https://www.epa.gov/airmarkets/retrofit-cost-analyzer> for the location of the Excel tool and for the documentation of the underlying equations in Attachment 5-4: SNCR Cost Methodology (PDF).

¹⁵ https://www.epa.gov/sites/production/files/2019-03/documents/chapter_3_0.pdf

assumed for SCR installations (which typically begin to approximate an emission rate floor due to the 90% reduction). The optimized SNCR emission rates assumed for each controlled unit are identifiable in the NEEDS file “Mode 2 NO_x rate (lb/mmBtu)” column.¹⁶ If a unit’s 2019 emission rate was at or lower than its “optimized” SNCR rate, than no additional reductions are expected from “optimizing” that unit’s post-combustion control.

Cost Estimates for Installing Low NO_x Burners and / or Over Fire Air

Combustion control technology has existed for many decades. The technology generally limits NO_x formation during the combustion process by extending the combustion zone. Over time, as the technology has advanced, combustion controls have become more efficient at achieving lower NO_x rates than those installed years ago. Modern combustion control technologies routinely achieve rates of 0.20 – 0.25 lb NO_x/mmBtu and, for some units, depending on unit type and fuel combusted, can achieve rates below 0.16 lb NO_x/mmBtu. Table 1 shows average NO_x rates from coal-fired units with various combustion controls for different time periods.

Table 1: Ozone Season NO_x Rate (lb/mmBtu) Over Time for Coal-fired Units with Various Combustion Controls*

NO _x Control Technology	Years Between 2003 and 2008		Years Between 2009 and 2018		Year = 2019	
	NO _x Rate (lb/mmBtu)	Number of Unit- Years	NO _x Rate (lb/mmBtu)	Number of Unit- Years	NO _x Rate (lb/mmBtu)	Number of Unit- Years
<i>Overfire Air</i>	0.384	476	0.294	603	0.221	30
<i>Low NO_x Burner Technology (Dry Bottom only)</i>	0.351	1,062	0.270	1,126	0.209	46
<i>Low NO_x Burner Technology w/ Overfire Air</i>	0.306	464	0.228	672	0.202	41
<i>Low NO_x Burner Technology w/ Closed-coupled OFA</i>	0.266	341	0.223	326	0.187	20
<i>Low NO_x Burner Technology w/ Separated OFA</i>	0.222	451	0.191	584	0.159	33
<i>Low NO_x Burner Technology w/ Closed-coupled/Separated OFA</i>	0.207	460	0.169	773	0.147	59

* Source: Air Markets Program Data (AMPD), ampd.epa.gov, EPA, 2020

Current combustion control technology reduces NO_x formation through a suite of technologies. Whereas earlier generations of combustion controls focused primarily on either Low NO_x Burners (LNB) or Overfire Air (OFA), modern controls employ both, and sometimes include a second, separated overfire air system. Further advancements in fine-tuning the burners and overfire air system(s) as a complete assembly have enabled suppliers to obtain better results than tuning individual components. For this regulation, the agency evaluated EGU NO_x reduction potential based on upgrading units to modern combustion controls. Combustion control upgrade paths are shown in Table 3-11 of the IPM version 6 documentation (*see* Chapters 3 and 5 of the IPM documentation for additional information, and Table 2 below).¹⁷ The fully upgraded configuration for units with wall-fired boilers is LNB with OFA. For units with tangential-fired boilers, the fully upgraded configuration is LNC3 (Low NO_x burners with Close-

¹⁶ See the NEEDS v.6 data file available in the docket and for download at <https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6>

¹⁷ https://www.epa.gov/sites/production/files/2018-08/documents/epa_platform_v6_documentation_-_all_chapters_august_23_2018_updated_table_6-2.pdf

Coupled and Separated Overfire Air). For each unit, EPA's understanding of the current NO_x control configuration can be found in the "NO_x Comb Control" column of the National Electric Energy Data System v6 (NEEDS) database file.¹⁸ EPA identified whether a unit has combustion control upgrade potential by comparing the Mode 1 NO_x Rate (lbs/mmBtu) with the Mode 3 NO_x Rate (lbs/mmBtu) within NEEDS. If the Mode 3 value is lower than the Mode 1 value, then the unit's combustion control configuration does not match the state-of-the-art configuration outlined in Table 2. For these units, EPA assumed a combustion control upgrade is possible based on the technology configurations identified in the NO_x post combustion control column.

With the wide range of LNB configurations and furnace types present in the fleet, the EPA decided to assess compliance costs based on an illustrative unit.¹⁹ The agency selected this illustrative unit because its attributes (e.g., size, input NO_x emission rate) are representative of the EGU fleet, and, thus, the cost estimates are also representative of the EGU fleet. The EPA estimated costs for various combustion control paths. The cost estimates utilized the equations found in Table 5-4 "Cost (2011\$) of NO_x Combustion Controls for Coal Boilers (300 MW Size)" from Chapter 5 of the IPM 5.13 documentation.²⁰ For these paths, EPA found that the cost ranges from \$420 to \$1140 per ton NO_x removed (\$2011). EPA examined slightly lower capacity factors (i.e., 70%) and found the costs increased from \$510 to \$1,370 per ton. At lower capacity factors (i.e., 47.6%), costs increased to a max of \$1,970 per ton for one type of installation.²¹ Examining the estimates for all the simulations, the agency finds that the costs of combustion control upgrades for units operating in a baseload fashion are typically comparable to the costs for returning a unit with an inactive SCR to full operation (i.e., \$1,600/ton). Consequently, EPA identifies \$1,600/ton as the cost level where upgrades of combustion controls would be widely available and cost-effective.

NO_x Emission Rate Estimates for LNB upgrade

EPA first identified the current boiler type of a given unit, and then applied the information shown below in Table 2 regarding state-of-the-art configurations compared to a unit's reported combustion control configuration to determine whether the unit had combustion control upgrade potential. If so, then EPA assumed the combustion control upgrade configuration would yield an emission rate of 0.1549 lb/mmBtu for dry-bottom wall fired boilers that were upgrading their combustion controls. EPA assumed a rate of 0.1390 lb/mmBtu for tangentially-fired coal boilers that were upgrading their controls. These estimates were derived from an assessment of historical data where EPA reviewed similar boiler configurations with fully upgraded combustion controls and their resulting emission rates. Specifically, EPA examined two types of coal steam units – dry bottom wall-fired boilers and tangentially fired boilers – with state-of-

¹⁸ See the NEEDS v.6 data file available in the docket and for download at <https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6>

¹⁹ For this analysis, EPA assumed a 500 MW unit with a heat rate of 10,000 Btu/kWh and an 85% annual capacity factor. We assumed the unit was burning bituminous coal and had an input uncontrolled NO_x rate of 0.50 lb NO_x / mmBtu initial rate and had a 42% NO_x removal efficiency after the combustion control upgrades. This 0.50 lbs/mmBtu input NO_x rate is comparable to the observed average rate of 0.48 lbs/mmBtu for the coal-fired wall-fired units from 2003-2008 that had not installed controls. There are very few remaining units that lack combustion controls. One unit had a rate higher than 0.5 lb/mmBtu. Using 2019 data for uncontrolled wall-fired coal units and comparing these rates against controlled units of the same type, EPA observes a 42% difference in rate. Similarly, EPA observes a 55% reduction for coal units with tangentially-fired boilers. Despite the very small numbers of remaining uncontrolled units, to be conservative, EPA used the 42% reduction from wall-fired coal units.

²⁰ https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_emission_control_technologies_0.pdf

²¹ When EPA analyzed low capacity factor/low emission rate scenarios down to capacity factors of 47% and emission rates of 0.30 lb/mmBtu, the range of costs increased from \$1,260 to \$3,280.

the-art combustion controls (SOA CC). EPA estimated the average 2016 ozone season NO_x emission rates for all such units by firing type. For dry bottom wall-fired coal boilers with “Low NO_x Burner” and “Overfire”, there were 148 units averaging 0.1549 lb/mmBtu. For tangentially-fired coal boilers with “Low NO_x Burner” and “Closed-coupled/Separated OFA”, there were 105 units averaging 0.1390 lb/mmBtu.

Table 2: State-of-the-Art Combustion Control Configurations by Boiler Type

Boiler Type	Existing NO_x Combustion Control	Incremental Combustion Control Necessary to Achieve “State-of-the-Art”
Tangential Firing	Does not Include LNC1 and LNC2	LNC3
	Includes LNC1, but not LNC2	CONVERSION FROM LNC1 TO LNC3
	Includes LNC2, but not LNC3	CONVERSION FROM LNC2 TO LNC3
	Includes LNC1 and LNC2 or LNC3	-
Wall Firing, Dry Bottom	Does not Include LNB and OFA	LNB + OFA
	Includes LNB, but not OFA	OFA
	Includes OFA, but not LNB	LNB
	Includes both LNB and OFA	-

Note: Low LNB =NO_x Burner Technology, LNC1=Low NO_x coal-and-air nozzles with close-coupled overfire air, LNC2= Low NO_x Coal-and-Air Nozzles with Separated Overfire Air, LNC3 = Low NO_x Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air, OFA = Overfire Air

Cost and Emission Rate Performance Estimates for Retrofitting with SNCR and Related Costs

SNCR technology is an alternative method of NO_x emission control that incurs a lower capital cost compared with an SCR, albeit at the expense of greater operating costs and less NO_x emission reduction. Some units with anticipated shorter operational lives or with low utilization may benefit from this control technology. The higher cost per ton of NO_x removed reflects this technology’s lower removal efficiency which necessitates greater reagent consumption, thereby escalating VOM costs. The agency examined the costs of retrofitting a unit with SNCR technology using the Retrofit Cost Analyzer. The agency conservatively set the NO_x emission reduction rate at 25% – the same assumption used in the CSAPR Update Rule and in EPA’s power sector modeling. For the unit examined above (500 MW, 0.2 lbs NO_x/mmBtu) with a 47.6% capacity factor, the cost is \$6,680/ton of NO_x removed. When the capacity factor is 27.3%, the costs increase to \$9,000/ton. At higher capacity factors (e.g., 70% and 85%), the costs decrease, going to \$5,680 and \$5,310/ton, respectively.

Next, EPA examined the remaining coal-fired fleet that lack SNCR or other NO_x post-combustion control to estimate a median cost of SNCR installation (on a \$/ton basis). Costs were estimated for units that had a minimum input NO_x rate of at least 0.2 lb/mmBtu and an assumed NO_x removal rate of 25%, assumed to use bituminous coal, assumed annual operation of the control, and an assumed capacity factor of 59.3%

(the fleet-wide coal capacity factor from the January 2020 IPM reference case).²² In this instance, the median value is \$5,800/ton.²³

Cost and Emission Rate Performance Estimates for Retrofitting with SCR and Related Costs

For coal-fired units, an SCR retrofit is the state-of-the-art technology used to achieve the greatest reductions in NO_x emissions. The agency examined the cost for newly retrofitting a unit with SCR technology. EPA conservatively assumed 0.07 lb/mmBtu emission rate performance for a new state-of-the-art SCR retrofit. The same assumption used in the CSAPR Update Rule and in EPA's power sector modeling along with the Retrofit Cost Analyzer.²⁴ Historically, reported unit-level emission rate data further supports this assumption, as many of the recently installed SCRs achieve this emission rate or lower on a yearly basis.

First, to better understand the effect of input NO_x rate on costs, using the Retrofit Cost Analyzer equations, the EPA performed a bounding analysis to identify reasonable high and low per-ton NO_x control costs for adding SCR post-combustion controls across a range of potential uncontrolled NO_x rates.²⁵ For a hypothetical unit 500 MW in size with a relatively low uncontrolled NO_x rate (e.g., 0.2 lb NO_x/mmBtu, 60% removal efficiency, 47.6% capacity factor, and 10,000 Btu/kWh heat rate), the capital cost was about \$143,000,000. For a similar unit with an input NO_x rate of 0.4 lb/mmBtu and 80% NO_x removal efficiency, the total capital cost was \$152,000,000. The cost on a per-ton basis varies with the assumptions concerning the operation of the unit and the book life of the loan (or lifetime of the equipment). Assuming an annual capital recovery factor of 0.143, NO_x rate of 0.2 lb/mmBtu and removal efficiency of 60% and annual operation, the cost per ton was \$18,210/ton (\$16,373/ton for the capital cost, \$290/ton for the FOM cost, and \$1,546/ton for the VOM cost). For the unit with the NO_x rate of 0.4 and removal efficiency of 80%, the costs were \$7,562/ton (\$6,515/ton for the capital cost, \$115/ton for the FOM cost, and \$932/ton for the VOM cost).

In CSAPR Update, using a higher capacity factor assumption, EPA used the Retrofit Cost Analyzer to examine the costs of SCR retrofit for an illustrative unit, a 500 MW unit operating at an 85% capacity factor with an uncontrolled rate of 0.35 lb NO_x / mmBtu, retrofitted with an SCR to a lower emission rate of 0.07 lb NO_x / mmBtu, results in a compliance cost of \$5,000 / ton of NO_x removed. For this illustrative unit, as annual capacity factor increased, costs per ton decreased (because the capital cost is constant, but the number of tons of emissions decreases).

For this proposal, EPA examined the remaining coal-fired fleet that lack SCR to estimate a median cost of SCR installation (on a \$/ton basis). Costs were estimated for units that had uncontrolled NO_x rates of at least 0.2 lb/mmBtu prior to installation of the post-combustion control and decreasing to rates of 0.07

²² For the input NO_x rate for units with SNCR NO_x post-combustion controls that could presumably upgrade to SCR post-combustion control technology, each unit's maximum average ozone season (or non-ozone season) emission rate was examined from the period 2003-2019 (inclusively) for the purpose of identifying the unit's maximum emission rate during time periods when the control was not operating. The long timeframe allowed examination prior to the onset of annual NO_x trading programs (e.g., CAIR and CSAPR). For units where controls have always operated year-round, this method will underestimate the input NO_x rate. For the input NO_x rate for units that lack SNCR post-combustion controls, we used the most recent available ozone-season average NO_x rate (i.e., 2019).

²³ See the file "EGU_SCR_and_SNCR_costs_Revised_CSAPR_Proposal.xlsx" for detailed cost estimates using the Retrofit Cost Analyzer for SCR and SNCR operation and installation.

²⁴ https://www.epa.gov/sites/production/files/2019-03/documents/chapter_5.pdf

²⁵ For these hypothetical cases, the "uncontrolled" NO_x rate includes the effects of existing combustion controls present (i.e., low NO_x burners).

lb/mmBtu following control installation and were assumed to use bituminous coal.²⁶ Furthermore, we assumed annual operation of the control and assumed a capacity factor of 59.3% (the capacity factor for coal units from the January 2020 IPM v.6 reference case). In this instance, we get a median value of \$9,600/ton and a 90th percentile value of \$13,700/ton. For a typical baseload coal capacity factor of 80%, the 90th percentile is less than the \$9,600/ton value.²²⁷

Feasibility Assessment: Implementation Timing for Each EGU NO_x Control Strategy

The agency evaluated the implementation time required for each compliance option to assess the feasibility of achieving reductions during the 2021 ozone season.

EPA evaluated the feasibility of turning on idled SCRs for the 2021 ozone season. The EGU sector is very familiar with restarting SCR systems. Based on past practice and the possible effort to restart the controls (e.g., re-stocking reagent, bringing the system out of protective lay-up, performing inspections), returning these idled controls to operation is possible within the compliance timeframe of this rule. This timeframe is informed by many electric utilities' previous, long-standing practice of utilizing SCRs to reduce EGU NO_x emissions during the ozone season while putting the systems into protective lay-up during non-ozone season months when the EGUs did not have NO_x emission limits that warranted operation of these controls. For example, this was the long-standing practice of many EGUs that used SCR systems for compliance with the NO_x Budget Trading Program. Based on the seasonality of EGU NO_x emission limits, it was typical for EGUs to turn off their SCRs following the September 30 end of the ozone season control period. They would then lay-up the pollution control for seven months of non-use. By May 1 of the following ozone season, the control would be returned to operation. In the 22 state CSAPR Update region, 2005 EGU NO_x emission data suggest that 112 EGUs operated SCR systems in the summer ozone season, likely for compliance with the NO_x Budget Trading program, while idling these controls for the remaining seven non-ozone season months of the year.²⁸ In order to comply with the seasonal NO_x limits, these SCR controls regularly were taken out of and put back into service within seven months. Therefore, EPA believes this SCR optimization mitigation strategy is available for the 2021 ozone season.

EPA assessed the number of coal-fired units with SCR that are currently operating with ozone-season emission rates greater than or equal to 0.2 lb/mmBtu suggesting that their units may not be operating their NO_x post-combustion control equipment. EPA finds that only 14 units in the contiguous United States (of which eight are in states that are "linked" at or above 1% in this Revised CSAPR Update Rule) fit this

²⁶ For the input NO_x rate for units with SNCR NO_x post-combustion controls that could presumably upgrade to SCR post-combustion control technology, each unit's maximum average ozone season (or non-ozone season) emission rate was examined from the period 2003-2019 (inclusively) for the purpose of identifying the unit's maximum emission rate during time periods when the control was not operating. The long timeframe allowed examination prior to the onset of annual NO_x trading programs (e.g., CAIR and CSAPR). For units where controls have always operated year-round, this method will underestimate the input NO_x rate. For the input NO_x rate for units that lack SNCR post-combustion controls, we used the most-recent available ozone-season average NO_x rate (i.e., 2019).

²⁷ See the file "EGU_SCR_and_SNCR_costs_Revised_CSAPR_Proposal.xlsx" for detailed cost estimates using the Retrofit Cost Analyzer for SCR and SNCR operation and installation.

²⁸ Units with SCR were identified as those with 2005 ozone season average NO_x rates that were less than 0.12 lbs/mmBtu and 2005 average non-ozone season NO_x emission rates that exceeded 0.2 lb/mmBtu.

criterion.²⁹ EPA's assumptions that this mitigation technology is available for the 2021 ozone-season is further bolstered given that the previous rulemaking (i.e., CSAPR Update) identified turning on and operating existing SCR as a cost-effective control technology, many sources successfully implemented that technology requirement, and it appears that only a low number of units in the region may have turned off these controls.

Full operation of existing SCRs that are already operating to some extent involves increasing reagent (i.e., ammonia or urea) flow rate, and maintaining and replacing catalyst to sustain higher NO_x removal rate operations. As with restarting idled SCR systems, EGU data demonstrate that operators have the capability to fully idle SCR systems during winter months and return these units to operation in the summer to comply with ozone season NO_x limits.²⁸ The EPA believes that this widely demonstrated behavior also supports our finding that fully operating existing SCR systems currently being operated, which would necessitate fewer changes to SCR operation relative to restarting idled systems, is also feasible for the 2021 ozone season. Increasing NO_x removal by SCR controls that are already operating can be implemented by procuring more reagent and catalyst. EGUs with SCR routinely procure reagent and catalyst as part of ongoing operation and maintenance of the SCR system. In many cases, where the EPA has identified EGUs that are operating their SCR at non-optimized NO_x removal efficiencies, EGU data indicate that these units historically have achieved more efficient NO_x removal rates. Therefore, the EPA finds that optimizing existing and SCR systems currently being operated could generally be done by reverting to previous operation and maintenance plans. Regarding full operation activities, existing SCRs that are only operating at partial capacity still provide functioning, maintained systems that may only require increased chemical reagent feed rate up to their design potential and catalyst maintenance for mitigating NO_x emissions. Units must have adequate inventory of chemical reagent and catalyst deliveries to sustain operations. Considering that units have procurement programs in place for operating SCR, this may only require updating the frequency of deliveries. This may be accomplished within a few weeks. The vast majority of existing units with SCRs covered in this action fall into this category.

Combustion controls, such as LNB and/or OFA, represent mature technologies requiring a short installation time – typically, four weeks to install along with a scheduled outage (with order placement, fabrication, and delivery occurring beforehand and taking a few months). Construction time for installing combustion controls was examined by the EPA during the original CSAPR development and is discussed in the TSD for that rulemaking entitled, “Installation Timing for Low NO_x Burners (LNB)”, Docket ID No. EPA-HQ-OAR-2009-0491-0051.³⁰ Industry has demonstrated retrofitting LNB technology controls on a large unit (800 MW) in under six months. This TSD is in the docket for the CSAPR Update and for this rulemaking. EPA is providing until 2022 to implement these controls as the limited time available between the estimated signature date of this rule and start of the 2021 ozone season would not be sufficient to install LNBs on a regional level.

This rule does not consider retrofitting SCR or SNCR technology as a viable compliance option in the 2021 compliance timeframe. The time requirements for a single boiler SCR retrofit exceed 18 months from contract award through commissioning (not including permitting). SNCR is similar to activated

²⁹ See the “2019 NO_x Rates for 258 Units.xlsx file” in the docket for details. Eight of the units are in states linked at or above 1%. Three are in Ohio, two each are in Kentucky and New York, and one is in Indiana. Both units in New York have since permanently retired; Somerset 1 last operated in March 2020 and Cayuga 1 last operated in August 2019. Both units in Kentucky have since permanently retired; Paradise 3 last operated in February 2020 and Elmer Smith 1 last operated in June 2019.

³⁰ http://www.epa.gov/airmarkets/airtransport/CSAPR/pdfs/TSD_Installation_timing_for_LNBs_07-6-10.pdf

carbon injection (ACI) and dry sorbent injection (DSI) installation and requires about 12 months from award through commissioning (not including permitting) at a single boiler. Conceptual design, permitting, financing, and bid review require additional time. A detailed analysis for a single SCR system can be found in Exhibit A-3 and an ACI system (equivalent timeline to a SNCR) in Exhibit A-5 in: “Final Report: Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies” located in the Docket for this Rulemaking.³¹ On a regional scale, the estimate for installing SCR at multiple boilers on multiple plants is in excess of 39 months. EPA assumes these technologies would not be available at regional scale prior to the start of the of the 2025 ozone season. See preamble section VII.C for more discussion on post combustion control retrofit timing.

This proposed rule, like prior interstate transport rules, takes into account the potential for shifting generation among electric power producers, depending on the price-signal of the allowances in a trading program. Shifting generation to lower NO_x-emitting or zero-emitting EGUs occurs in response to economic factors, including the costs of pollution control. As the cost of emitting NO_x increases, combined with all other costs of generation, it becomes increasingly cost-effective for units with lower NO_x rates to increase generation, while units with higher NO_x rates reduce generation. Because the cost of generation is unit-specific, this generation shifting occurs incrementally on a continuum. Consequently, there is more generation shifting at higher cost NO_x levels. Because we have identified discrete cost thresholds resulting from the full operation of particular types of emission controls, it is reasonable to simultaneously quantify the reduction potential from generation shifting strategy associated with operating controls at each cost level. Including these reductions is important, ensuring that cost-effective full operation of controls can be expected to occur.

As described in the preamble, EPA modeled generation shifting to units with lower NO_x emission rates only within the same state as a proxy for estimating the amount of generation that could be shifted in the near-term (i.e., 2021). We further assume that such generation shifting only occurs within and among generators that are already in operation and connected to the grid in EPA’s baseline. Under these circumstances, shifting generation to lower NO_x- or zero-emitting EGUs, similar to operating existing post-combustion controls, uses investments that have already been made, and can significantly reduce EGU NO_x emissions relatively quickly. For example, natural gas combined cycle (NGCC) facilities can achieve NO_x emission rates of 0.0095 lb/mmBtu, compared to existing coal steam facilities, which emitted at an average rate of 0.12 lb/mmBtu of NO_x across the 22 states included in the CSAPR Update in 2019. Similarly, generation could shift from uncontrolled coal units to SCR-controlled or SNCR controlled coal units. Shifting generation to lower NO_x-emitting EGUs would be a cost-effective, timely, and readily available approach for EGUs to reduce NO_x emissions, and EPA analyzed EGU NO_x reduction potential from this control strategy for the CSAPR Update. EPA considers that the amount of generation shifting modeled to occur within each particular linked state in response to the selected control strategy represented by \$1600/ton reflects the generation shifting that can occur in the 2021 ozone season and is thus incorporated into the emission budgets. Table 3 and Table 4 below illustrate the low amount of generation assumed in EPA’s analysis relative to historical levels.

<p>Table 3: Regional Coal and Gas Summer Generation Changes Base to Cost Threshold Case (2021, GWh)</p>
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³¹ <http://nepis.epa.gov/Adobe/PDF/P1001G00.pdf>

Region	Coal Adj. Base Case	Coal (\$1600/ton)	Coal Change	Coal Percent Change	Combined Cycle Adj. Base Case	Combined Cycle (\$1600/ton)	Combined Cycle Change	Combined Cycle Percent Change
MISO	104,670	101,791	-2,879	-2.8%	82,672	85,044	2,372	2.9%
NY	7	7	0	0.0%	29,193	29,205	12	0.04%
PJM	72,435	71,393	-1,041	-1.4%	138,672	140,267	1,595	1.2%
SERC	62,963	62,797	-166	-0.3%	120,689	120,779	90	0.1%

Table 4: Historical Rate of Generation Change for Coal and Combined Cycle Units

	Coal Generation (GWh)					Combined Cycle Generation (GWh)				
	2016	2017	2018	2019	Average annual change	2016	2017	2018	2019	Average annual change
Total for 12 linked states	235,218	211,145	206,053	167,880	10.39%	132,404	131,081	149,124	179,518	-11.05%

Additional Mitigation Technologies Assessed but Not Proposed in this Action

Mitigation Strategies at Small Units that Operate on High Electricity Demand Days (HEDD).

In previous rules, stakeholders have commented that emissions on the days that are conducive to ozone matter the most for attainment of the NAAQS. The seasonal trading programs have been highly effective, ensuring that the large units install and operate efficient post-combustion controls. However, the days that are conducive to ozone in the summer tend to have high temperatures, and as a result, are associated with substantial additional electricity demand from air conditioning (among other reasons). To meet this incremental demand, particularly in some areas where there are noted transmission constraints, small units that have relatively high emission rates initiate operation. These units are often simple cycle combustion turbines or oil-fired boilers. They are usually small and only operate a few hours out of the summer. The generation they provide is likely critical to ensuring grid stability during these high-demand times. Having sufficient generation available to meet demand is essential for health and safety. At the same time, emissions from these sources can help cause or exacerbate exceedances of the NAAQS.

In the 12 states affected by the CSAPR Update Revision, EPA identified a total of 1,096 units that operated during the 2019 ozone season. Of these, 102 units exhibited capacity factors that fell below 10% for the period. The majority of these units (94 out of 102) were combustion turbine units—29 of which were fueled by oil and 65 were fueled by natural gas. While the 102 identified units, called “peaker units” here, operated in relatively few hours during the 2019 ozone season, an average of 13% of gross generation from these units occurred in higher energy demand hours, which we define as the top 1% of hours with the highest regional electric load. For 18 of these units, electricity production in higher energy demand hours accounted for at least 20% of their total generation for the 2019 ozone season.

With their relatively high emission rates, relatively small seasonal capacity factors, and tendency to operate on HEDD, the emissions could have substantial emissions and air quality impacts on high ozone days. An assessment of emissions intensities for the units relative to the state and regional average emission rate indicates that the emission rates of these units can be up to 118 times their respective state averages. In the 12-state region, 50 units across 17 facilities had emission intensity values substantially higher than the state average. Dividing the unit-level 2019 ozone season NO_x rate by the average 2019 ozone season NO_x rate for the state, indicated that the emission rates for these units were at least 20 times that of their respective state averages for the 2019 ozone season.

In a separate analysis, EPA identified six states located in the northeastern US in which significant air quality problems may persist on HEDD—Pennsylvania, New Jersey, New York, Delaware, Connecticut, and Maryland. For a better understanding of the emissions impact of combustion turbine unit operations, we compared the peak hour generation and emissions activities of natural gas and oil units located in these states on sample HEDD and low energy demand days (LEDD). The sample days were chosen from a selection of 15 days in the 2019 ozone season with the highest and lowest cumulative daily gross load for all EGUs in CAMD in the six states. The exemplary HEDD and LEDD days and peak hours used in the analysis are July 30, 16:00, and May 18, 18:00, respectively.

When comparing gross generation between the two days, we observe that combustion turbine natural gas and oil units generate more in days and hours of higher energy demand. On the exemplary LEDD, combustion turbine natural gas and oil units in the six northeastern states provided a total of 3,953 MWh of electricity over the course of the day—673 MWh of which was produced in the peak hour (Figure 3), contributing to 539 lbs, or 9% of the total peak hour NO_x emissions in the six states (Figure 4). Comparatively, on the HEDD, gross generation from combustion turbine units amounted to 28,263 MWh over the course of the day. Generation in the peak hour reached 2,207 MWh (Figure 3), and contributed to 4,881 lbs, or 19% of total peak hour NO_x emissions (Figure 5).

For the example HEDD day, the largest shares of peak hour NO_x emissions from combustion cycle units originate in New York and Pennsylvania (Figure 5). A unit-level assessment of peakers in New York state indicates that while these units are highly emissions-intensive, they provide relatively minimal generation in peak hours. Specifically, combustion cycle natural gas and oil units in New York contribute to 1,359 lbs, or 19%, of the state's total peak hour NO_x emissions on the sample HEDD, while only providing 1,186 MWh, or 8%, of generation. On this sample HEDD, the Glenwood and Holtsville facilities, in particular, account for 4% of total peak hour oil generation in New York but contribute to 31% of the total peak hour NO_x emissions from oil units (Figure 6). With peak hour NO_x rates of 0.44 lb/mmBtu and 0.58 lb/mmBtu, respectively, the Glenwood and Holtsville facilities are relatively emissions intensive; however, these units only dispatch in hours and days with higher energy demand. In 2019, Glenwood operated a total of 31 hours, 19 of which fell in the ozone season, while Holtsville ran a total of 403 hours. Of these, 222 hours fell in the ozone season.

Increasingly, states have focused on regulation of these sources, tightening emissions standards for them (see NJ regs and NY regs). For example, in January of 2020 the New York Department of Environmental Conservation (NY-DEC) adopted a rule to limit emissions from combustion turbines that operate as peaking units. New York's adopted Subpart 227-3³², entitled "Ozone Season NO_x Emission Limits for Simple Cycle and Regenerative Combustion Turbines." The regulation applies to simple cycle

³² Subpart 227-3 is found within Chapter III, Air Resources, Part 227, of Title 6 of New York Codes, Rules and Regulations (NYCRR).

combustion turbines (SCCTs) with a nameplate capacity of 15 MW or greater that supply electricity to the grid. The regulation contains two compliance dates with increasingly stringent NO_x limits, as follows: by May 1, 2023, all SCCTs subject to the rule must meet a NO_x emission limit of 100 ppmvd³³, and; by May 1, 2025, gas-fired SCCTs must meet a NO_x emission limit of 25 ppmvd, and distillate or other liquid-fueled units must a limit of 42 ppmvd. In lieu of meeting these limits directly, New York's rule offers two alternative compliance options. The first compliance option allows owners and operators to elect an operating permit condition that would prohibit the source from operating during the ozone season. The second option allows owners and operators to adhere to an output-based NO_x daily emission rate that includes electric storage and renewable energy under common control with the SCCTs with which they would be allowed to average.

The EPA previously promulgated NO_x emission standards for combustion turbines, which are found in New Source Performance Standards (NSPS) located at 40 CFR Part 60, Subparts GG and KKKK. Subpart GG covers turbine engines that commenced constructed after October 3, 1977 and before February 18, 2005. Subpart KKKK covers both the combustion turbine engine and any associated heat recovery steam generator for units that commenced construction after February 18, 2005. SO₂ emission limits are also contained within these requirements. Several states within the Ozone Transport Region (OTR) have adopted NO_x emission limits for combustion turbines.

³³ Parts per million on a dry volume basis at 15% oxygen.

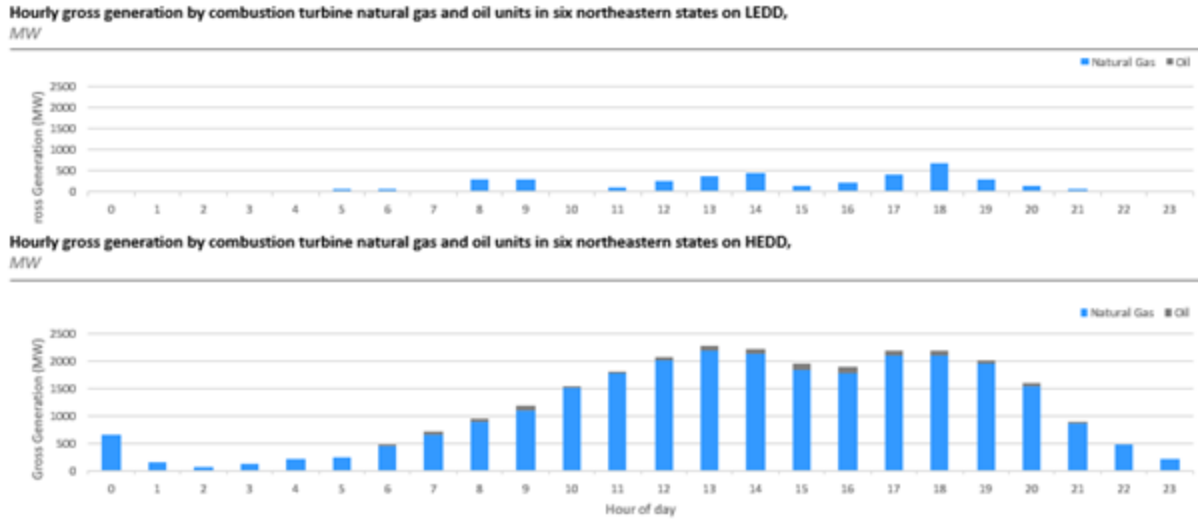
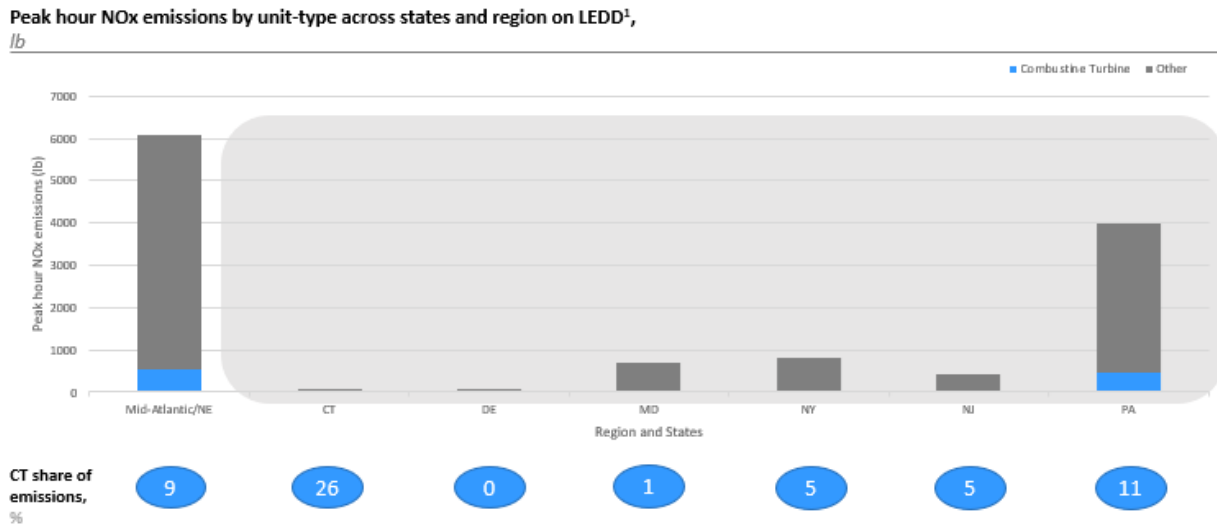


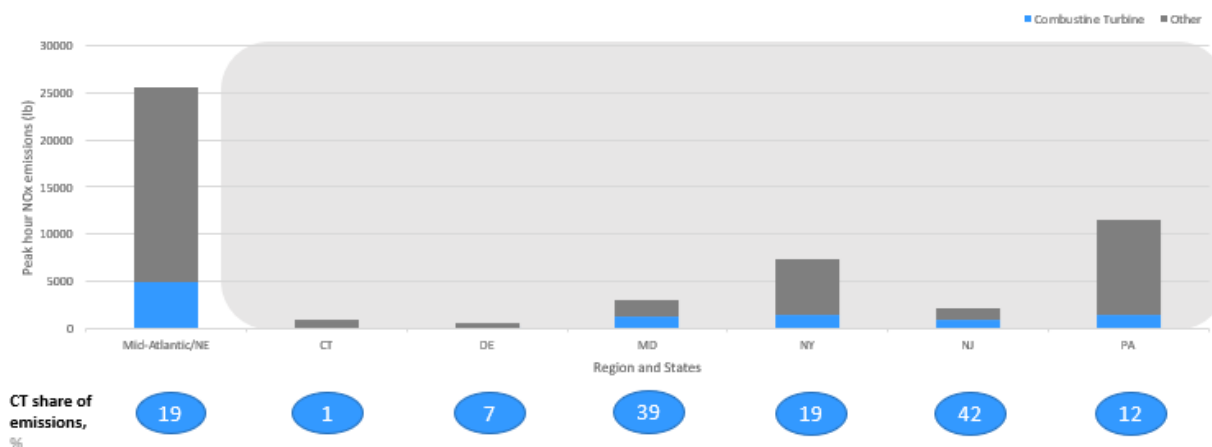
Figure 3. Hourly gross generation by combustion turbine natural gas and oil units in the six northeastern states on an exemplary LEDD and HEDD



1) May 18th (18:00) is used as the exemplary LEDD day and peak hour.

Figure 4. Percentage share of peak hour NOx emissions by unit type across region and states on an exemplary LEDD

Peak hour NOx emissions by unit-type across states and region on HEDD¹,
lb



1) July 30th (16:00) is used as the exemplary HEDD day and peak hour.

Figure 5. Percentage share of peak hour NOx emissions by unit type across region and states on an exemplary HEDD (Source: Air Markets Program Data (AMPD), ampd.epa.gov, EPA, 2020)

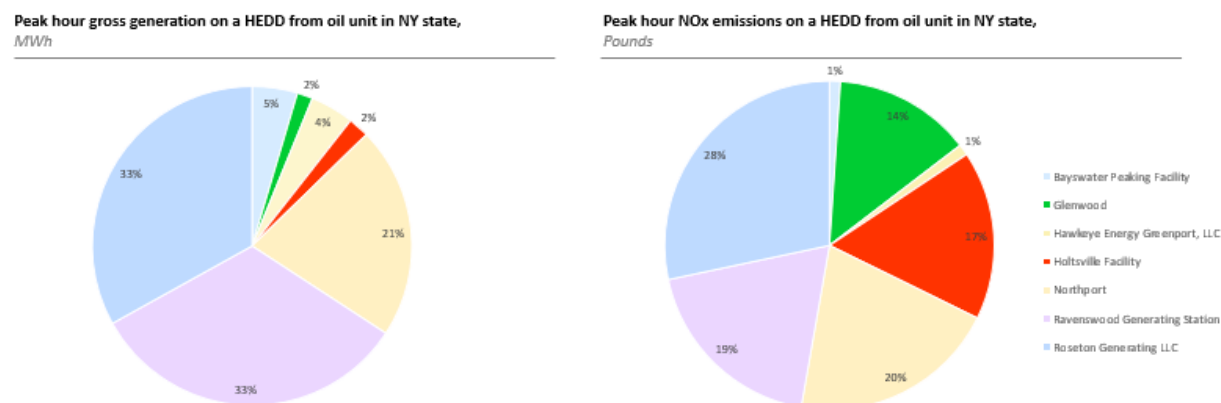


Figure 6. Peak hour generation and emissions on HEDD by oil units in NY as a percentage (Source: Air Markets Program Data (AMPD), ampd.epa.gov, EPA, 2020)

Mitigation Strategies at Small Municipal Solid Waste (MSW) Units

EPA is also inviting comment on whether other EGUs not covered by the existing CSAPR programs should be considered. Stakeholders have pointed out that grid-connected Municipal Solid Waste combustors (MSW) are often located near problematic receptors and have high emission rates. Due to their small size (less than 25 MW) and non-electric load driven operation decisions, EPA has not typically considered these units to be viable sources for cost-effective reductions under the CSAPR framework and therefore excluded them from its regional programs. However, EPA does include their emissions estimates in its EGU inventory and invites comment in the preamble on their relevance and emission reduction potential in an interstate transport rulemaking context going forward.

As additional background, data from EPA’s 2017 National Emissions Inventory (NEI) database reports NOx emissions of 15,758 tons from MWCs in the eleven states that EPA’s modeling indicates significantly contribute to ozone levels in the NY-NJ-CT nonattainment area. EPA regulates emissions of

nine pollutants, including NOx, under Section 111 of the CAA for four types of solid waste incineration units, including MSWs. These requirements are contained within new source performance standards (NSPS) and emission guidelines promulgated by states pursuant to requirements codified within 40 CFR Part 60. Additionally, some states have adopted more restrictive NOx emission limits, primarily through requirements adopted to meet reasonably available control technology (RACT) requirements. Information assembled by the Ozone Transport Commission (OTC) indicates that SNCR is a common control equipment choice for MSW units, as all 9 of the OTC states with MSW units contain at least one facility that controls NOx emissions using that technology.³⁴ Connecticut and New Jersey have adopted the following NOx emission limits, which are among the most restrictive NOx emission limits for MSWs adopted via state requirements: Connecticut has adopted a NOx emission limit of 150 ppm for mass burn waterwall units, and a limit of 146 ppm for processed-municipal solid waste combustors,³⁵ and New Jersey has adopted a NOx emission limit of 150 ppm applicable to MSW units of any size.³⁶ Table 3 below illustrates the projected share of state-level ozone-season NOx EGU emissions expected to come from MSW units in 2023.

Table 5: IPM Projected 2023 OS NOx Emissions (1000 tons) ³⁷				
	MSW	All EGU Sources	MSW Share of Emissions	MSW Emission Rate (lb/mmBtu)
California	0.26	2.37	11%	0.18
Connecticut	1.46	1.94	76%	0.34
Florida	5.05	17.14	29%	0.43
Indiana	0.01	17.82	0%	0.39
Maine	0.47	1.05	44%	0.40
Maryland	1.51	2.83	53%	0.54
Massachusetts	1.76	2.54	69%	0.26
Michigan	0.27	13.96	2%	0.30
Minnesota	0.64	7.97	8%	0.38
New Hampshire	0.12	0.30	42%	0.32
New Jersey	0.95	2.55	37%	0.22
New York	3.43	7.29	47%	0.49
Oregon	0.18	0.69	25%	0.50
Pennsylvania	2.45	13.61	18%	0.40
Virginia	1.01	4.31	24%	0.29
Washington	0.22	0.51	44%	0.38

³⁴ See “White Paper on Control Technologies and OTC State Regulations for Nitrogen Oxide (NOx) Emissions from Eight Source Categories”, Final Draft, February 10, 2017.

³⁵ See Table 38-2a within Section 22a-174-38, Municipal Waste Combustors, of the Regulations of Connecticut State Agencies. Emission limits expressed as ppm are corrected to 7% oxygen, dry basis.

³⁶ See Section 7:27-19.12, Municipal Solid Waste (MSW) Incinerators, of the New Jersey State Department of Environmental Protection Administrative Code.

³⁷ EPA January 2020 IPM Reference Case v6; 2023 Parsed File. Available at <https://www.epa.gov/airmarkets/results-using-epas-power-sector-modeling-platform-v6-january-2020-reference-case>

Appendix A: Historical Anhydrous Ammonia and Urea Costs and their Associated Cost per NO_x ton Removed in a SCR

Minimum Cost to Operate

Anhydrous NH₃ & Urea costs (\$/ton) [from USDA]				
year	NH₃ (anh)	Cost / ton NO_x	Urea cost	Cost / ton NO_x
2009	\$ 562	\$ 320	\$ 425	\$ 425
2010	\$ 548	\$ 312	\$ 424	\$ 424
2011	\$ 801	\$ 457	\$ 543	\$ 543
2012	\$ 808	\$ 461	\$ 746	\$ 746
2013	\$ 866	\$ 494	\$ 508	\$ 508
2014	\$ 739	\$ 421	\$ 533	\$ 533
2015	\$ 729	\$ 416	\$ 472	\$ 472
2016	\$ 588	\$ 335	\$ 354	\$ 354
2017	\$ 501	\$ 286	\$ 328	\$ 328
2018	\$ 517	\$ 295	\$ 357	\$ 357
2019	\$ 612	\$ 349	\$ 433	\$ 433
2020	\$ 499	\$ 284	\$ 375	\$ 375

Average price from the first reporting period in July of each year.
 Source: Illinois Production Cost Report (GX_GR210)USDA-ILL,
 Dept of Ag Market News Service, Springfield, IL
www.ams.usda.gov/mnreports/gx_gr210.txt
www.ams.usda.gov/LPSMarketNewsPage