139 E. 4th Street EM740
Cincinnati, OH 45202

December 14, 2020

VIA www.regulations.gov

U.S. Environmental Protection Agency
EPA Docket Center
Docket ID No. EPA-HQ-OAR-2020-0272
1200 Pennsylvania Avenue NW
Washington, DC 20460

Duke Energy Comments on "Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS" (85 Fed. Reg. 68964 (Oct. 30, 2020))

To Whom It May Concern:

Duke Energy submits the following comments in response to the U.S. Environmental Protection Agency's ("EPA" or "Agency") "Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS" (the "Proposed CSAPR Revision" or "Proposal" or "Proposed Rule"). 85 Fed. Reg. 68,964 (Oct. 30, 2020). Duke Energy is one of the largest electric power holding companies in the United States. Its regulated utility operations serve approximately 7.7 million electric customers located in six states in the Southeast and Midwest. Its Commercial business owns and operates a growing portfolio of renewable energy assets across the United States.

As a general matter, Duke Energy and other industry stakeholders observe that EPA plans to sign a final rule by March 14, 2021, so that new requirements will be in place for the 2021 ozone season. However, EPA's accelerated schedule has produced a proposal with a number of critical errors. Consequently, the Agency is proposing additional requirements that, upon close examination, are not justified for a number of reasons. First, EPA did not demonstrate through modeling that any of the sources will have a significant impact in 2021 as the court directed in the *Wisconsin* decision, but instead interpolated from 2023 modeling. Second, the greatly reduced proposed state NO_x budgets assume emission control performance (Selective Catalytic Reduction (SCR) and low NO_x combustion) that is overstated and not representative of the current capabilities of the electric generating units (EGUs) in the proposed 12-state Group 3 region. Furthermore, EPA proposes significant changes to the way it would administer the CSAPR program without recognizing or addressing a number of significant adverse consequences.

While EPA plans to complete its rulemaking by the court's March 14, 2021 deadline, any rule it finalizes must address the specific remedy required by the court and demonstrate that any new requirements are properly justified, *reasonably* achievable, and can be accomplished in the time provided without major disruptions to the industry. EPA has not yet done this. In fact, EPA has proposed a rule that primarily revisits one of the key aspects that the court determined EPA had adequately addressed in the CSAPR Update Rule – that the rule had adequately addressed the control technology capabilities of EGUs equipped with SCR – while providing no meaningful analysis of other potentially more significant sources of emissions.

Given the various shortcomings of this proposal, Duke Energy asserts that it is highly unlikely that EPA can complete a final rule on its current schedule that properly addresses both the court's direction and corrects these important errors. Many of the issues identified in the comments of Duke Energy and other industry stakeholders will require additional modeling and analysis that EPA has acknowledged it must complete. Because the necessary changes are widespread, it is very important that the public be given ample opportunity to review and comment on the revised analyses.

Since 2004, EGUs have been subject to ozone season NO_x restrictions with the NO_x SIP Call Rule and progressively more stringent requirements under the Clean Air Interstate Rule (CAIR), CSAPR, and the CSAPR Update rules. The affected EGUs have responded to each of these programs and have taken the necessary steps to achieve compliance with the state budget requirements for each of those rules. However, EPA is now proposing a rule in which it is expected that SCR-equipped EGUs can, within weeks after EPA issuance of a final rule, achieve large additional ozone season NO_x emission reductions in the new 12-state Group 3 region (including Indiana and Kentucky where Duke Energy operates eight large SCR-controlled EGUs) by simply using more ammonia and replacing catalyst more frequently. Although some reductions can be achieved for the next ozone season, the level of reductions EPA is requesting will take additional time and expense that EPA's analysis has overlooked. Duke Energy's comments are summarized below, and detailed comments are attached.

- EPA has not justified the deep EGU NO_x budget reductions proposed for the 12-state Group 3 region considering the very small benefit to a very small number of downwind nonattainment and maintenance areas EPA identified and the considerable impact the proposed rule will have on EGUs.
- The proposal is not consistent with the *Wisconsin* remand because it does not provide a modeled analysis of the significant impact of upwind sources in 2021, and instead of analyzing the potential non-EGU emission source reductions that EPA acknowledged it had not done in the CSAPR Update Rule, it further regulated the one group of sources that the court acknowledged EPA had indeed adequately addressed.
- EPA's incorrect handling of coal unit retirements in setting the declining state budgets and unit allocations between 2021 and 2024 leads to unreasonably reduced future year allocations for units remaining in operation. This treatment of planned unit retirements in state NOx budgets beyond 2021 creates an inequity for units that remain in operation and has the consequence of causing overcontrol because these units will be subject to emissions allocations that are significantly more stringent than a budget that is based on the measures that EPA has deemed to be cost-effective.
- EPA's assumed NO_x performance expectation for existing SCRs of 0.08 lb/MMBtu (or less for many units) is unrealistic. EPA's use of data for all EGUs nationwide in its analysis of SCR performance capability does not accurately assess the capability of the EGUs in the smaller 12-state affected region. In addition, EPA has not demonstrated that technological improvements have occurred that justify reducing from the 0.10 lb/MMBtu SCR NO_x emission rate that it determined was reasonably achievable in the CSAPR Update Rule just four years ago, particularly after the court in *Wisconsin* deemed EPA's conclusions on control of units equipped with SCR to be reasonably based. Duke Energy recommends that EPA retain the 0.10 lb/MMBtu SCR NO_x emission rate for use in setting state budgets.
- EPA's assessment of what are cost-effective reductions ($/ton NO_x reduced) is incorrect. EPA's analysis estimates for SCR-equipped units that a reduction to a rate of 0.08 lb/MMBtu can be achieved at about $800 per ton (less than the $1,600 per ton level) and are therefore deemed "cost-effective." EPA assumes that EGUs can meet this reduction with more frequent catalyst replacement and the injection of more ammonia. Some additional reductions can be achieved by increasing ammonia usage, which would likely be within EPA's cost range; however what EPA has not recognized is that the additional reductions necessary to achieve the proposed budgets will require additional expenditures such as the

reworking of catalyst replacement plans and other changes. The actual cost of these reductions will often far exceed EPA's cost-effective levels. EPA should limit the expected reductions to only those that are within the cost-effective range; failure to do so could constitute "overcontrol."

- It is not possible to implement most of the significant upgrades to existing SCR equipment by the 2021 ozone season that are necessary to achieve the substantially lower proposed NO_x budgets. As an example, more frequent catalyst replacement requires additional maintenance outages that are not possible in the roughly six weeks from when EPA plans to finalize the rule and the start of the 2021 ozone season. In addition, other projects such as low NO_x combustion improvements, physical changes to SCR gas flow path and catalyst bed design, upgrades to ammonia storage and injection systems, improved process control instrumentation, and additional measures upstream of the SCR to address fouling at low-load operation require time for planning and execution.
- EPA compounds the problem for EGUs to attain compliance in the 2021 ozone season by restricting the number of banked Group 2 CSAPR ozone season NO_x allowances by capping the transfer to the proposed 21% Assurance Level. EPA should minimize the impact on allowance markets and provide some degree of flexibility to manage operations by providing a greater number of converted Group 2 allowances to be placed in the final Group 3 bank.

In addition to the above concerns, which directly impact Duke Energy, Duke Energy also supports the comments provided by the Class of '85 Regulatory Response Group, the Edison Electric Institute, the Midwest Ozone Group, the Utility Information Exchange of Kentucky, and the Indiana Electric Association, which also address technical and legal issues associated with the proposal.

Should you have any questions regarding these comments, please contact J. Michael Geers, Manager, Environmental Programs, at Michael.Geers@Duke-Energy.com.

Sincerely,

J. Michael Geers, P.E.
[signed electrically]

J. Michael Geers, P.E.
Manager, Environmental Programs Group
Duke Energy

COMMENTS OF DUKE ENERGY

on the

Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS

85 Fed. Reg. 68964 (Oct. 30, 2020)

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

1.0 EPA's Proposed EGU NOx budgets Are Not Justified Considering the Very Small Benefit to Downwind Nonattainment and Maintenance Areas and Are Not Consistent with the *Wisconsin* Remand.

The Edison Electric Institute and the Midwest Ozone Group (MOG) have analyzed data from EPA's Air Pollutant Emissions Trends Data webpage. Figure 1 below shows actual and projected NOx emissions from key source sectors from 2011 through 2028, demonstrating that the electric utility sector has made significant reductions and is a small fraction of overall NOx emissions within the U.S. The power sector's overall share of NOx emissions has decreased significantly over the past 30 years and in 2019 was responsible for only about 11% of total U.S. anthropogenic NOx emissions, down from 26% in 1990. Within the stationary source sector, EGUs currently account for only 28% of total emissions, and non-EGU sources account for 72% of the emissions. EPA's national data and projections show that emissions from EGUs have been reduced to the point that the gains from further EGU NOx reductions produce ever diminishing benefits.

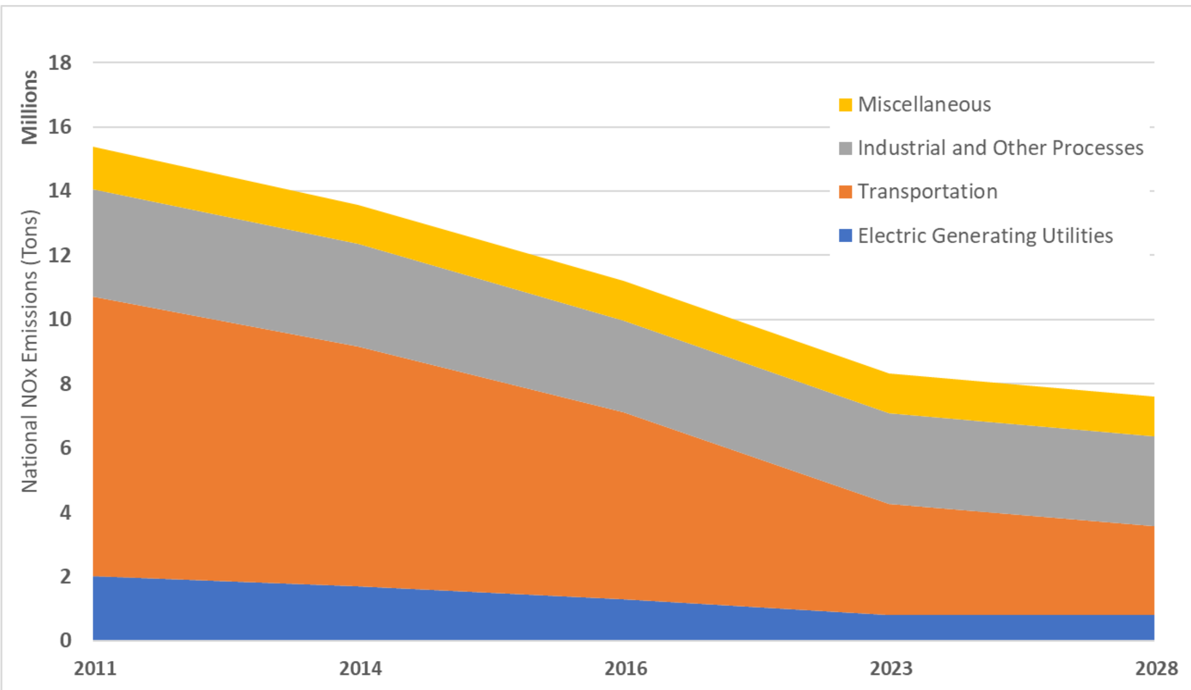


Figure 1: Actual and Projected NOx Emissions in the U.S. By Sector[1]

EPA did not provide a modeled demonstration that emissions from sources in the 12-state Group 3 region will have a significant impact on ozone nonattainment or maintenance in 2021 as the Court directed in the *Wisconsin* decision and instead inappropriately relied on linear interpolation of 2023 modeling. A linear interpolation cannot accurately represent 2021 projected ozone values or downwind impacts, because first the models are not linear and second because the model does not properly account for the timing of emissions reductions within the states. These two important considerations show that EPA has not provided an appropriate basis to determine that

[1] Source: Midwest Ozone Group analysis of data obtained from EPA emissions modeling files: (ftp://newftp.epa.gov/Air/emismod/2016/v1/reports/all_2011v63_2014v71_2016v1_county_summary_09-Oct-2019.zip).

the 12 identified states will continue to have a significant impact in 2021, and therefore, require additional regulation.

The extraordinarily stringent state EGU NOx budgets in the Proposal are not justified considering the very small potential benefit to downwind nonattainment and maintenance areas. EPA's interpolated state-by-state contribution analysis shows that more than 70% of the total downwind contribution from the proposed 12-state Group 3 region would be attributed to just the three states closest to the Connecticut nonattainment and maintenance monitors, and only Louisiana has any measurable contribution to the maintenance monitor in Texas[2]. Yet the stringent budgets in EPA's proposal will have a very significant impact on EGU operations across the Group 3 region.

EPA's proposed NOx budgets for the Group 3 region will result in a reduction of 38% regionwide from the current CSAPR Update Rule budgets for these states. Many of these states will see budgets reduced by greater than 50%. Yet EPA's analysis of the impact of these very deep cuts solely from the EGU sector shows that there is little modeled improvement in air quality. EPA's analysis shows an average air quality improvement at the four monitored receptors in Connecticut and Texas of only 0.19 ppb, and the maximum improvement was only 0.24 ppb. This air quality improvement resulting from the deep regionwide reductions in EGU emissions falls short of what EPA has deemed a "significant" impact of 1% of the 75-ppb ozone standard. This illustrates why EPA's exclusive focus on EGU emissions is flawed and will continue to fail if the goal is to achieve meaningful improvements in air quality. Because EPA has not assessed all emissions sources and the potential impacts at various cost levels, it has not determined what is truly effective, and EPA needs to do so before concluding that it is reasonable to impose further controls on EGUs that have already installed SCR.

Despite the national emissions trends, EPA has not provided any detailed analysis of controls and cost-effectiveness for the non-EGU sector to demonstrate why the sole focus on EGU controls in the CSAPR program is warranted. The approach to address reductions primarily based on further control of EGUs with SCR is inconsistent with the *Wisconsin* decision, which concluded that EPA had reasonably determined the level of performance for those EGUs in the final CSAPR Update Rule and that EPA had not met its obligation to fully assess emissions from other sources, specifically non-EGUs.

Until EPA provides a detailed evaluation of the potential reductions from non-EGUs, an assessment of the cost effectiveness of those reductions, and the projected impacts of those reductions on downwind ozone nonattainment and maintenance areas, EPA cannot conclude that its proposed regulation based almost entirely on further control of EGUs equipped with SCR is reasonable, cost-effective, and does not result in overcontrol for those EGU sources.

2.0 EPA's Incorrect Handling of Coal Unit Retirements in Setting State and Unit Level Budgets Leads to Unreasonable Tightening of Unit Level Budgets.

Two issues arise when considering allocations to retired units. The first is how to factor retired units into the state budget and unit allocations. In all the NOx trading programs to date, the overall total state budgets have remained fixed when units retire. The only time the state budgets were reduced was when a new more stringent trading program such as the 2016 CSAPR Update rule

[2] Table VI D-3 indicates that Illinois and Indiana have a contribution of 0.02 ppb to Maintenance of the Houston Texas monitor which is insignificant and unmeasurable. FR 68989

was implemented. The second is whether a retiring unit should retain allocations for some period after retirement.

In the current rulemaking, EPA proposes to change its approach and reduce the total state budgets between 2021 and 2024 on a yearly basis by recognizing planned unit retirements but also to continue allocating those increasingly smaller budgets to all units, including the retired units. EPA's inconsistent and arbitrary approach would use the total baseline period heat input *without the retired units* to calculate the state budgets while using the total baseline heat input *with the retired units* to determine unit allocations. This is a significant change from the past methodology where allocations from retired units would remain a part of the overall state budget once the program was in place. This approach penalizes units that continue to operate because they would receive fewer allocations due to other unit(s) shutdowns. In the past with a fixed state budget, these operating units would still receive the same allocations and not be harmed. Tables 1 & 2 demonstrate the process in the State of Indiana.

State	HI - Ave High 3 Year*	2021 State Budget	2022 State Budget	2023 State Budget	2024 State Budget
Indiana	512,637,264	12,500	11,998	11,998	9,447
*: Heat input held consistent despite unit retirements.					

Table 1: Table showing how the total heat input (including retired units) is used to establish unit level allocations remains constant from 2021-2024 while the state allowance budgets decrease.

As shown in table 1, the heat input used to apportion the unit allocations remains consistent across the years whereas the actual state budgets take an additional reduction of approximately 25% through 2024 almost entirely due to projected retirements.[3] Using EPA's apportionment methodology, this results in a considerably lower unit-level allocation for units that continue to operate. This raises concerns of overcontrol and cost effectiveness. EPA determined that effective operation of SCRs on units that currently have them installed is the most cost-effective method of control. Utilizing this analysis, EPA established 2021 state budgets and subsequently, unit allocations, based on a 0.08 lb/MMBtu emission rate (although in comments below, Duke Energy asserts that the state budgets were established based on a more stringent emission rate than 0.08 lb/MMBtu level). For calendar years 2022-2024, EPA's intention was to develop unit allocations consistent with the analysis utilized in setting 2021 allocations. However, the methodology that EPA follows does not result in the intended outcome. By not adjusting the inputs to unit level calculations consistent with the state budget calculations due to unit retirement, it affectively apportions allocations to Duke Energy and other units at a more stringent rate than 0.08 lb/MMBtu. Table 2 is a comparison of the effective emission rate when setting the 2021 unit allocations and the 2024 unit allocations.

[3] The only other contribution to the reduced budget after 2021 is attributed to EPA's application of low NOx combustion (SOA CC) at Whitewater Valley Unit 3.

State	Facility Name	Unit ID	HI - Ave High 3 Year	2021 Proposed Allocations	2024 Proposed Allocations	2021 Effective Emission Rate	2024 Effective Emission Rate
IN	Cayuga	1	14,081,828	384	287	0.055	0.041
IN	Cayuga	2	14,517,961	396	296	0.055	0.041
IN	Gibson	1	16,518,060	451	336	0.055	0.041
IN	Gibson	2	15,502,122	423	316	0.055	0.041
IN	Gibson	3	17,295,233	472	352	0.055	0.041
IN	Gibson	4	15,288,132	417	311	0.055	0.041
IN	Gibson	5	14,520,995	396	296	0.055	0.041

Table 2: Change in effective emission rate due solely to other unit retirements.[4]

As can be seen in Table 2, the Duke Energy Indiana units would have to operate at a significantly more stringent emission rate in order to comply with the 2024-unit allocation level.[5] This is mostly due to the retirement of other units within the state of Indiana. There is only one instance where EPA has identified additional control mechanisms in later years and that accounts for about 1% of the reduction in the state budget. Furthermore, retaining EPA's proposed allocation methodology to retired units would allow owners of those units to forego more cost-effective emission reductions at their other owned units forcing more costly reductions by other utilities who continue to operate.

This issue could be mitigated if EPA were to adopt a consistent basis for establishing the state budgets and the unit allocations, for example using a multi-year average of recent heat input that is the same for both setting the budget and allocating the allowances. This concept is discussed further in Section 3.0 below to address other concerns with how state budgets are set.

Duke Energy does support the approach EPA has taken in previous NOx budget programs that once the program <u>is in effect and budgets have been set</u>, additional retired units would keep their allocated share of the budget for some period after retirement (five years in the current CSAPR Update Rule).[6]

3.0 EPA Incorrectly Utilizes Different Heat Input Baselines When Setting State and Unit Level Budgets.

The calculation for setting of state budgets and unit allocations uses two different heat input baselines, which creates disparities in the stringency of the rule in both the budgets and allocations. When setting the state-level budgets, EPA relied on data from a single year (2019), whereas when setting the unit allocations, EPA relied on an average of the three highest years over a five-year period. First, utilizing a single year's data to establish the state budget does not consider the variation in operation that a unit may experience from year to year. Many things could impact a unit's operation in a one-year period that do not demonstrate how a unit or a group of units within a region typically operate. For example, a unit could have experienced an extended outage, volatility of fuel prices could impact a unit's dispatch, or there may be significant variations

[4] This analysis omits the two Edwardsport units, which EPA incorrectly identified as coal-fired and SCR-controlled. Edwardsport is, in fact, an integrated gasification combined cycle plant, which is not equipped with SCR.
[5] Although not shown in this example, the trend is similar for 2022 and 2023.
[6] Under this approach, allowances would continue to be allocated to retired units. Put differently, if the state budget does not include historical heat input for retired units, then those retired units would not receive an allocation.

in weather impacting operations of EGUs. Utilizing a multiyear average heat input value when establishing the baseline numbers accounts for this variability. For this reason, Duke Energy does not support EPA's proposed reliance on 2019 alone to set state budgets or unit allocations, nor does it support a change to using only 2020 as its basis. Shifting to 2020 would continue to rely on one year's data, and 2020 has not been a representative year for any industry due to the COVID-19 pandemic.

Second, utilizing separate heat inputs when establishing state budgets and unit allocations effectively changes, and in most cases reduces, the emission rate EPA identified to be cost-effective. EPA determined that an average emission rate of 0.08 lb/MMBtu was the appropriate level of NOx emissions for units equipped with SCR. EPA established the state budgets utilizing 0.08 lb/MMBtu (or the 2019 actual value, if less), in conjunction with the 2019 heat input. When setting the actual unit allocations, EPA relied on the state budgets established using a 0.08 lb/MMBtu rate, but applied a 3-year average heat input based on the period 2015-2019 to apportion the allocations among the affected units in the state. Using this methodology significantly shifts the balance on how NOx allowances are distributed within a state in a way that is not representative of the actions intended by the rule (i.e., achieve reductions primarily by enhancing the performance of SCRs). In effect, this methodology creates winners and losers in the distribution of allowances, which would force some controlled units, even if currently achieving exceptional performance of NOx controls, to find ways to further reduce emissions, incur additional costs for control, or shift load to other units. Table 3 illustrates this disparity just for EGUs with SCR operated by Duke Energy Indiana.

State	Facility Name	Unit ID	2019 Heat Input	HI - Ave High 3 Year	NOx Rate Used Setting Budgets	2019 Unit Nox Emissions used for Setting State Budgets	Emission Rate - Nox emissions State Budgets Divided by 3 Year Ave HI	2021 Proposed Allocations	Emission Rate - Proposed Allocations divided by 3 Year Ave HI
IN	Cayuga	1	10,369,735	14,081,828	0.08	415	0.059	384	0.05
IN	Cayuga	2	6,136,972	14,517,961	0.08	245	0.034	396	0.05
IN	Gibson	1	13,069,530	16,518,060	0.08	523	0.063	451	0.05
IN	Gibson	2	9,772,453	15,502,122	0.07	326	0.042	423	0.05
IN	Gibson	3	6,349,580	17,295,233	0.08	254	0.029	472	0.05
IN	Gibson	4	6,729,616	15,288,132	0.08	269	0.035	417	0.05
IN	Gibson	5	11,301,968	14,520,995	0.08	452	0.062	396	0.05

Table 3: Comparison of emission rates based on differing heat input basis.

Table 3 shows not only is there a discrepancy between the emission rates when applying the 2019 heat input and the 3-year average heat input to the unit-level emissions used in setting state budgets, but there are also issues when comparing the 3-year average heat input used for unit allocations to the 2019 proposed allocations. The last column shows the rate at which a unit would have to perform in order to meet the unit allocations if its level of operation were comparable to the 3-year average heat input. Each Duke Energy Indiana unit would need to meet an ozone season average of 0.05 lb/MMBtu to support operation in a future ozone season at the level of the 3-year average heat input, which is much less than what EPA identified as a cost-effective level at 0.08 lb/MMBtu.

As mentioned previously, this problem can be addressed by determining state budgets and unit allocations using the same, consistent approach for both using a multiyear average heat input basis. Additionally, it is advisable to limit the time frame for the analysis to only include years since the 2016 CSAPR Update (ozone seasons from 2017-2019). This would more accurately reflect current operations, accounting for changes in unit load profiles where units are operating increasingly more at minimum loads where SCR performance is not as effective, while also accounting for the emissions reductions that resulted from the 2016 CSAPR Update.

4.0 EPA's Assumed SCR Performance Target of 0.08 lb/MMBtu is Incorrect.

EPA has assumed an unrealistic average NOx performance goal for existing SCRs of 0.08 lb/MMBtu, which does not reflect the capabilities, operating constraints, and changes that have occurred within the electric utility industry in recent years. Over approximately the past five years, coal-fired EGUs have moved to increased cycling operation, with substantial amounts of operating time at minimum load conditions, which are not favorable to SCR operation. This trend is expected to continue. In the current proposal, EPA has increased the stringency from the 0.10 lb/MMBtu emission rate that was used for the 2016 CSAPR Update rule, but it has not demonstrated that EGUs have made the improvements necessary that would enable them to achieve greater levels of NOx reduction on a consistent long-term average. Duke Energy recommends that EPA continue to use an average emission target of 0.10 lb/MMBtu to represent the overall level of performance expectation for purposes of calculating Group 3 budgets.

4.1 Assessing SCR Performance Using Data From all Contiguous 48-States Does Not Accurately Represent EGU Capability in the Smaller 12-State Group 3 Region.

EPA's analysis of SCR performance for coal-fired EGUs using data from all 48 contiguous states is not representative of the current capabilities and the limitations of the SCRs installed on EGUs in the proposed 12-state Group 3 region. On page 5 of the "EGU NOx Mitigation Strategies Proposed Rule TSD" (TSD), EPA states that it "examined the ozone season average NOx 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 NOx rate." The TSD concludes that the average of the 3rd lowest values for all units was 0.08 lb/MMBtu and that value would represent the average reasonably achievable emissions rate for units equipped with SCR.

There are many different reasons why SCRs were installed on EGUs in the contiguous 48 states. Many of the units are in states that are not part of the CSAPR or any other NOx budget program. These units have generally installed SCRs to meet specific "command-and-control" requirements, such as NSPS and PSD/NSR requirements applicable to new units, state-specific regulations or legislation, etc. These SCRs were installed at different times and with different removal expectations. They use different fuel types, serve different types of boilers, and operate under different conditions and load profiles. All these factors have a profound impact on SCR performance. To properly identify levels of uniform control stringency, EPA needs to evaluate the performance of only the coal-fired EGUs equipped with SCR specifically in the 12-state Group 3 region. Failure to do so will not only produce an erroneous emission rate but will also result in an inaccurate cost of control.

The 12-state Group 3 region burns far more bituminous coal than sub-bituminous compared to the 48-state contiguous area. Bituminous coal has a much higher sulfur content, particularly fuel from the Northern Appalachian and Illinois Basin regions. The sulfur is converted by the combustion process into sulfur dioxide (SO_2) and a small amount of sulfur trioxide (SO_3), which then pass through the boiler to the SCR. Additional SO_3 is formed from the oxidation of SO_2 by the SCR catalyst. EGUs burning higher sulfur coal typically require catalyst specially designed to reduce the oxidation of SO_2 to SO_3. Excess SO_3 contributes to catalyst fouling when it reacts with ammonia and can potentially lead to high plume visibility. Catalyst with a lower SO_2 to SO_3 conversion rate is also less efficient at reducing NOx emissions and typically has a shorter life. To avoid the deposits that can plug the catalyst, an SCR-controlled unit with higher levels of flue gas SO_3 must raise its minimum load to operate at higher flue gas temperatures or it must turn off the ammonia below a minimum operating temperature specified by the catalyst vendor. A plugged SCR results in less surface area for the necessary reaction to take place reducing SCR performance.

Another problem with Illinois Basin coal is that certain sources contain high levels of trace materials that poison the catalyst and cause it to deactivate much faster and reduce its NOx removal potential. The units equipped with SCR in the Group 3 region that experience this problem include a number of Duke Energy units in Indiana and Kentucky. For these units to begin achieving the level of performance proposed by EPA, they would require much more frequent catalyst replacements, potential restrictions on operation, and the installation of other mitigation measures. As will be described later in these comments, the marginal cost of NOx reductions associated with accelerated catalyst replacement and other measures will far exceed those values projected by EPA.

Using the same methodology that EPA explained in the TSD, Duke Energy reproduced EPA's analysis of SCR emission rates but included only units in the limited 12-state Group 3 region. The histogram in Figure 2 below shows the distribution of 1st, 2nd, and 3rd best NOx emissions rates in the same fashion that EPA provided in the TSD, except it only includes the 144 units in the Group 3 region that meet the criteria of coal-fired EGUs with SCR, rather than the 250 units included in the chart on page 7 of the TSD.

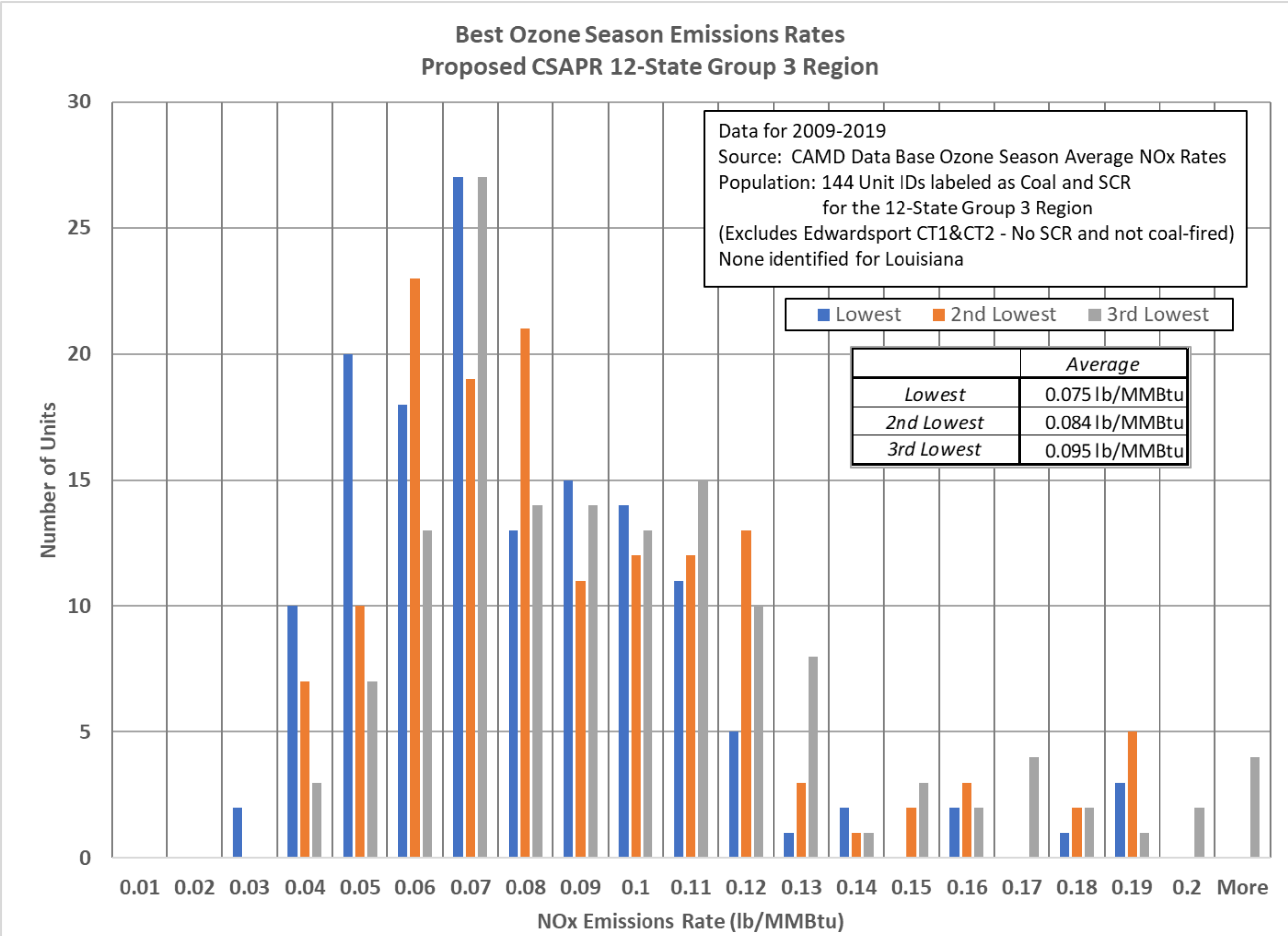


Figure 2: "Frequency" distribution plot for coal-fired units with an SCR in the 12-state region showing average NOx emissions rates during the ozone season from 2009-2019.

As Figure 2 above depicts, the results are significantly different when the units analyzed include only those in the Group 3 Region. The 3rd lowest emission rate from the analysis of the smaller 12-state region increases from 0.08 lb/MMBtu to 0.095 lb/MMBtu.

As discussed further in Section 4.2 below, Duke Energy also believes that EPA's analysis should have considered a more recent period to better represent significant changes in generation that have impacted the operation of coal-fired EGUs and SCR performance. This period captures changes to the industry resulting from implementing the MATS rule, increased use of natural gas, and recent unit retirements. Using the period 2013-2019, this analysis of NOx performance shows that the average of the 3rd lowest emissions rates increases to 0.106 lb/MMBtu, as shown in Figure 3. This result is consistent with the 0.10 lb/MMBtu basis that EPA used in the 2016 CSAPR Update Rule.

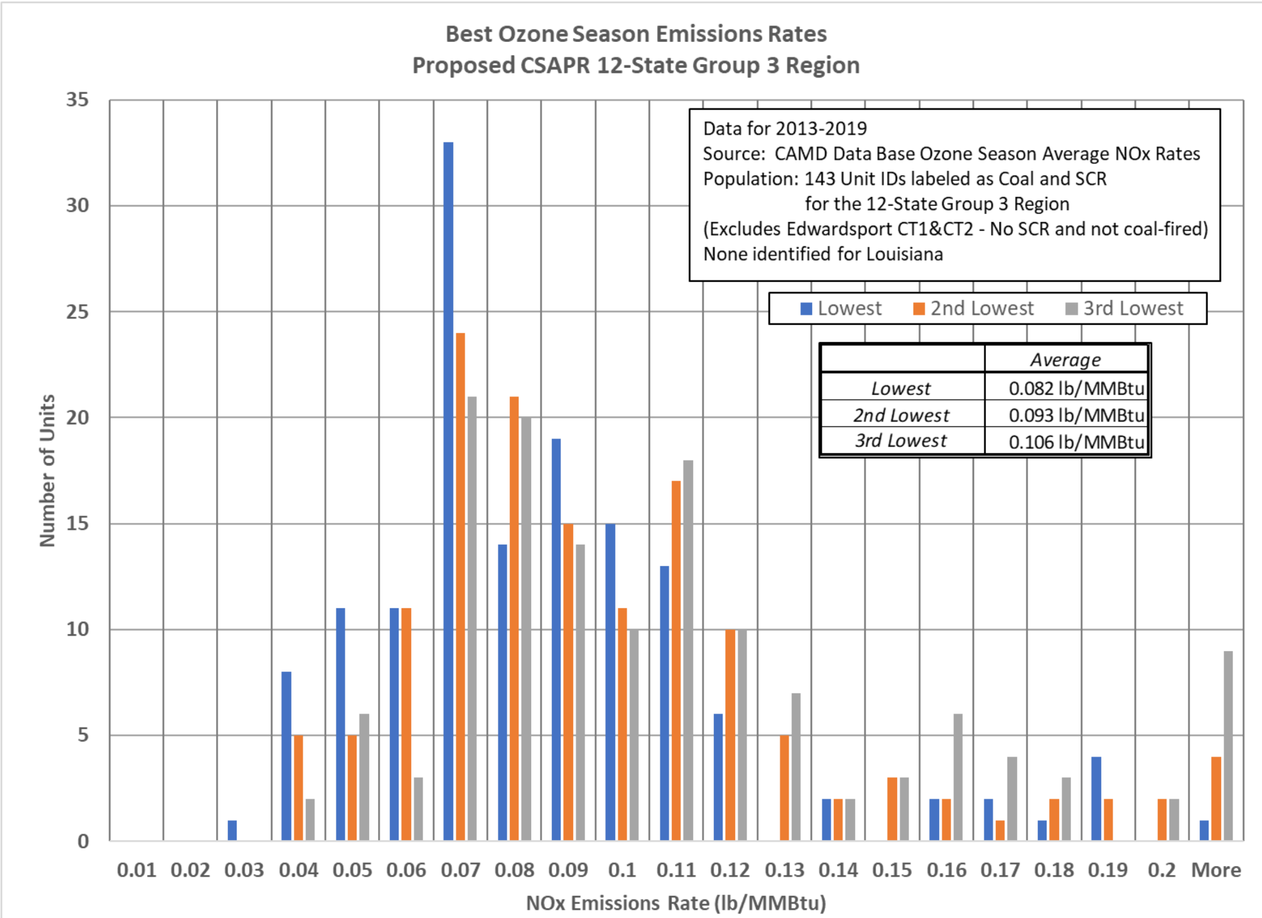


Figure 3: "Frequency" distribution plot for coal-fired units with an SCR in the 12-state region showing their average NOx emissions rates during the ozone season from 2013-2019.

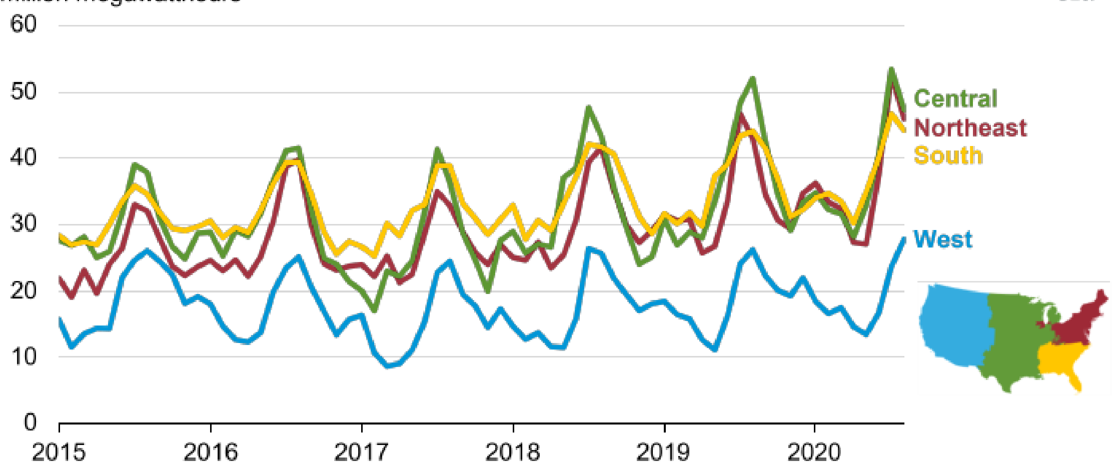
4.2 Increased gas use impacts coal operation and the state budget

In recent years, there have been significant changes in the operation of coal-fired EGUs from an increasing shift to newer natural gas-fired combined cycle units and a large growth of renewable generation. Because the manner of unit operation has a direct bearing on SCR performance (e.g., low-load operation below the SCR's minimum operating temperature and process control issues associated with cycling the unit), it is more appropriate for EPA's review to include only the past five to six years' worth of data. Indeed, EPA's TSD refers to the spreadsheet used to conduct the statistical analysis, and columns AH to AJ of that spreadsheet provide an analysis of the three best years using the period 2013 – 2019.[7] The average of the 3rd best performance for that period is 0.09 lb/MMBtu, or 12.5% higher than the analysis using the period 2009 – 2019. EPA has not explained why it believes the longer lookback period is more representative, and Duke Energy believes that, as noted in Section 4.1 above, the more recent period would be a better representation.

[7] *See* "EGU NOx Mitigation Strategies Proposed Rule TSD," p. 5, and the spreadsheet "SCR_Historical_OS_Rates_Revised_CSAPR_Update_Proposal.xlsx."

As an illustration of the changes impacting the industry, the U.S. Energy Information Administration (EIA) recently released a report demonstrating a dramatic increase in natural gas-fired generation over the past five years (2015 – 2019) in the U.S., including all of the states within the Group 3 region affected by this rule. Figure 4 below shows that annual natural gas-fired generation increased by 17% in the South region, 20% in the Central region, and 31% in the Northeast region. (Note that EIA's definition of regions is based on the integrated grid operations systems and does not follow state boundaries.) Increased natural gas-fired generation results in more cycling operation of coal-fired power plants and more time operating at minimum load conditions, which has a direct and negative impact on SCR performance.

Monthly U.S. natural gas-fired electric generation by region (Jan 2015–Aug 2020)
million megawatthours



Source: U.S. Energy Information Administration, *Power Plant Operations Report*
Note: *Central* consists of the Electric Reliability Council of Texas (ERCOT), Southwest Power Pool (SPP), and Midcontinent Independent System Operator (MISO). *South* consists of Southeastern Electric Reliability Council (SERC) and Florida. *Northeast* consists of New York Independent System Operator (NYISO), Independent System Operator New England (ISO-NE), and PJM Interconnection (PJM). *West* consists of California, Northwest, and Southwest.

Figure 4. EIA Chart Showing Increased Natural Gas-fired Generation Since 2015

4.3 The 3rd Best Average Performance EPA Used to Set State NOx Budgets is Actually Lower than 0.08 lb/MMBtu.

EPA concludes that units equipped with an SCR should be able to meet a 0.08 lb/MMBtu emission rate regionwide based on its analysis that, ***on average***, the 3rd best NOx performance for coal-fired EGUs equipped with SCR has met that level. However, EPA's budget-setting process does not accurately reflect that assumption. EPA's budget calculations treat the 0.08 lb/MMBtu emission rate as a ***maximum*** for any individual existing SCR and not an average. If an SCR-equipped unit's 2019 ozone season NOx emission rate was below 0.08 lb/MMBtu, then EPA used the unit's actual emission rate to factor into the state budget. If the emission rate was greater than 0.08 lb/MMBtu, then EPA capped the emission rate at 0.08 lb/MMBtu and calculated a new NOx tonnage to factor into setting the state budgets. Using this methodology results in a regionwide average that is more stringent than 0.08 lb/MMBtu. In fact, for the 2021 budget calculations including only the coal-fired units with SCR, the average emissions rate (dividing the total budget share of these units by the total heat input assigned to the units) is 0.07 lb/MMBtu.

This average is even lower than the NOx emission rate EPA set for new EGUs.[8] If EPA used an average emissions rate to represent the technological capability of EGUs with existing SCR, then it must apply that average to all units in setting the budget. It is not appropriate to reduce the NOx rate for units that happened to operate below 0.08 lb/MMBtu in 2019 (or whatever baseline period EPA uses in the final rule). Because it is not necessarily representative of typical performance, it makes the state budgets more stringent than EPA's claimed basis for establishing cost-effective controls (thus leading to overcontrol) and will make it difficult for EGUs to generate excess allowances needed to establish an effective Group 3 market.

4.4 EPA has not Demonstrated that Group 3 SCRs are Generally Capable of Achieving an Emission Rate of 0.08 lb/MMBtu or Lower

EPA has not demonstrated that the capabilities of the -controlled EGUs in Group 3 have advanced such that they are now capable of improving their aggregate emission rate from the 0.10 lb/MMBtu assumed for the 2016 Update rule to 0.08 lb/MMBtu assumed in this proposal. EPA's SCR performance assessment is flawed and did not analyze technology limitations of the SCRs that were installed under previous NOx budget programs. EPA simplistically concludes that all EGUs need to do to enhance their performance and achieve 0.08 lb/MMBtu or better is to increase catalyst replacement frequency and use more ammonia without analyzing what it takes to implement these changes.

For many units, simply changing catalyst more frequently may not provide the ability to meet an average SCR performance of 0.08 lb/MMBtu for NOx. Many of the SCRs that were retrofitted onto existing EGUs were designed for compliance with the earlier NOx reduction programs implemented since 2004, such as the NOx SIP Call, CAIR, and CSAPR. Retrofit SCRs were generally built on base loaded units with a design removal efficiency consistent with the less restrictive requirements of those programs. The designs of those retrofit SCRs do not necessarily incorporate all the enhanced capabilities that would be necessary to achieve and sustain the low NOx emissions rate envisioned by the proposal. For example, many SCRs were designed for an 80 to 85% removal efficiency and not 90% because it was not necessary.[9] Similarly, advanced low NOx combustion techniques were not necessary.

To achieve lower EGU NOx emission rates (higher removal efficiency), companies will, in many cases, need to undertake significant upgrades to their NOx control process, including enhanced combustion controls, accelerated catalyst replacement, potentially reconfigured equipment, and increased ammonia injection system capacity to provide more reagent and optimized distribution. In addition, units may require modifications to improve flue gas flow and distribution or install advanced process controls instrumentation. Utilities will also need to evaluate installation of SO_3 mitigation controls ahead of the SCR to better allow for lower load/lower temperature operation. All these considerations are part of how SCRs are designed and operated and influence the level of NOx performance. Fundamentally changing the expectations for NOx performance on these units will take significant time for engineering, planning, and scheduling of outages to implement the required changes. EPA has analyzed none of these issues in any detail and has instead

[8] The New Source Performance Standard for EGU boilers subject to Subpart Da, which commenced operation after May 3, 2011, are subject to an emissions limit of 0.7 lb/MWH (gross) on a 30-boiler operating day basis, which is roughly equivalent to an emissions rate of 0.08 lb/MMBtu.
[9] Many of Duke Energy's SCRs were designed with a nominal removal efficiency of approximately 85% for a certain specific set of operating conditions, which are not the same conditions under which these units currently operate.

assumed that whatever is needed can just happen in the roughly six weeks between when EPA intends to sign a final rule and the beginning of the 2021 ozone season.

4.5 Comparison of the Proposal's Requirements with Other Regulatory Programs.

Another way to assess the stringency of EPA's proposed performance value for coal-fired EGUs with SCR in the current rulemaking is to compare it with other regulatory requirements and the applicable limitations. The New Source Performance Standard for coal-fired boilers subject to Subpart Da, which commenced operation after May 3, 2011, is an emissions limit of 0.7 lb/MWh (gross) on a 30-boiler operating day basis, which is roughly equivalent to an emissions rate of 0.08 lb/MMBtu. By comparison, EPA's proposed performance expectation of 0.08 lb/MMBtu would drive older EGUs with SCRs installed for different regulatory purposes to a comparable level of performance as a brand-new unit. The new units, however, would be able to incorporate the many advanced features into the original design that would make it far easier to consistently operate at or below 0.08 lb/MMBtu of NOx. This is compounded by the nature of the budget setting and allocation process in the proposed rule, which would require units to operate at even lower emissions rates where the allocations are not representative of the level of projected operation for those units.

5.0 Incorrect Assumptions Result in EPA Greatly Underestimating the Cost per Ton of NOx removed

In the proposal, EPA evaluated EGU NOx cost thresholds and concluded that $1,600 per ton was an appropriate minimum, and $9,600 per ton is an appropriate maximum uniform cost threshold to evaluate for the purpose of quantifying EGU NOx reductions to reduce interstate ozone transport for the 2008 ozone NAAQS. Because these cost thresholds are linked to costs at which EGU NOx mitigation strategies become widely available in each state, EPA considers these cost thresholds as break points in a marginal cost curve at which the most significant step-changes in EGU NOx mitigation are expected.

Because EPA made incorrect assumptions regarding unit retirements and the emission rates SCRs can achieve, its projected cost per ton of NOx removed is also incorrect, thus undermining the basis for the proposal. EPA's assumption that simply changing the catalyst replacement frequency will allow EGUs to achieve improved efficiency is seriously flawed. Catalyst replacement is managed using an ongoing performance evaluation that considers the rate of catalyst deactivation. There are numerous factors that affect deactivation and thus the effective life of a catalyst layer. As mentioned previously, those factors include the amount of time in service, the average load while in service, the presence of catalyst "poisons," erosion from ash particles, catalyst blinding due to the long-term impacts of ammonium bisulfate deposition associated with higher sulfur fuels, flue gas distribution within the SCR, and numerous other considerations. For some units, catalyst life can be as short as two years while much longer for other units depending on operating conditions. Catalyst degradation begins the moment a new layer enters service and continues until that layer is replaced. SCRs typically utilize multiple layers of catalyst and stagger the installation of replacement layers. The practice of staggering the replacement of catalyst layers ensures that at any given time, the SCR has a relative mix of new and used catalyst to perform at a reasonable level. This avoids conditions where an SCR would only achieve a relatively low removal rate, but it also constrains the SCR from consistently achieving its best potential emission reduction rate.[10] Catalyst replacement is a very large capital investment and must be well managed to maximize the value of that investment. Typical replacement cost, including installation for a single layer of a typical three catalyst layer SCR design for a large unit (650 MW), can be approximately $2 to $3 million per layer, depending on whether the SCR can utilize vendor-refurbished catalyst or will require installation of fresh catalyst.[11] Current catalyst management practices are determined by the stringency of the 2016 CSAPR Update rule.

Changing catalyst management practices to achieve enhanced NOx removal performance is a key contribution to any cost-effectiveness analysis. However, EPA's estimated marginal cost of $800 per ton for enhancing SCR operation and more frequent catalyst replacement does not adequately quantify the full scope of changes needed and the costs and achievable emissions reductions across the range of facilities that will be affected by this rule. Duke Energy also points out that EPA's method for portraying marginal costs is not technically accurate. Various sources define marginal cost as the cost necessary to achieve one additional unit of production (or in this case, a ton of NOx removed), which is not what EPA has done either on an aggregate basis for Group 3 or even for individual units. Rather, EPA's approach is better characterized as an "incremental cost," which is the difference in total costs as the result of a change in some activity. Even in this light, EPA's approach is flawed because it aggregates multiple activities. Recognizing that the costs associated with the 2016 CSAPR Update rule are considered "sunk costs," Duke Energy instead recommends that EPA's process should be subdivided into at least two additional increments. The first would recognize that some additional reductions can be realized by the in-place controls such as by increasing ammonia feed alone. These reductions might be considered highly cost-effective, although for many units even increasing the ammonia usage may require upgrade or replacement of the ammonia storage and distribution systems. The second increment only includes the additional reductions achieved by more frequently replacing catalyst and would consider the additional catalyst cost and other required changes, plus the incremental ammonia usage. This second increment of reductions could only be achieved at a much higher cost per ton reduced and would likely not be considered highly cost effective, even potentially being considered overcontrol. Furthermore, more frequent catalyst replacement alone may not be sufficient to achieve consistent performance below 0.10 lb/MMBtu for many units, as EPA itself has noted in its denial of the New York Section 126 petition.[12,13]

Duke Energy also notes that comments filed by the MOG include a report by its technical consultant analyzing EPA's cost-effectiveness determination for catalyst replacement and concludes that the marginal cost per additional ton of NOx removed can be expected to significantly exceed the $1,600 per ton value that EPA has proposed as cost-effective. Duke Energy's review of the potential for more frequent catalyst replacement suggests that the marginal cost could be $4,200 per ton or more for some units, particularly where a unit is already replacing catalyst on a frequent basis to address factors that contribute to rapid catalyst degradation. Attachment 1 contains an example where a large SCR originally designed to maintain a 0.10

---

[10] SCRs are built to accommodate multiple layers of catalyst. Duke Energy has already installed as many layers as possible on its Indiana and Kentucky SCRs; there is no room in which to install additional catalyst. As a result, old catalyst must be removed and replaced with fresh catalyst.

[11] Note that this cost is only for catalyst replacement and does not attempt to quantify the cost of taking additional maintenance outage to install layers more frequently.

[12] "Thus, the fact that some units are operating above 0.10 lb/MMBtu is not indicative that the sources have additional cost-effective emissions reductions available." 84 Fed. Reg. 56,058, 56,092 (Oct. 18, 2019).

[13] While the proposed rule would not require an EGU with SCR to meet an emissions limit of 0.08 lb/MMBtu, the depth of the reductions in state budgets and unit allocations has the effect of requiring EGUs to take steps to reduce emissions far below 0.10 lb/MMBtu and even below the assumed basis of 0.08 lb/MMBtu.

lb/MMBtu emission rate increases its rate of catalyst replacement so that it can achieve a new rate of 0.07 lb/MMBtu. Over an eight-year period two additional layers of catalyst are required. Including incremental catalyst and reagent costs, the additional NOx reductions would cost $4,200 per ton. Duke Energy also notes that MOG also extensively commented on this issue. For these reasons, Duke Energy believes EPA should conclude that there are no further cost-effective reductions from EGUs equipped with SCR and should retain the same technological basis for SCR units (that is, using a typical value of 0.10 lb/MMBtu) as was determined in the 2016 CSAPR Update Rule and as determined reasonable by the *Wisconsin* court.

6.0 EGUs Can Only Achieve a Portion of the Proposed NOx Reductions Through the Operation of Existing Controls in the 2021 Ozone Season.

While EGUs have emitted NOx at a level of total emissions below that of the 2016 CSAPR Update rule, EPA's current proposal represents a considerable reduction in state budgets that would impose large additional operational and cost impacts on EGUs in the new 12-State Group 3 region. SCR-controlled EGUs in the region may have some immediate ability to reduce aggregate emissions below recent levels by increasing ammonia flow and optimizing the installed equipment and process controls. However, there are limits to what sources can accomplish in the roughly six weeks between EPA's scheduled promulgation of the rule and the start of the 2021 ozone season. EPA's proposal is fatally flawed because it assumes that individual units are capable of achieving the proposed emissions rate on a shortened time frame and, if not, EGUs can rely on an effective trading program that has willing sellers and buyers and a sufficient volume of allowances to keep the price commensurate with the marginal cost of control. (Duke Energy disagrees that there will be an effective market and explains this in detail in Section 7.0 below.) Nowhere does the proposal recognize the extent of actions required to make a significant change in the frequency of catalyst replacement such as time for procurement, coordinating the necessary maintenance outages across the generating fleet, tuning of process controls, or the time it takes to install the catalyst. From the lack of analysis in the EPA's proposal, one could incorrectly infer that increasing the rate of catalyst replacement is as easy as bringing the catalyst on-site and simply opening a valve to feed it into the unit faster. An SCR is a massive piece of infrastructure integrated into the boiler exhaust flue gas, and work to replace catalyst requires an outage that will take weeks if not longer to accomplish. Failure to analyze this need is a major omission in the proposal.

Replacing deactivated catalyst with new catalyst requires approximately a year's time due to the time necessary to specify the catalyst design, seek bids from suppliers, select a vendor, and install the catalyst during an outage of sufficient length. There are only four or five major catalyst suppliers that provide SCR catalyst for U.S. application, and the historic "lead time" for new catalyst is nine months to one year. Accordingly, it is unlikely any unit will be able to acquire and install new catalyst, unless such material is already "on-order" for spring 2021 delivery, or the necessary catalyst has been acquired and is being stored. Even if catalyst were available, maintenance outages for all the EGUs need to be staggered. As a result, and counter to the proposal's assumptions, there are few realistic and viable control or efficiency performance options available between now and the date this rule is to become effective. EPA needs to specifically take measures to ensure that any increased requirements are phased in at a rate that can be accomplished by the regulated community. It has not done so with the current proposal. If EPA does adopt a NOx emission rate of less than 0.10 lb/MMBtu for SCRs in the final rule, it needs to use 0.10 lb/MMBtu for at least the first year and then step the rate down in subsequent years. Duke Energy notes and supports the MOG's extensive comments on this issue.

7.0 EPA Compounds an Unreasonable Compliance Deadline by Imposing Restrictions on the Use of Banked Group 2 CSAPR Ozone Season Allowances and Trading Between States.

EPA has created a near-term compliance bottleneck by requiring large-scale reductions beyond the current capabilities of EGUs to comply while essentially allowing no time before the start of the 2021 ozone season for implementation. As has been previously stated, EPA has not conducted any analysis to demonstrate that the proposed requirements are actually achievable. Furthermore, practices such as using unit-specific emission rates below 0.08 lb/MMBtu to set the budgets have severely reduced the potential for sources to generate surplus allowances that can be made available on the market. Finally, EPA's approach of continuing to allocate allowances to retired units while shrinking the state budgets to account for those retirements can cause some of those allowances to sit on the sidelines and not enter the market or be used by a company to forgo more cost-effective reductions so as to conserve capital and O&M expenditures. Given these concerns, Duke Energy believes that for many companies, reliance on the market for a substantial portion of their compliance is not possible because of the restrictions EPA has put on the trading program and the stringency of the proposed program.

Duke Energy is concerned that restricting the use of banked Group 2 CSAPR ozone season NOx allowances will hamper the intent of a market-based program due to insufficient allocations and also create uncertainty because utilities will not know the amount of allowances they will receive for compliance until shortly before the Group 3 program begins.

Not only is EPA proposing to reduce unit allocations, but it is compounding the issue by proposing to restrict the number of banked Group 2 CSAPR ozone season NOx allowances to be converted by the 21% Assurance Level. Comparing previous unit performance to proposed allocations, one can project that all the converted banked allowances will be used for compliance, primarily in the 2021 ozone season, leaving little additional allowances to feed current and future markets when unit allocations are even more stringent. This scenario would create a market that either has no allowances available or that has minimal allowances available for purchase at exorbitant prices and are no longer cost-effective, thereby having a detrimental effect on an efficiently functioning market and compliance. EPA could minimize the impact on allowance markets and provide some degree of flexibility to manage operations by providing a greater number of converted Group 2 allowances to be placed in the final Group 3 bank. Assurance Level provisions would still apply to each state, thus allowing additional banked allowances would not impact the goals of the proposed rule. This would minimize the risk that there may not be a sufficient number of allowances in the market to both cover actual emissions in 2021 and provide some surplus that will be needed going into future years to assure a stable market.

Duke Energy is concerned about the uncertainty of the conversion ratio from Group 2 allowances into Group 3 allowances. EPA's proposed protocol for converting allowances (i.e., giving owners the option to convert Group 2 allocations into Group 3) makes it difficult for EGU owners and operators to plan for how many converted Group 3 allowances they should expect to receive. Creating more uncertainty is the fact that the exact conversion ratio will not be known until shortly before the rule takes effect, thereby not allowing utilities sufficient time to prepare.

Duke Energy is also concerned that this uncertainty will have severe implications for the development of an allowance market. By allowing allowance owners to decide whether or not to move Group 2 allowances into the pool for conversion to Group 3 allowances, utilities would be forced to make speculative decisions on the market value of Group 3 allowances before the market develops. Regulated utilities are averse to speculative decisions and will make decisions based on certainty to the extent possible. Current actions in the Group 2 allowance market, with values remaining low and no significant trades occurring, are an indicator of the uncertainty. Utility allowance managers are simply not in a position at this time to develop compliance plans based on the availability of the allowance market, due both to the uncertainty of whether utilities will reduce emissions enough to provide allowances to the market and the uncertainty of how many allowances will be converted from the allowance bank, which is critical knowledge to determine pricing.

Duke Energy believes that EPA needs to address this bottleneck in the proposal using mechanisms such as:

- Increase the number of banked allowances that can be carried forward from the previous program to provide stability to the allowance market by helping to balance supply and demand when it will be difficult for EGUs to achieve deep reductions in the first year. In addition, EPA should only assess any compliance assurance penalty based on 21% of the current Group 2 state budgets for at least the first one or two years.
- If EPA is to reduce state budgets to reflect EGU retirements to the end of 2024, then it should not allocate allowances to those retired units.
- EPA should consider the concept of a "safety valve" where affected EGUs could purchase additional allowances. A price of $1,600 per ton[14] would highly encourage EGUs to achieve whatever reductions are available, but it reduces risk of not having allowances available on the market given that the market may not fully develop until after the conclusion of the ozone season.[15]

8.0 EPA's Technique for Setting Budgets for Units with Combined Stacks is Incorrect

EPA's methodology to evaluate NOx emissions from common stacks (reporting under 40 C.F.R. § 75.72) that monitor flue gas from both SCR-equipped and non-SCR-equipped units is flawed. EPA's inability to accurately partition emissions for these types of configurations results in an underestimation of state budgets for the years of 2021 through 2024. While Duke Energy does not operate any combined stacks in the Group 3 Region, it is impacted by the effects of this error on the state budgets. As such, Duke Energy supports comments of the Class of '85 Regulatory Response Group, the MOG, the Utility Information Exchange of Kentucky, and the Indiana Electric Association in this matter.

In almost all these common stack incidents EPA's approach did not properly reflect the performance of an SCR-equipped unit. As a result, the NOx emissions assigned to the SCR-equipped units are too high and the "balance" of NOx tons assigned to the non-SCR-equipped units are too low. As a consequence, the NOx budget for SCR-equipped units are allocated

[14] In the proposal this is the price threshold that EPA considers "highly effective."

[15] This alternative compliance payment was used previously by the Agency as part of the program to implement the ozone and particulate matter NAAQS. There, EPA allowed a source facing costs higher than had been anticipated by EPA to pay a set annual amount per ton to fund cost-effective emission reductions. *See* Presidential Documents, "Memorandum of July 16, 1997, Implementation of Revised Air Quality Standards for Ozone and Particulate Matter," 62 Fed. Reg. 38,421 (July 8, 1997).

additional emission reductions for SCR optimization when the units were already operating below the 0.08 lb/MMBtu threshold.

EPA should use the authentic, documented value of NOx emissions for SCR-equipped units (which is much lower than EPA's analysis) and increase the NOx emissions assigned to the non-SCR-equipped unit to reflect the balance of the common stack emissions. Using this methodology will more accurately reflect actual unit operations and result in higher state NOx budgets.

9.0 Unit-Specific Data Errors Identified by Duke Energy

In reviewing materials in the docket, Duke Energy identified some specific errors that EPA must address:

- In its spreadsheet "*SCR_Historical_OS_Rates_Revised_CSAPR_Update_Proposal EPA-HQ-OAR-2020-0272-0012,*" EPA lists historical SCR performance as part of its process for determining the average achievable NOx emission rate. In this spreadsheet EPA incorrectly characterizes the Edwardsport Station (ORIS Code 1004) Units CTG1 & CTG2 as having coal-fired units equipped with an SCR that became operational in 2012. This is incorrect. Edwardsport Units CTG1 & CTG2 are part of an integrated gasification combined cycle (IGCC) unit that burns syngas or natural gas and does not have SCRs installed. As such, they should not be used to characterize coal-fired units with SCR.
- The R. Gallagher Generating Station is scheduled to retire no later than December 31, 2022 in accordance with the consent decree signed with EPA.
- Duke Energy's review found that the former IGCC unit at the former Wabash River Repowering Project (ORIS Code 57842) was converted to a simple cycle combustion turbine operation. Since this conversion, the unit's operation and emissions have declined dramatically. However, EPA's unit-level budget setting process includes data from the time frame when it operated as an IGCC unit skewing the allocation apportionment.

10.0 Duke Energy Supports the Comments Filed by the Class of 85 and the Midwest Ozone Group.

Duke Energy is a member of the Class of '85 and MOG. Both groups have broad memberships, which represent EGUs in many of the states that will be affected by this proposal. The Class of '85 and MOG expended great effort to analyze EPA's proposed CSAPR revision and the underlying analyses and models EPA used to support the draft rule. Those efforts have been hampered by both the very limited time EPA has allowed for commenting on the rule and the excessive delay in receiving adequate modeling data files. Nevertheless, these groups have provided a sound assessment of the key components of EPA's rulemaking effort and have identified serious concerns with the proposed rule. Some of those shared concerns are summarized below. Please refer to the detailed comments filed in the rulemaking docket by these groups.

- EPA has not justified the deep EGU NO_x budget reductions proposed for the 12-state Group 3 region considering the very small benefit to a very small number of downwind nonattainment and maintenance areas EPA identified and the considerable impact the proposed rule will have on EGUs.
- EPA's approach to determining "maintenance" areas is inappropriate and inconsistent with its own methods, and results in faulty conclusions linking upwind states to downwind

maintenance problems that will not exist. EPA itself has even concluded through its own modeling that each of those areas where monitored ozone levels are below the 2008 Ozone NAAQS will continue to be so through 2025. Even if such areas were appropriately labeled as "maintenance," EPA cannot justify the required stringent emissions reductions from the states it says are linked to maintenance areas. States linked solely to downwind maintenance-only receptors should be required only to ensure that their contributions to ozone concentrations at those receptors do not increase.

- MOG through its technical modeling consultant has identified serious flaws or inaccuracies in how EPA ran its models that predict how ozone is formed.
- MOG through its technical engineering consultant has identified serious flaws and inaccuracies with EPA's assessment of the capabilities and cost effectiveness of the measures EPA is including as the basis for reductions in the state budgets.
- The Clean Air Act requires EPA to consider the effects of local emissions and available local emission reductions before determining what amount of emission reductions from upwind states may be required to address interstate transport.

11.0 Conclusion

As described in detail above, Duke Energy has the following concerns and recommendations regarding the proposed rule and asks that EPA address these in the final rulemaking.

Concerns:

- EPA has not provided an appropriate demonstration that the 12 states in the proposed Group 3 region are having a significant impact on downwind nonattainment or maintenance areas in 2021.
- EPA has not demonstrated that the proposed budgets are based on application of cost-effective controls because the proposal overstates the capability of EGUs in the Group 3 region to achieve significantly lower NOx emissions rates and how quickly such changes can be implemented, and because EPA has not provided any meaningful analysis of the contributions and potential control capabilities of non-EGU sources.
- EPA's methodology to determine state NOx budgets and unit allocations places a heavy burden on EGUs in the 12-state Group 3 region forcing sources to make even deeper reductions than EPA claims is immediately achievable, reduce the level of operation shifting generation to other sources within or outside of the region, and/or lean heavily on an allowance market that is expected to be very volatile and uncertain particularly in the first year of the program.

Recommendations:

- Duke Energy recommends that EPA review and adopt the conclusions by the MOG and its technical modeling consultant and conclude that the proposed revisions requiring further reductions from EGUs in the 12-state region are not required. (Such a conclusion based on consideration of properly performed modeling for the 2021 attainment deadline would be consistent with and fully meet the obligation under the *Wisconsin* decision remanding the CSAPR Update Rule.)

- Duke Energy recommends that EPA retain the technical basis for the reasonably achievable capability of coal-fired EGUs equipped with SCR at a NOx emissions rate of 0.10 lb/MMBtu.
- If EPA issues a final rule that incorporates budgets based on an SCR emissions rate more stringent than 0.10 lb/MMBtu, it must provide additional time or flexibility to allow EGUs to make necessary changes to achieve improved performance.
- Duke Energy recommends that EPA base state NOx budgets on a multi-year analysis rather than rely on a single year (2019 or 2020) to assure that budgets include sufficient flexibility and are not unduly impacted by short-term variability at either the individual unit or state level. An appropriate averaging period would be, for example, the highest three-year average for the period 2017-2020.
- Duke Energy recommends that allocations of the state budget should be determined on the same basis as the budget, where the same average heat input would be used for allocating the budget to units as was used to set the budget.
- Duke Energy can support EPA's long-standing policy for allowing retired units to retain their share of a state's NOx budget for some period of time provided that when retired units are no longer used for determining the size of the state budget, the allocation to retired units ceases. The inequity in the proposed rule (requiring that remaining operational units are subject to more stringent control simply due to retirement of other units) must be addressed.

Attachment 1

SCR Accelerated Catalyst Replacement Example

Inlet Emissions Rate	0.67	lb/MMBtu
Outlet Emissions Rate (SCR Original design)	0.1	lb/MMBtu
Original Design Removal Efficiency	85%	
Accelerated Catalyst Replacement Emissions Rate	0.07	lb/MMBtu
Accelerated Catalyst Replacement Design Efficiency	90%	
Max Heat Input	5893	MMBtu/hr.
Assumed Capacity Factor	46.7%	(EPA)
Operating Hours per Ozone Season	3672	hours
Total NOx - Current Plan	505	tons
Total NOx - Enhanced Plan	337	tons
NOx Reduced/year	168	tons
NOx Total for 8-Year Cycle	1,347	tons over eight-year cycle
Catalyst Cost	$2,500,000	per layer, installed
Number of additional layers required	2	over an eight-year cycle
Reagent cost	$500	per ton of NOx removed (EPA)
Incremental catalyst Cost	$5,000,000	over an eight-year cycle
Incremental reagent Cost	$673,749	over an eight-year cycle
Total cost	$5,673,749	over an eight-year cycle
Incremental NOx removal cost	$4,211	per ton reduced

Notes:

-Example is a composite of similar sized bituminous fired, SCR controlled EGUs

-It is assumed that current catalyst practices are designed to maintain a 0.10 lb/MMBtu outlet emission rate and that units with lower inlet NOx would still need to increase catalyst replacements at this rate