Technical Support Document (TSD)

for the Final Revised CSAPR Update for the 2008 Ozone NAAQS

Docket ID No. EPA-HQ-OAR-2020-0272

EGU NO_X Mitigation Strategies Final 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 final Revised CSAPR Update for the 2008 Ozone NAAQS. In developing the final 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 final 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 NO_X. Over time with use, the catalyst will degrade and require replacement. The ammonia or urea reagent is also consumed in the NOx conversion process. Fully operating an SCR includes maintenance

[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 "SCR_and_SNCR_OS_Rates_and_Costs_Revised_CSAPR_Final.xlsx" for detailed cost estimates using the Retrofit Cost Analyzer for SCR and SNCR operation and installation.

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 degredation 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 degredation, or NOx 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 SCR-controlled coal-fired units that operated in 2019 in the United States on a per ton of NO_X removed basis. EPA updated the set of units based on the latest version of the NEEDS database (December 2020) and commenter data on the proposed rule. Doing so eliminated some units that, at proposal, EPA had previously characterized as existing coal-fired units with SCR. This final assessment covered 199 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", NOx rate, the NOx 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 NOx 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. In this section and in the next section (where we examine the cost of returning a unit with an idled SCR to full operation), from the full set of units, we focused on a subset of 132 units that had minimum "input" NOx emission rates of at least 0.2 lb/mmBtu).[7] For these units, 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. Commenters suggested focusing on a subset of units (i.e., those in the 12-state region) and accounting for coal type in the analysis. EPA examined each of these alternatives (conservatively assuming all units burn subbituminous (rather than bituminous) and limiting the geography to 12-states and notes that these factors do not appear to result in large changes to the costs. When rounded, the 90th percentile cost and average cost remain at \$800/ton and \$700/ton, respectively for the bituminous units and decrease slightly to \$700/ton and \$600/ton for the subbituminous units. EPA elected to use the proposed methodology that

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[3] See the file "SCR_and_SNCR_OS_Rates_and_Costs_Revised_CSAPR_Final.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 NOx 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 NOx 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.

relies on a nationwide dataset (while accounting for an updated fleet of units) as described in the preamble section VI.B.

Thus, EPA concludes that $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.

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] As was shown 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 NOx rate and third best controlled NOx rate, EPA evaluated all of the VOM and FOM costs for the 132 coal-fired units with SCR in the contiguous United States that were operating in 2019 and had minimum "input" NOx emission rates of at least 0.2 lb/mmBtu.[9] EPA updated the set of units based on the latest version of the NEEDS database (December 2020) and eliminated some units that, at proposal, EPA had characterized as coal-fired with existing SCR. As was done before at proposal, 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 $1,100/ton of NOx removed. Specifically, this assessment found that 120 of the 132 units demonstrated VOM plus FOM costs lower than $1,600/ton of NO_X removed and 125 or the 132 units had costs at or below $1,800/ton of NOx removed.[10] Commenters suggested that EPA should limit the analysis to the 12

[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 "SCR_and_SNCR_OS_Rates_and_Costs_Revised_CSAPR_Final.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 NOx 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

state region and should also account for the effects of coal type. EPA examined each of these alternatives and found that the suggested refinements often did not result in the kinds of changes asserted by the commenters. For example, focusing on the 12-state region and accounting for coal rank, the cost at the 90th percentile for units that exclusively use bituminous coal was $1,500/ton while the cost for subbituminous was $1,200 per ton (based on only 4 such units in the region). In regard to a nationwide coal rank assessment, the 90th percentile costs were $1,600 and 2,000/ton, for bituminous and subbituminous, respectively. EPA found that even with these different filters and subcategories suggested by the commenter, these costs continued to be similar to the $1,600 per ton cost level EPA identified using the illustrative units and a nationwide assessment.

Based on its proposal analysis and subsequent assessment of comments, the EPA concludes that a cost of $1,600/ton of NO_X removed is a representative cost for the point at which restarting and fully operating idled SCRs becomes widely available to EGUs. EPA notes that the majority of units identified as having SCR optimization potential in the Revised CSAPR Update Rule are already partially operating and best reflected by the $800 per ton optimization cost for partially operating units rather than this $1,600 per ton cost for fully idled units.

NO_X Emission Rate Estimates for Full SCR Operation

EPA examined the ozone season average NO_X rates for 220 coal-fired units in the contiguous U.S. 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 updated the set of units based on the latest version of the NEEDS database (December 2020) and eliminated some units based on commenter input that, at proposal, EPA had characterized as coal-fired with existing SCR. EPA examined ozone season average NO_x rates from 2009 onwards as it constitutes the period since annual NO_x programs, rather than just seasonal programs, became widespread in the eastern US with the start of CAIR in 2009. EPA captured this dynamic with its baseline choice as this regulatory development could affect SCR operation (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 are 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, in the final rule, EPA utilizes the same rationale and methodology for identifying the rate that it did at proposal and with the CSAPR Update. EPA maintains that the timeline should include most-recent operational data (i.e., up through 2019) and continue to extend back to 2009. Considering the emissions data over the full time-period of available

number of tons of NOx 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_and_SNCR_OS_Rates_and_Costs_Revised_CSAPR_Final.xlsx" for details.

data that includes expected annual operation of SCRs (i.e., 2009-2019) results in a third-best rate of 0.08 lb/mmBtu. EPA notes that half of the EGUs achieved a rate of 0.068 lbs NO_X/mmBtu or less over their third-best entire ozone season (see Figure 1). EPA verified that in years prior to 2019, the majority (approximately 95%) of these same coal-fired units with identified optimization-based reduction potential in 2019 data 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 0.068 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).

As was the case with the cost, EPA received comment that the region of analysis should be limited to just units within the 12-state region and should also be specific to coal rank (among other factors). Examining the results for the 12-state region, the average rate increased slightly to 0.085 lb/mmBtu. If segmented for coal rank, the average for bituminous coal units increased to 0.09 lb/mmBtu, while the average rate for subbituminous units decreased to 0.058 lb/mmBtu. In all scenarios, the 0.08 lb/mmBtu assumption was revealed to be widely achievable for SCR controlled units regardless of region or coal rank. As noted above, 95% of the units identified as having SCR optimization potential have demonstrated this level of performance. Moreover, as some commenters pointed out, the average emission rates used are inherently conservative as they are driven up by a few units that are not operating their SCRs at all. If EPA removes these SCRs from the inventory of units used to determine the optimization rate, or, instead focuses on the median rate, rather than the average, the emission rate is lower than 0.08 lb/mmBtu. EPA's review of the historical data at the unit-level compared to the assumed representative rate of .08 lb/mmBtu for SCR-controlled units not optimized confirmed that the methodology and resulting rate assumption is both reasonable and viable for SCR-controlled units on average.

Commenters also suggested adjusting the time-period of analysis. Some argued that the time period should be extended (e.g., starting in the mid to early 2000's), while other argued it should be shortened (i.e., starting in 2013). The agency explains the reasons why most of these changes were not adopted in the preamble section VI.B. EPA examined each of the alternatives suggested by the commenter and several the resulting estimates are included in the workbook in the docket. EPA did not adopt shortening the time-period because the Agency believes that operation from the 2009 time-period (when most units began facing annual operational requirements for their SCR controls) could be representative of current operation and maximizes the amount of data available. The commenter's assertion that the fleet fundamentally altered its operation starting in 2013 with systematic change in capacity factor affecting performance of unit's SCRs is not sufficiently supported given the EPA's analysis suggesting that operation of SCR is largely unaffected once the SCR is operational (i.e., at greater than about 25% hourly capacity factors).[13,14]

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12 See "Optimizing SCR Units with Best Historical NOx Rates Final.xlsx" included in the Docket

13 See the "Discussion of Short-term Emissions Limits" document for additional details.

14 See " SCR_and_SNCR_OS_Rates_and_Costs_Revised_CSAPR_Final.xlsx" for details.

Based on the all the factors above, and the seasonal and monthly findings below, the agency concludes an emission rate of 0.08 lb NO_X/mmBtu is widely achievable by the portion of EGU fleet with SCR optimization potential identified.[15]

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.

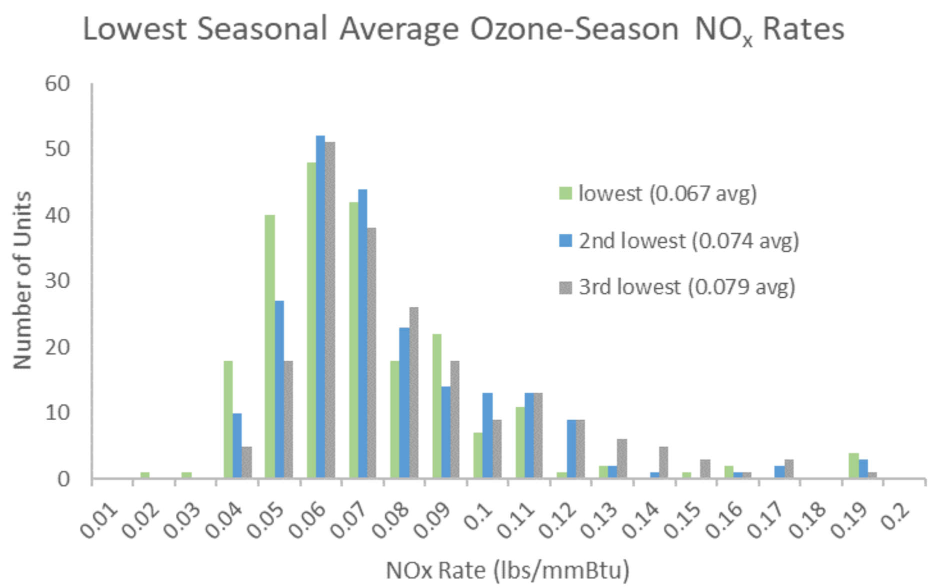
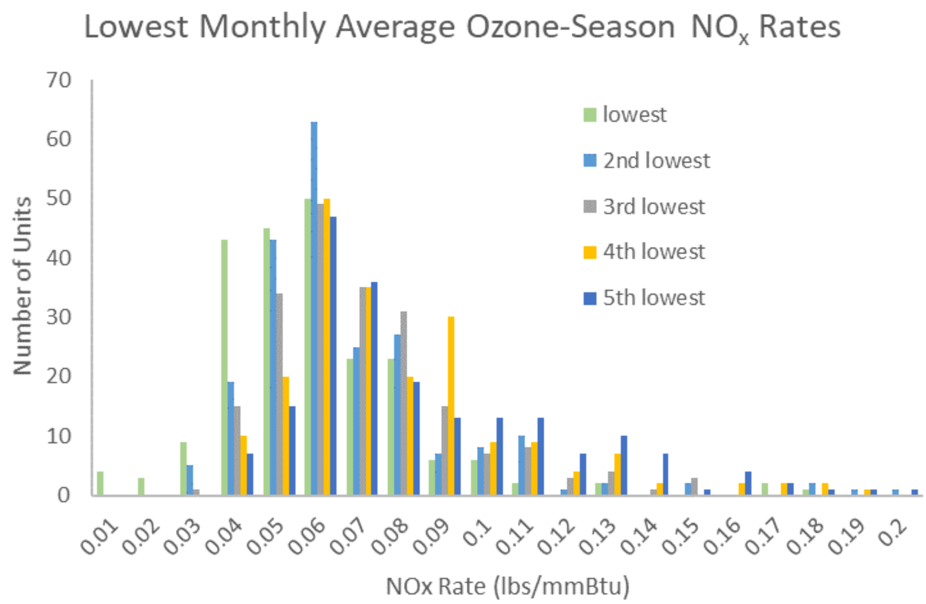


Figure 2. "Frequency" distribution plots for coal-fired units with an SCR showing their monthly average NO_X emission rates (lbs/mmBtu) during ozone seasons from 2009-2019. For each unit, the lowest, second lowest, third lowest, fourth lowest, and fifth lowest monthly average NO_X rates are illustrated.

[15] EPA also reviewed historical hourly data and observed reduced capacity factor was not a primary driver of emission rate performance at levels above approximately 25% for SCR controlled coal units in 2017 and in 2019. See "Hourly_Vs_Ozone_Season_NOx_Rates_for_SCR_Units_2017_and_2019.xlsx" and "Discussion of Short-term Emissions Limits", document ID number EPA-HQ-OAR-2018-0295-0026" for details.



Cost Estimates for Optimizing and Restarting and Optimizing 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 NOx removal with SNCR than would be required to achieve the same level of NOx 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 for NOx.[16],[17] 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

[16] 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. The documentation notes that NOx removal efficiencies of only 15% are possible in some instances. 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).

[17] *Steam 41ed* (2005), lists 20-30% conversion of NOx as typical, with up to 50% possible under certain circumstances.

$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% NOx 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.

As described in the preamble, EPA received comment suggesting that EPA had overestimated the cost of SNCR optimization for units covered in this rule. Commenters noted that many units appeared to be currently partially or fully operating their SNCRs under the existing CSAPR Update. Using the retrofit cost analyzer, EPA reexamined the VOM cost components for all existing coal-fired units with SNCR (and for the units within the 12-state region). EPA assessed the cost of optimizing SNCR at units where the control is partially operating, similar to how it assessed such cost for partially operating SCRs at units. EPA focused on the VOM component associated with the urea reagent, since it is the principle cost associated with NOx removal. The other VOM components, dilution water procurement and heat rate penalties associated with use of dilution water and auxiliary power requirements, are already partially incurred because the units are currently operating. EPA concludes (consistent with its data from proposal) that $1,800/ton is broadly representative of the costs faced by units to fully optimize their SNCRs when the unit is already partially operating the control.

EPA examined the group of units that have SNCR optimization potential and assessed whether the units are currently partially operating but not necessarily optimizing their SNCRs. In these cases, the units would not incur the full VOM and FOM costs of restarting an idled control. Rather, these units could be expected to incur only the VOM cost of using additional reagent to achieve the additional NOx emission reductions (thereby only incurring the reagent costs of $1,820/ton, as described above). EPA assessed whether SNCRs were partially operating by comparing each unit's 2019 historical rate to its identified optimization emission rate (identified as mode 2 in the NEEDS file) used in the engineering analytic step 3 efforts. A percent difference less than 25% is an indicator that the SNCR is already partially operating (as 25% NOx removal is a representative average of what SNCRs may achieve when going from no operation to full operation). The majority, 23 of the 29, appeared to be partially operating based on this one indicator alone. For the remainder, EPA compared the historical highest rate for the unit (dating back to 2009) to its 2019 historical emission rate. If the percent difference between the two was substantial, this was yet another indicator that the SNCR was partially operating at the unit in 2019 (hence it was achieving a lower rate in 2019). Between these two indicators, EPA determined that nearly all SNCRs with optimization potential identified in the 12 states were at least partially operating their controls during 2019. Given the comments and these findings, EPA concluded that a VOM reagent-centric cost of $1,820/ton was the most reasonable representative cost of additional reductions for units with SNCR optimization potential (recognizing that unit-specific cost will vary above and below that value).

Table 1: Ozone-season NOx Emission Rates (lb/mmBtu) for Units with SNCR Reduction Potential							
Facility	**State**	**Boiler**	**2019 Rate (lb/mmBtu)**	**SNCR Optimization Rate (lb/mmBtu)**	**% Change in Rate (2019 v optimization)**	**Historical Max Seasonal Rate (2009-2019)**	**% Change Between 2019 and Historical Max**
Grant Town Power Plant	West Virginia	1A	0.312	0.162	48.1%	0.349	11%
Grant Town Power Plant	West Virginia	1B	0.307	0.161	47.4%	0.346	11%
Brame Energy Center	Louisiana	2	0.194	0.127	34.6%	0.222	13%
Brame Energy Center	Louisiana	3-1	0.040	0.026	33.7%	0.053	25%
Whitewater Valley	Indiana	1	0.358	0.256	28.4%	0.358	0%
Whitewater Valley	Indiana	2	0.381	0.275	27.8%	0.381	0%
Yorktown Power Station	Virginia	3	0.195	0.152	22.1%		
Joliet 29	Illinois	82	0.092	0.075	19.0%		
Joliet 29	Illinois	72	0.081	0.066	18.2%		
Joliet 29	Illinois	71	0.079	0.066	17.2%		
Joliet 29	Illinois	81	0.092	0.078	15.6%		
Virginia City Hybrid Energy Ce	Virginia	1	0.071	0.062	12.8%		
Dolet Hills Power Station	Louisiana	1	0.222	0.195	12.1%		
Virginia City Hybrid Energy Ce	Virginia	2	0.069	0.060	12.0%		
Joliet 9	Illinois	5	0.099	0.087	11.7%		
Clover Power Station	Virginia	1	0.288	0.264	8.3%		
Genesee Power Station	Michigan	01	0.179	0.165	7.6%		
IPL - Harding Street Station (E	Indiana	50	0.034	0.032	7.5%		
Panther Creek Energy Facility	Pennsylvania	1	0.123	0.116	5.9%		
Southampton Power Station	Virginia	2	0.120	0.114	5.3%		
Southampton Power Station	Virginia	1	0.120	0.114	5.2%		
H L Spurlock	Kentucky	3	0.066	0.063	3.6%		
Will County	Illinois	4	0.091	0.088	2.6%		
R M Schahfer Generating Stat	Indiana	15	0.126	0.123	2.5%		
Hopewell Power Station	Virginia	1	0.114	0.111	2.2%		
Fort Martin Power Station	West Virginia	2	0.281	0.275	2.1%		
Hopewell Power Station	Virginia	2	0.114	0.111	2.0%		
Powerton	Illinois	52	0.099	0.097	1.9%		
Fort Martin Power Station	West Virginia	1	0.273	0.268	1.7%		

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 a 25% removal potential for SNCR was assumed as a representative removal rate reflecting the typical SNCR performance. To identify the optimized value 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 NOx mode rates are calculated from historical data and reflect operation of existing post-combustion controls.[18] Four modes are identified for each unit to, among other things, identify their emission rates with and without their post-combustion

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

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 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 NOx rate (lb/mmBtu)" column.[19] 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. EPA also evaluated its final rule unit-specific optimization rates for SNCR-controlled units in the 12-state region by comparing the assumed optimization rate against demonstrated past performance of the unit (in periods prior to 2019). EPA's analysis indicated that these rates were not only reasonable, but had been demonstrated as achievable by each unit in prior periods.[20]

Cost Estimates for Installing Low NOx 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 2a shows average NO_X rates from coal-fired units with various combustion controls for different time periods.

Table 2a: Ozone Season NO_X Rate (lb/mmBtu) Over Time for Coal-fired Units with Various Combustion Controls*

	Years Between 2003 and 2008		Years Between 2009 and 2018		Year = 2019	
NOx Control Technology	**NOx Rate (lb/mmBtu)**	**Number of Unit-Years**	**NOx Rate (lb/mmBtu)**	**Number of Unit-Years**	**NOx Rate (lb/mmBtu)**	**Number of Unit-Years**
Overfire Air	0.384	476	0.294	603	0.221	30
Low NOx Burner Technology (Dry Bottom only)	0.351	1,062	0.270	1,126	0.209	46
Low NOx Burner Technology w/ Overfire Air	0.306	464	0.228	672	0.202	41
Low NOx Burner Technology w/ Closed-coupled OFA	0.266	341	0.223	326	0.187	20
Low NOx Burner Technology w/ Separated OFA	0.222	451	0.191	584	0.159	33
Low NOx Burner Technology w/ Closed-coupled/Separated OFA	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 NOx Burners (LNB) or

[19] 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

[20] See "SNCR Assessment from Engineering Analysis Data" in the docket for this rulemaking.

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 2b below).[21] 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 NOx burners with Close-Coupled and Separated Overfire Air). For each unit, EPA's understanding of the current NOx control configuration can be found in the "NOx Comb Control" column of the NEEDS v6 () database file.[22] EPA identified whether a unit has combustion control upgrade potential by comparing the Mode 1 NOx Rate (lbs/mmBtu) with the Mode 3 NOx Rate (lbs/mmBtu) within NEEDS. If the Mode 3 value is lower than the Mode 1 value, than 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 NOx 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.[23] 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.[24] 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.[25] 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.

Commenters suggested that EPA's cost analysis is flawed because, in their view, at least for certain units, completely new combustion control installations could be necessary to achieve the emission rate

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

[22] 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

[23] 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.

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

[25] 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.

performance proposed by EPA. As noted below, EPA finalized some adjustments to EPA's emission rate performance for combustion controls to better reflect combustion control upgrade potential through installation of incremental controls. As in the CSAPR Update, EPA's cost equations consider incremental improvement and results in a $1,600 per ton being a reasonable representative cost for the technology. EPA's analysis indicates some upgrades would likely cost less and some would cost more, but that $1,600 per ton was a reasonable reflection of the cost at which this technology becomes widely available and it is consistent with both cost assumptions made in the CSAPR Update rule and empirical data observing most units already having these state-of-the-art controls in place during environments with a lower allowance price incentive. See EPA's Response to Comment Document (State Budget Chapter) for further response to this comment.

<u>NOx Emission Rate Estimates for LNB upgrade</u>

EPA received significant comment on the combustion control upgrade potential and resulting emissions rate. Commenters specifically identified a need for EPA to update its data year and inventory of sources to reflect 2019 and units that did not have post-combustion controls. Furthermore, commenters suggested that EPA ensure its rate assumptions were robust against coal rank for this type of technology.

As was detailed in the final rule preamble section VI.B, EPA updated its assumed performance rate for state-of-the-art combustion controls based on the most recent representative historical data and an updated inventory of units with like boiler configuration and control status using the October 2020 NEEDS file.[26] (This inventory and methodological update resulted in an adjustment that raised the average emission rate assumption to 0.199 lb/mmBtu for combustion controls on dry bottom wall-fired units and 0.147 lb/mmBtu for tangentially fired units. As described in the preamble, commenters provided detailed analysis of how other unit considerations, such as coal rank, can result in large deviations on what has been historically demonstrated with this combustion control technology. Based on these comments and EPA review of historical performance data for tangentially-fired units by coal type with state-of-the-art combustion controls. EPA determined it was appropriate to use the 0.199 lb/mmBtu rate for both tangentially and wall-fired units in this final rule. As noted by commenter, many of the likely impacted units burn bituminous coal, and the 0.147 lb/mmBtu nationwide average for tangentially-fired (inclusive of subbituminous units) was below the 2019 demonstrated emission rate of state-of-the-art combustion controls for bituminous coal units of this boiler type.

As noted above, EPA derived its performance rate assumptions for combustion control upgrade 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: 1) dry-bottom wall-fired boilers and 2) tangentially-fired boilers. EPA looked at the current rate of existing units of each firing configuration and that already had state-of-the-art combustion controls (SOA CC). EPA estimated the average 2019 ozone season NOx emission rates for all such units by firing type. As suggested by commenter, it did not include any units that had post-combustion controls installed as their historical rate would be indicative of not just combustion control potential, but also post-combustion control potential. For dry bottom wall-fired coal boilers with "Low NOx Burner" and "Overfire", there were 39 units averaging 0.199 lb/mmBtu. For tangentially-fired coal boilers with "Low NOx Burner" and "Closed-coupled/Separated OFA", there were 54 units averaging 0.147 lb/mmBtu. At proposal, EPA had used 2016 data and an inventory of units that included some units that had post-combustion controls present as well.

[26] As noted in the preamble, the most recent representative historical data at the time of this update was 2019 data.

Next, EPA identified the current boiler type of each unit in the covered 12-state region. It then applied the information shown below in Table 2b regarding state-of-the-art configurations compared to that unit's reported combustion control figuration to determine whether the unit had combustion control upgrade potential. Starting with dry-bottom wall-fired boilers, EPA verified that the average performance rate identified above for this boiler configuration with state-of-the-art combustion controls 1) resulted in reductions consistent with the technology's assumed % reduction potential when applied to this subset of units, and/or 2) had been demonstrated by both subbituminous and bituminous coal units with state-of-the-art combustion controls in its 2019 dataset. Therefore, EPA affirmed as reasonable the combustion control upgrade configuration assumed emission rate of 0.199 lb/mmBtu for dry-bottom, wall-fired boilers that were upgrading to state-of-the-art combustion controls.

EPA applied the same approach for tangentially-fired coal boilers. It observed that in 2019 no bituminous burning units with this boiler type (and no post-combustion controls) had met the 0.147 lb/mmBtu average for this boiler type and control configuration (which was heavily weighted by subbituminous units with such combustion controls) as noted by commenter (see table 2c). It also noted that the 0.147 rate lb/mmBtu would imply a greater percent reduction for some bituminous units with upgrade potential than EPA identified as representative for the technology. Therefore, given these two findings and the bituminous orientation of the fleet with state-of-the-art combustion control upgrade potential covered in this action, EPA determined that the 0.199 lb/mmBtu was also appropriate for tangentially-fired units in this action as that rate satisfied both criteria.[27]

Table 2b: 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 =NOx Burner Technology, LNC1=Low NOx coal-and-air nozzles with close-coupled overfire air, LNC2= Low NOx Coal-and-Air Nozzles with Separated Overfire Air, LNC3 = Low NOx Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air, OFA = Overfire Air

Table 2c. 2019 average NOx rate for units with state-of-the-art combustion controls for tangentially-fired boilers (lb/mmBtu)	
Bituminous	0.199
Bituminous, Subbituminous	0.172
Subbituminous	0.134

[27] See "State-of-the-art Combustion Control Data" in the docket for this rulemaking

Weighted Average	0.147

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 NOx 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 NOx rate of at least 0.2 lb/mmBtu and an assumed NOx 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).[28] In this instance, the median value is $5,800/ton.[29]

Some commenters suggested that SNCRs can perform better than 25% and that EPA should assume more reduction potential from this technology. EPA finalized the same removal rate assumption in this final rule as it had proposed in Revised CSAPR Update Rule and finalized in the CSAPR Update Rule. EPA notes that this is a representative rate, and that some units can likely perform better than this removal rate and that others may perform at lower removal rates.

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 was used in the CSAPR Update Rule, EPA's power sector modeling, and in the Retrofit Cost Analyzer.[30] Historically, reported unit-level emission rate data further

[28] For the input NO_X rate for units with SNCR NOx 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 NOx rate. For the input NO_X rate for units that lack SNCR post-combustion controls, we used the most recent available ozone-season average NOx rate (i.e., 2019).

[29] See the file "SCR_and_SNCR_OS_Rates_and_Costs_Revised_CSAPR_Final.xlsx" for detailed cost estimates using the Retrofit Cost Analyzer for SCR and SNCR operation and installation.

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

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.[31] 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 NOx rate of 0.4 lb/mmBtu and 80% NOx 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, NOx 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 NOx 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 the 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 final rule, 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 NOx rates of at least 0.2 lb/mmBtu prior to installation of the post-combustion control and decreasing to rates of 0.07 lb/mmBtu following control installation and were assumed to use bituminous coal.[32] 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, these assumptions produce a median value of $9,600/ton and a 90th percentile value of $13,700/ton. For a baseload coal capacity factor of 80%, the 90th percentile is less than the $9,600/ton value.[33]

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

[32] For the input NO_X rate for units with SNCR NOx 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 NOx rate. For the input NO_X rate for units that lack SNCR post-combustion controls, we used the most-recent available ozone-season average NOx rate (i.e., 2019).

[33] See the file "SCR_and_SNCR_OS_Rates_and_Costs_Revised_CSAPR_Final.xlsx" for detailed cost estimates using the Retrofit Cost Analyzer for SCR and SNCR operation and installation.

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.[34] 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 NOx 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 criterion.[35] 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.[34] 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

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[34] 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.

[35] See the "2019 NOx 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.

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/or 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.

Moreover, hourly unit-level data, such as that shown in preamble figure 1 section VI.B, clearly show that SCR performance can improve within a 2-month time frame. Specifically, when controls are partially operating (as EPA has demonstrated is the case in nearly all units with optimization potential), the data shows the hourly emission rate varying significantly (reflective of SCR performance) over hours that occur well within two months of one another. For instance, the size of the rectangle showing hourly NOx rates for the unit when the control is partially operating in 2017 and 2018 reflect the 25^{th}-75^{th} percentile hours. The top left graphic shows emission rates varying between approximately 0.22 b/mmBtu to 0.07 lb/mmBtu in 2017 for instance. This variation, reflective of SCR performance, is occuring within a two-month time span, indicating the ability for quick improvements in control performance even controlling for load levels.[36]

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.[37] Industry has demonstrated retrofitting LNB technology controls on a large unit (800 MW) in under six months (excluding permitting). 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. EPA received significant comment on the timing assumptions regarding the implementation of state-of-the-art combustion controls such as LNB and responds to those comments in the final rule preamble section VI.B.

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 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,

[36] Unit-level hourly emission rate data at www.epa.gov/ampd. See also "Miami Fort Hourly Emission Rate at Capacity Factor of 50%-80%" in the docket for this rulemaking. This file shows the emission rate changes occuring withing two months of one another.

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

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.[38] On a regional scale, the estimate for installing SCR at multiple boilers on multiple plants is in excess of 39 months. EPA determined these technologies would not be available at regional scale prior to the start of the of the 2024 ozone season. See preamble section VI.C for more discussion on post combustion control retrofit timing. EPA received significant comment on its timing assumptions regarding post-combustion control retrofit options and responds to those comments in section VI.B and VI.C of the preamble.

This final rule, like prior interstate transport rules, considers 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 emission reductions and 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 IPM 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 $1800/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.

Table 3: Regional Coal and Gas Summer Generation Changes Base to Cost Threshold Case (2021, GWh)

[38] http://nepis.epa.gov/Adobe/PDF/P1001G0O.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%

<u>Additional Mitigation Technologies Assessed but Not Finalized in this Action</u>

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 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 (in reference to their use during “peak” electricity demand), 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 from these units 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 NOx rate by the average 2019 ozone season NOx 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's data sets 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 NOx 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 NOx emissions (Figure 5).

For the example HEDD day, the largest shares of peak hour NOx 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 NOx 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 NOx emissions from oil units (Figure 6). With peak hour NOx 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. This rule, Subpart 227-3,[39] entitled "Ozone Season NOx Emission Limits for Simple Cycle and Regenerative Combustion Turbines," applies to simple cycle combustion turbines (SCCTs) with a

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

nameplate capacity of 15 MW or greater that supply electricity to the grid. The regulation contains two compliance dates with increasingly stringent NOx limits, as follows: by May 1, 2023, all SCCTs subject to the rule must meet a NOx emission limit of 100 ppmvd,[40] and; by May 1, 2025, gas-fired SCCTs must meet a NOx 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 NOx 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.

EPA received comment on potentially including these mitigation technologies in the final Revised CSAPR Update Rule and addresses those comments in section VI.B. of the preamble.

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

[40] Parts per million on a dry volume basis at 15% oxygen. Using a heat rate of 15,000 BTUs/KWh identified in New York's background materials for the rule and the alternative 3 lbs NOx/MWh limit equating to 100 ppmvd, the equivalent emission rate would be approximately .2 lb/mmBtu and significantly lower for the full implementation of 25 ppmvd. See https://www.dec.ny.gov/docs/air_pdf/siprevision2273.pdf

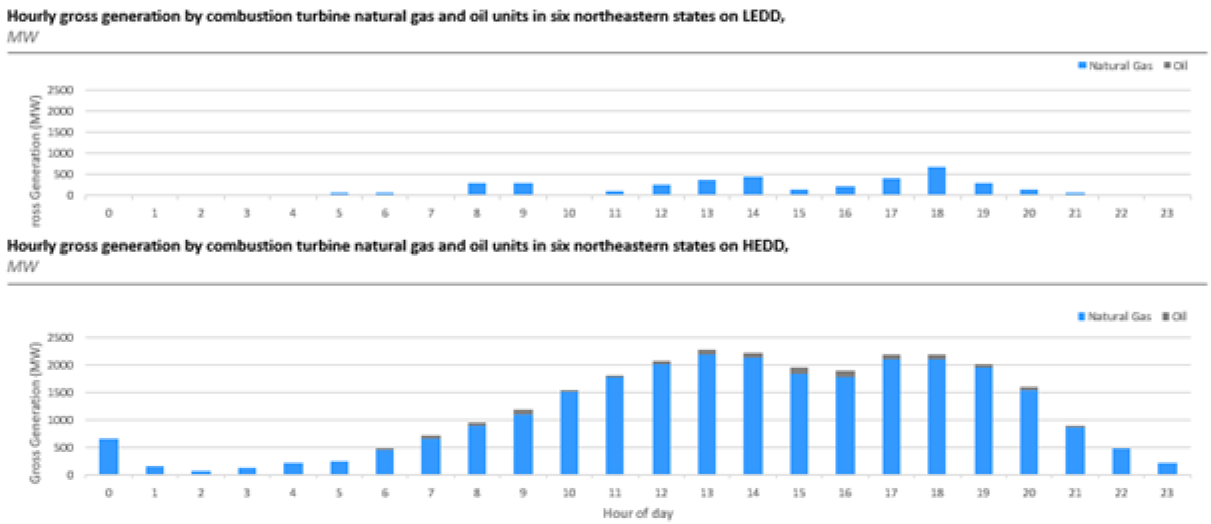


Figure 4. Percentage share of peak hour NOx emissions by unit type across region and states on an exemplary LEDD

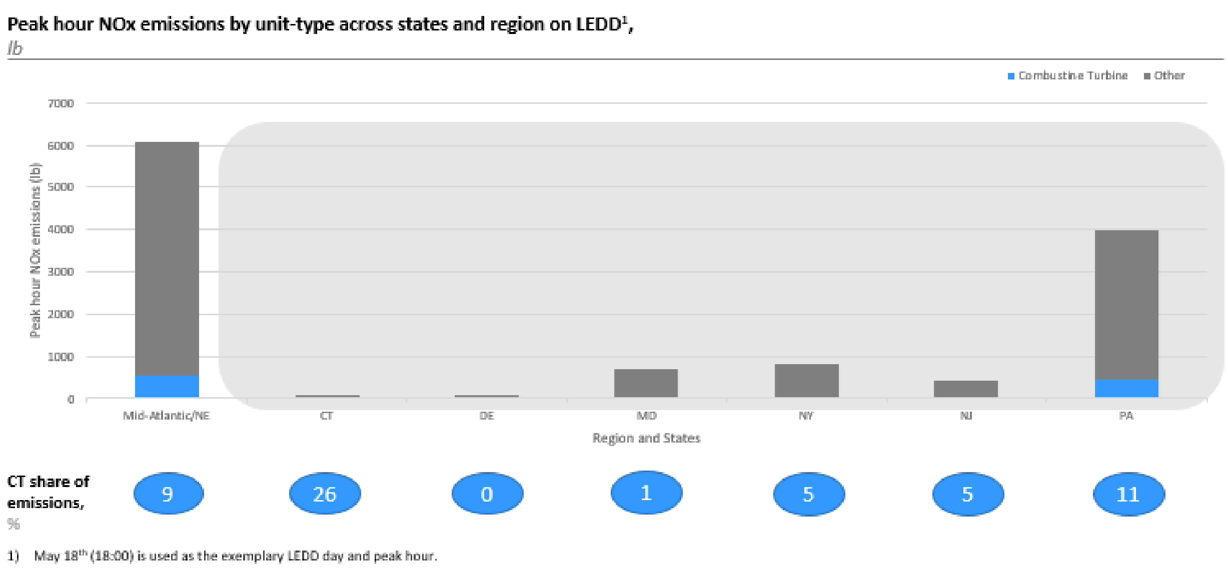


Figure 5. Percentage share of peak hour NOx emissions by unit type across region and states on an exemplary HEDD (Source: Air Markets Program Data (AMPD), ampd.epa.gov, EPA, 2020)

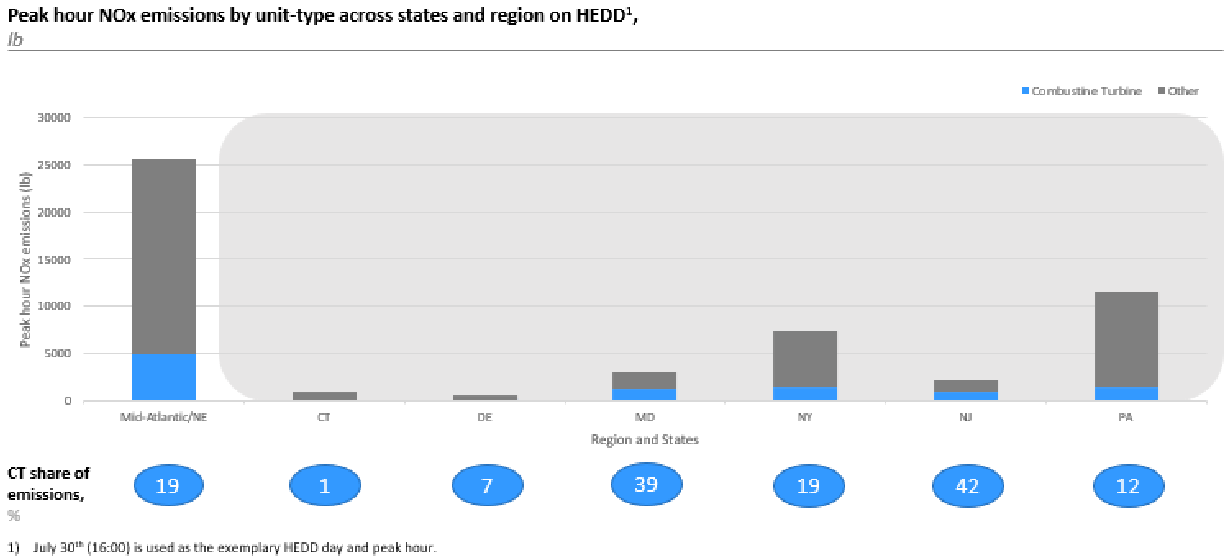
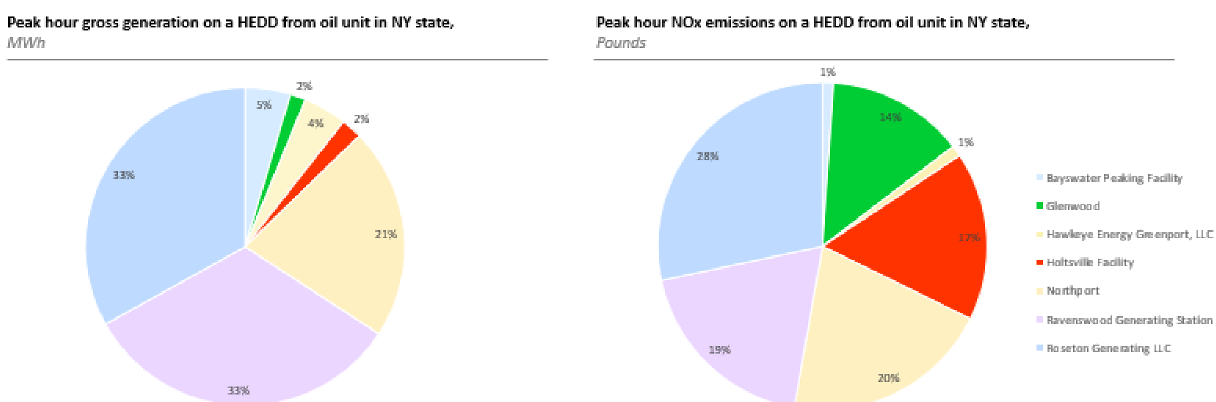


Figure 6. Peak hour generation and emissions on HEDD by oil units in NY as a percentage (Source: Air Markets Program Data (AMPD), ampd.epa.gov, EPA, 2020)



Mitigation Strategies at Small Municipal Solid Waste (MSW) Units

EPA also invited comment on whether other EGUs not covered by the existing CSAPR programs should be considered and responds to that comment in preamble section VI.B and in the NOx Controls for EGUs section in the Response to Comment document. Stakeholders have pointed out that grid-connected MSW combustors 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 invited comment in the proposal 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 MSW combustors in the eleven states that EPA's modeling indicates significantly contribute or interfere with maintenance of the 2008 ozone NAAQS in the New York metropolitan area. EPA regulates certain pollutants, including NOx, under Sections 129 and 111 of the CAA for MSWs and other types of solid waste incineration units. These requirements are reflected in new source performance standards (NSPS) and emission guidelines found in 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.[41] 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,[42] and New Jersey has adopted a NOx emission limit of 150 ppm applicable to MSW units of any size.[43] 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)[44]

	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

[41] See "White Paper on Control Technologies and OTC State Regulations for Nitrogen Oxide (NOx) Emissions from Eight Source Categories", Final Draft, February 10, 2017.
[42] 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.
[43] See Section 7:27-19.12, Municipal Solid Waste (MSW) Incinerators, of the New Jersey State Department of Environmental Protection Administrative Code.
[44] 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

Washington	0.22	0.51	44%	0.38

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 NH_3 & Urea costs ($/ton) [from USDA]

year	NH_3 (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-IIL,
Dept of Ag Market News Service, Springfield, IL
www.ams.usda.gov/mnreports/gx_gr210.txt
www.ams.usda.gov/LPSMarketNewsPage