Technical Comments on the

Environmental Protection Agency (EPA) Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS

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1. Summary

This document presents a critique of the technical analysis conducted by the Environmental Protection Agency (EPA) supporting the feasibility and cost for the additional NOx controls proposed by the Revised CSAPR Update, and also provides comments on specific topics as solicited by EPA. A summary ordered by six categories is presented as follows.

Methodology Critique

Five flaws in EPA's Methodology are identified. EPA's analysis is based on the generating unit population in the original 22-state CSAPR region, which differs from the population of affected units in the 12-states that are the subject of this action. The 22-state database contains a much smaller fraction of boilers designed to fire bituminous coal, resulting in post-SCR NOx emission rates that are not representative of the 12-state region. Most notably, EPA does not calculate the *marginal cost* per incremental ton of NOx removed, but rather the total cost for NOx reduction from boiler exit values to the third-best ozone season NOx rate. Also, the methodology does not correctly estimate catalyst replacement costs – EPA does not account for the non-linear increase in catalyst volume required for NOx removal beyond 80%, nor the adjustment for PRB coals.

An alternative cost evaluation is conducted to supplement EPA's assessment to rectify these shortcomings. This alternative analysis addresses the *incremental* cost of lowering NOx from the third-lowest ozone season rate to EPA's target of 0.08 lbs/MBtu with margin and considers the 12-state region that is the subject of this action. The results determine the marginal cost for the incremental NOx removal for the 90th percentile of units in the inventory – the same threshold adopted by EPA. The results of our analysis show these costs are $2,816/ton, representing a 75% premium compared to EPA's evaluation.

Combustion Control Capability

EPA's projection of NOx emission rates achievable with combustion controls is flawed as it does not account for the role of coal rank and boiler design. Regarding the latter, results are biased to reflect newer units with a boiler design feature (Burner Zone Liberation Rate) that promotes low NOx conditions that many existing boilers cannot replicate. EPA cites low NOx emission rates to be broadly achievable – claiming 148 and 105 units capable of achieving the emission rates of 0.1549 and 0.1390 lbs/MBtu, for wall-fired and tangential-fired boilers, respectively. These data are not corroborated by authentic industry experience; 2016 Clean Air Markets Data (CAMD) shows only 6 and 26 units were capable of achieving these rates for wall-fired and tangential-fired boilers, respectively.

Key Schedule Information

EPA solicited comments addressing the schedule for maintenance activities to improve existing SCR performance, retrofit of new SCR process equipment, and retrofit combustion controls. For units with existing SCR process equipment, four categories of SCR O&M activities are routinely

conducted to improve performance – tuning of the SCR process, repair of cleaning devices, manual cleaning of catalyst, and accelerated replacement of existing catalyst. There will be not be adequate time and personnel resources available to implement these actions between the CSAPR rule finalization date and the 2021 ozone season. Based on historical practice, it is likely only 10-20% of the boiler inventory within the 12-state region will be able to execute one or more of these actions. This will inhibit the ability of many units to meet a 2021 ozone season NOx rate of 0.08 lbs/MBtu.

The time required to install SCR at existing generating units, with a few exceptions, exceeds 39 months. It will not be possible to broadly retrofit SCR NOx controls for operating units in the 2022 ozone season. The time period for retrofit of advanced combustion controls is at least 13 and up to 19 months. Consequently, it will not be feasible to retrofit improved combustion controls for the 2021 ozone season.

Large Non-EGU Generators

Large non-EGU generators confront the same challenges as EGUs – essentially all affected units will have to retrofit some form of combustion control technology. In one example, an aluminum production facility's coal-fired units have already adopted one of the most recent versions of low NOx burners. Given the compact arrangement of that boiler the next-generation low NOx burner does not appear feasible due to flame impingement.

Commons Stack Units and State NOx Budgets

The States of Kentucky and Indiana feature numerous "common stack" generating stations in which the stack gas from an SCR-equipped unit is blended with that of a unit not equipped with SCR. EPA's Part 75 data reporting conventions do not ascribe accurate emissions to each individual unit. In developing state emissions budgets, EPA incorrectly attributes incorrect NOx emission rates to both the SCR-equipped unit and the non-SCR unit, lowering the NOx budget for a state. Correcting EPA's NOx emission rates for both the SCR- and non-SCR-equipped units results in higher state NOx budgets that more accurately account for the existing conditions. More representative NOx emissions data reflects on the dilemma and inability to install controls within the implementation period for this program.

This report is comprised of six sections. Section 2 describes the flaws in EPA's evaluation of cost and NOx control capability, while Section 3 describes analogous flaws in the assessment of combustion control capability. Section 4 presents a description of the schedule for key events to improve SCR performance, as well as for retrofit of SCR process equipment and combustion controls. Section 5 discusses two examples that reflect non-EGU operation, and Section 6 summarizes the common stack issues and presents revised state NOx budgets for Kentucky and Indiana.

2. Flaws in EPA's SCR Evaluation Methodology

Section 2 addresses EPA's evaluation methodology for SCR, identifying flaws that compromise the validity of the results.

EPA's evaluation of the cost for additional NOx control as proposed by the Revised CSAPR Update employs a database constructed for the initial CSAPR evaluation, which includes 22 states - almost twice the scope of the 12-state region evaluated for this proposed Revised CSAPR Update. EPA also uses control technology operating costs from supporting information in the February 2020 CSAPR IPM modeling. Fundamental process features such as SCR reactor design, the catalyst volume in inventory, coal composition, and the "host" boiler design – of course could not be considered in this report. Consequently, this analysis is confined to a "macro" level and provides results that are approximate.

There are at five shortcomings in EPA's analysis. First, the scope of the present action addresses 12 states, which compared to the initial 22 CSAPR states exhibit different characteristics that affect SCR design and operation. Second, EPA under-estimates boiler exit NOx emissions of many units which affects operating cost as higher NOx removal is necessary. Third, EPA estimates the total cost per ton of NOx reduction from the boiler exit as opposed to the marginal cost to provide additional NOx reduction from recent controlled emission rates. Fourth, and relevant to determining marginal cost, EPA determines the variable operating and maintenance cost for catalyst management using IPM cost relationships, which do not adequately reflect the cost to achieve extremely high NOx removal rates. Fifth, EPA did not employ an IPM-advised adjustment for subbituminous coals, and by doing so under-predicted catalyst volume and the relevant replacement cost by 17%.

These technical comments address SCR - not SNCR – as the latter is not anticipated to be a significant contributor in actions pursuant to a Revised CSAPR Update. SNCR can be a useful control option, but the technology faces numerous challenges, particularly for large utility boiler operating under highly variable load conditions. NOx removal with SNCR in utility boilers is reported as capable of 20-40%,[1] but large utility boilers in cycling duty can be restricted to 15-25% NOx reduction.[2] The sensitivity of the optimal "temperature window" for injection and uniform mixing of urea reagent requires a degree of injection and process control that is difficult to maintain over large distances, with variable process conditions. As gas flow conditions change – prompted by a change in combustion conditions, varying load, accumulation of deposits on heat removal surfaces - the temperature window can shift. Urea reagent can penetrate and remain as ammonia or be oxidized to NOx. The generation of high residual ammonia leads to ammonia bisulfate fouling of the air heater.

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[1] S. Johnson, Care and Feeding of SNCR Systems, NOx Combustion Roundtable, February, 2009, Cleveland, OH.

[2] See, for example, data for Ft. Martin in Worksheet "new SNCR" in EPA-HQ-OAR-2020-0272-0006.

EPA should also be aware the reporting via EIA Form 860 of SNCR capability does not necessarily constitute an accurate description – many installations are simplified systems with one injection level intended for NOx trimming. These single-level injection systems are prone to be ineffective as the furnace temperature window shifts. Consequently, SNCR is not anticipated to significantly contribute to the goals of the proposed Revised CSAPR Update for the bulk of utility boilers.

Each of these flaws is addressed in more detail as follows.

2.1 Scope: 22 versus 12 State Database

EPA's evaluation employs a database describing the complete 22-state CSAPR region, as reflected in the EPA spreadsheet set forth in the rulemaking docket at EPA-HQ-OAR-2020-0272-0006 (hereafter "006" spreadsheet).[3] The boilers and fuel use that comprise the database dictates the NOx control capability and operating cost for both combustion controls and SCR process equipment. The key features of generating units in the 22-states differ significantly from the affected units in the 12-states that are considered in the proposed rule.

The most notable distinguishing feature when comparing the 22-states from the 12-states is the distribution of boilers firing bituminous vs. subbituminous coal, and the coal sulfur content of these fuels. Figure 1 and 2 compare these characteristics for the 12-state and 22-state regions. Figure 1 presents the fraction of units (as percent basis) that utilize bituminous, subbituminous, lignite, or a blend of bituminous and subbituminous coal. The percent distribution is shown for both the 12-state and the initial 22-state region.

[3] EPA-HQ-OAR-2020-0272-0006.

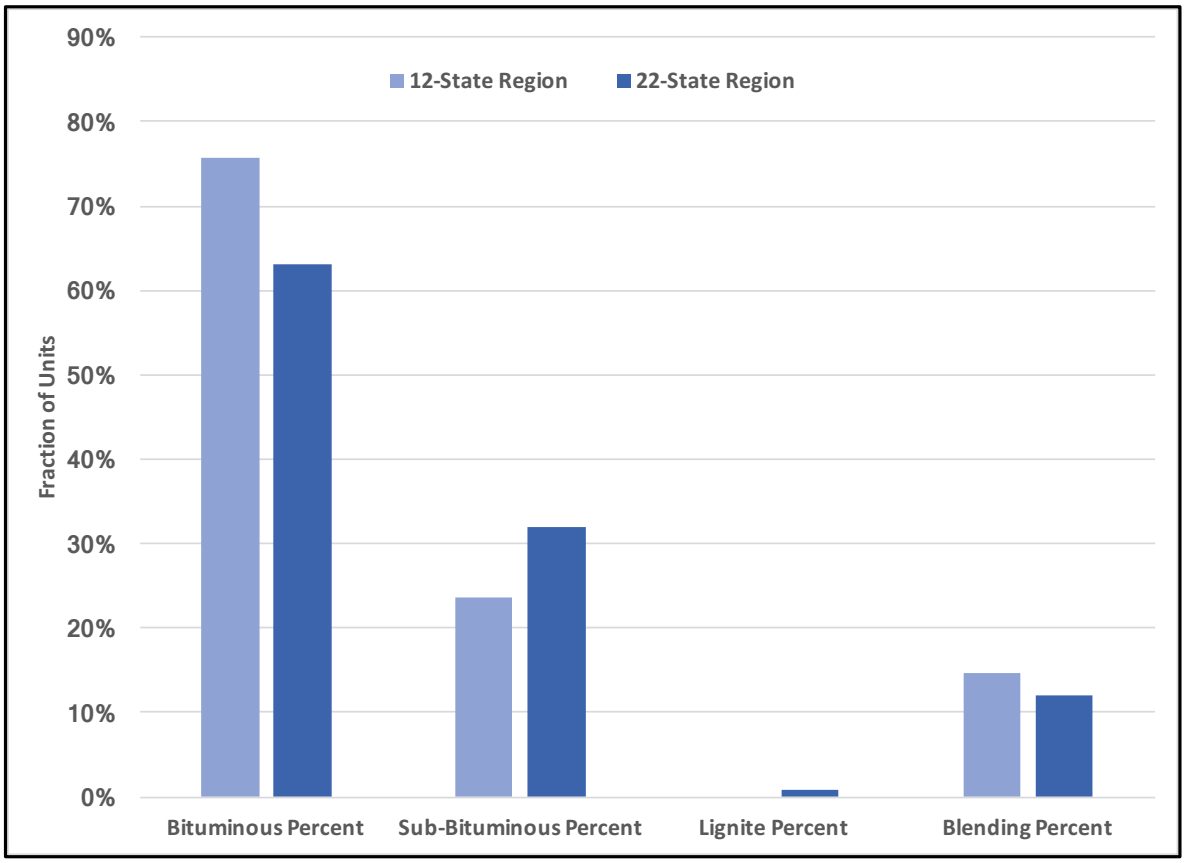

Figure 1. Coal Rank: 12-State versus 22 States in Initial CSPAR Region

Most notable is the significantly higher percentage of boilers firing bituminous coal operating in the 12-state region targeted by EPA in its proposed rule. Bituminous coals generally contain higher sulfur which increases the concentration of sulfur trioxide (SO_3) in the gas stream, affecting catalyst formulation, minimum achievable generating load, and formation of deposits that accumulate on downstream air heater surfaces. Figure 1 shows approximately 77% of units in the 12-state region fire bituminous coal compared to 62% of units in the 22-state region. Conversely, 22% of the units in the 12-state region fire subbituminous coal compared to 32% in the 22-state region.

More striking than the inventory of units firing bituminous coal is the average sulfur content of the coal. Figure 2 presents the distribution of coal sulfur content over the unit population. Notably, the average sulfur content of units in the 12-state region is 2.4% in contrast to the average of 1.8% in the 22-state region. This difference in sulfur content will affect SCR design and operation.

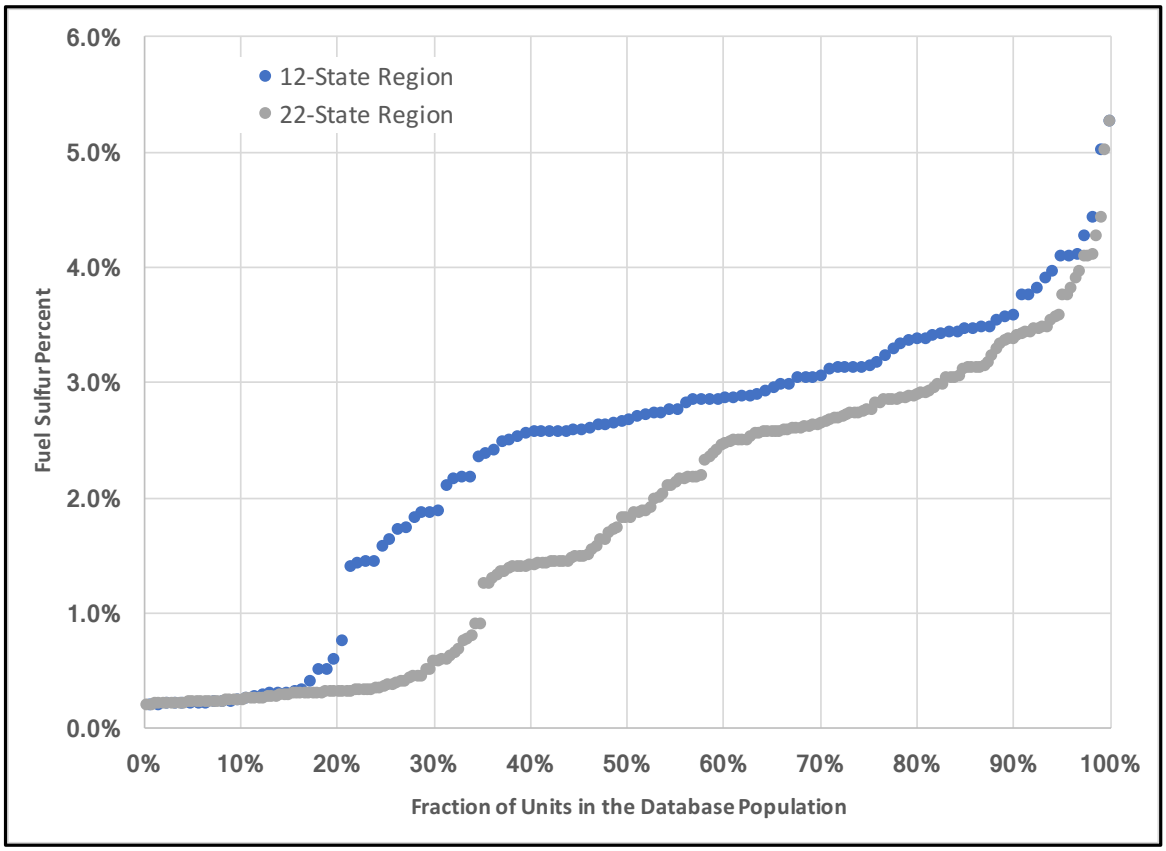

Figure 2. Coal Sulfur Content: 12-States vs. 22 States in Initial CSAPR Region

As an example, sulfur content of 2.4% implies flue gas SO_3 content of 40 ppm, whereas for a coal with sulfur content of 1.1% an SO_3 content of 20 ppm is observed.[4] Higher SO_3 will affect SCR performance and operating cost – the specification of SCR catalyst will likely require lower SO_2 oxidation rates which also can lower activity for NOx removal. As a result, greater catalyst volume is required with higher catalyst management costs. Perhaps more important, the SO_3 content in the flue gas can establish the minimum load at which the unit can operate without catalyst degradation.[5] The consequence of higher sulfur coal-fired units in the inventory is the potential for a greater fraction to be required to bypass the SCR at low load, surrendering a portion of the NOx control capability. There are mitigating actions for this latter impact, but their effectiveness can be uncertain and each imposes additional capital and/or operating cost.[6,7]

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[4] Flue gas sulfur content in SCR-equipped units is determined by oxidation inherently in the boiler and by the SCR process. A fuel sulfur content of 2.4% will generate approximately 2,600 ppm of sulfur dioxide (SO_2) at 4% oxygen (O2). Typically, 1% of SO_2 is oxidized in the boiler to SO_3, with an additional 1% by the SCR catalyst. As a result, 50 ppm of SO_3 can be generated for this sulfur content. In contrast, a unit burning coals with 1.1% sulfur content will be characterized by less than 25 ppm of SO_3.

[5] Vega, E. et. al., Fuel Effect on Boiler and Catalyst Maintenance, NOx and Combustion Roundtable, February 2014, Charlotte, N.C.

[6] Neidig, K., Low Load Operation: A Study of Catalyst MOT and MIT, NOx and Combustion Roundtable, February 2015, Richmond, VA.

[7] Gray, S. et. al., SO_3 Mitigation to Reduce Emissions/Operating Cost, Power Engineering, March 6, 2017.

2.2 Incorrect Boiler Exit NOx Rate

EPA's 0006 spreadsheet calculates NOx removal from EPA's inferred boiler NOx exit rate to meet the 3rd lowest seasonal rate for the period 2009-2019. EPA determined boiler exit NOx rates by reviewing monthly emission averages over the years from 2009 through 2019, focusing on the 7-month non-ozone season presumably without SCR. EPA observed numerous instances in which the inferred boiler exit NOx rate was below not only 0.20 lbs/MBtu but 0.10 lbs/MBtu – suggesting the methodology is flawed.

Figure 3 summaries the boiler exit NOx rates for units in the 122-state region, presented as a cumulative frequency distribution for bituminous and subbituminous coals. Figure 3 shows a notable fraction of units with boiler exit NOx rates below 0.20 lbs/MBtu - for 20% of subbituminous units and 17% of the bituminous units. EPA includes in the analysis only units for which the inferred pre-SCR NOx rate is 0.20 lbs/MBtu or higher.[8] EPA's inferred boiler NOx rate is too low for many units.

The alternative analysis set forth in this report employed a different approach from EPA's assumptions. First, where possible, owners of generating units were contacted to report actual boiler exit NOx emissions. The boiler exit NOx rates for approximately 1/3 of generating units in the 12-state region were updated using this method. Second, data from EPA's CAMD data was "scraped" over a 5-year period, seeking high NOx emission rates that could represent boiler inlet conditions. The time intervals included the single maximum hourly rate, the average of the top 1% and 5% of data, and the threshold for the 95% and 99% rates. This approach used in the analysis contained in this report captured units in start-up or shutdown, or when the SCR is temporarily bypassed, or reagent is not injected (for maintenance or malfunction).

[8] See, EPA Technical Support Document (TSD) footnote #7. *A NOx emission rate at or above 0.2 lb/Btu may be indicative of emissions from units where the SCR is not operating. (Should this footnote be revised to read like footnote 9 with citation to the docket?*

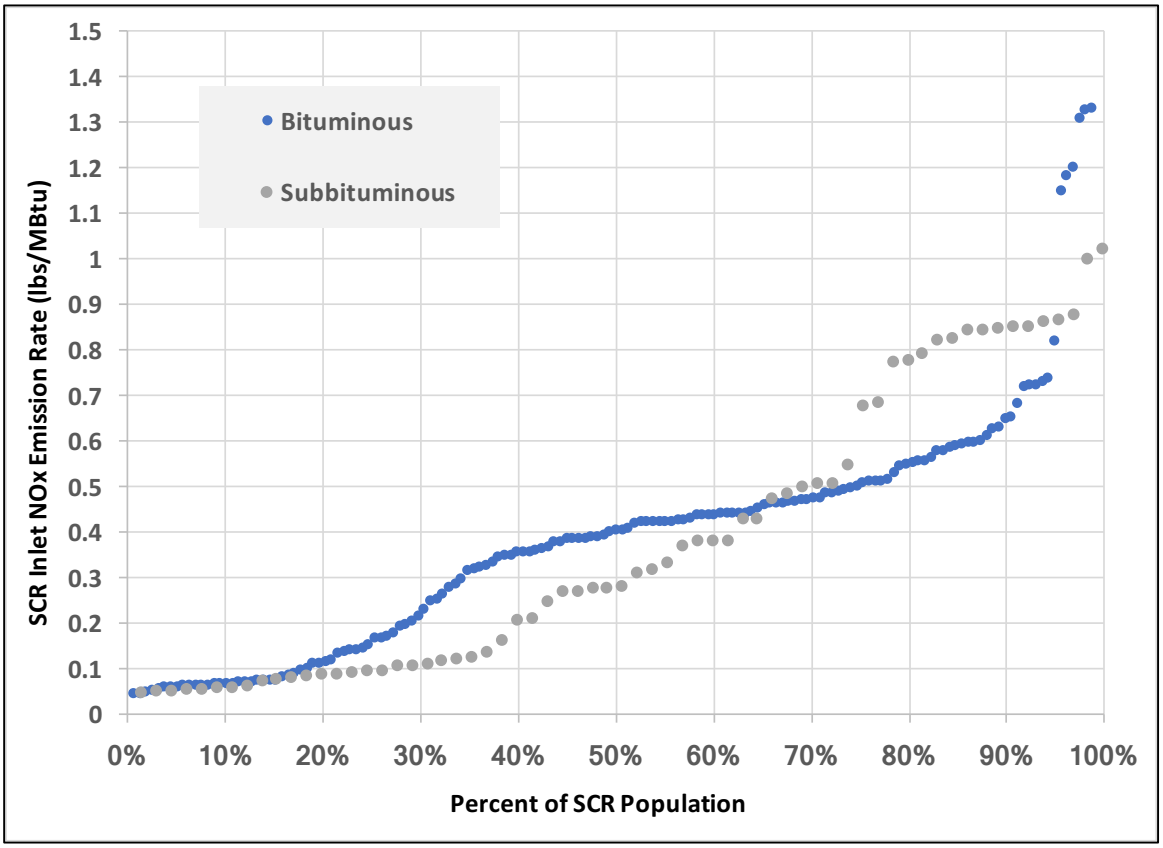

Figure 3. EPA-Inferred Boiler NOx Emission Rates: Bituminous and Subbituminous Coals

Figure 4 set forth below, presents revised boiler exit NOx rates for the 123 generating units in the 12-state region compared to the 223 units in the 22-state region. The "adjusted" approach for this alternative evaluation generates boiler exit NOx rates that are consistent with broad observations, as a consequence slightly elevating the cost to achieve the post SCR controlled NOx emission rate.

2.3 Cost Basis

Two sources in the EPA docket used in this critique and report are the EGU Technical Support Document[9] and the EPA "0006" spreadsheet, most notably worksheet "ex_SCR_3rd_best". Review of these documents – complicated by the absence of a description of the calculation strategy - identified shortcomings in EPA's assessment that prompted this alternative analysis.

[9] *EGU NOx Mitigation Strategies Proposed Rule TSD*, Technical Support Document for the Proposed Revised CSAR Update for the 2008 Ozone Season NAAQS, Docket ID No. EPa-HQ-OAR-2020-0272.

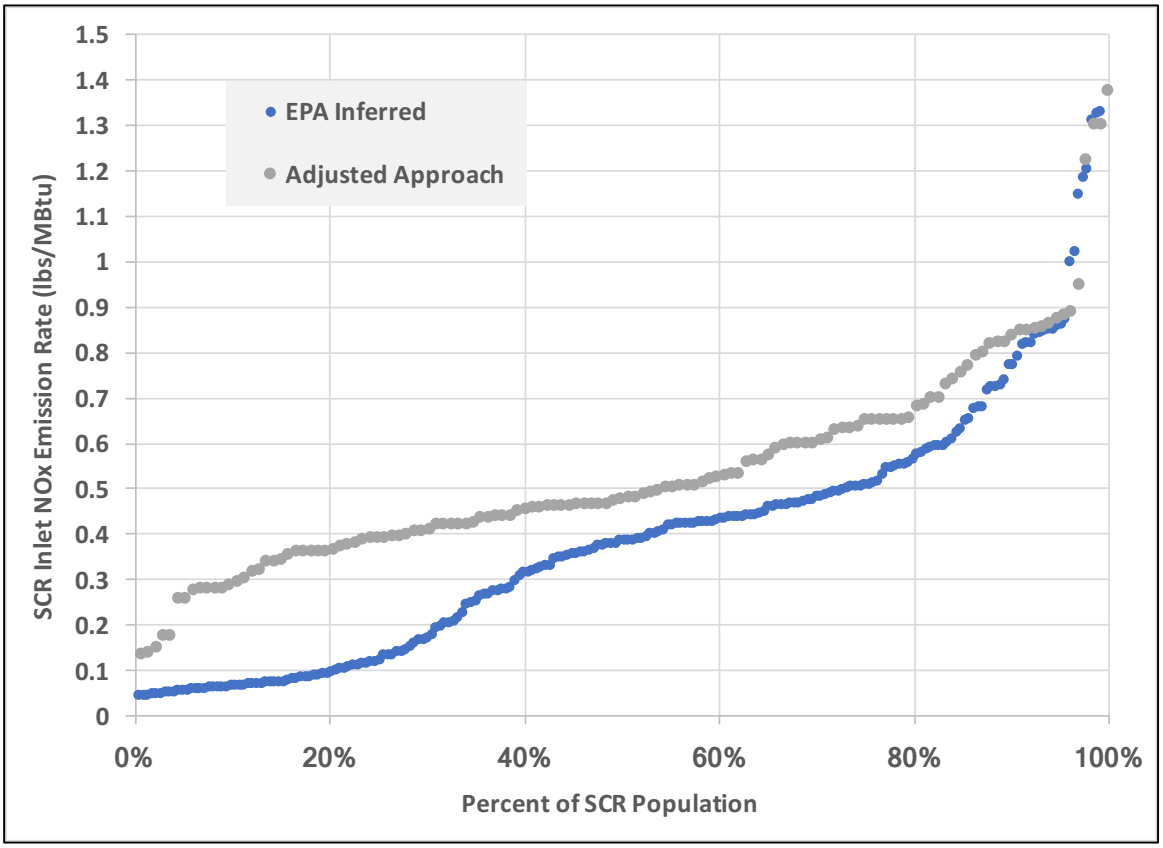

Figure 4. Boiler Exit NOx Emissions: EPA-Inferred vs. "Adjusted" per Industry Input

First, it should be noted the selection of the "third-best" ozone season NOx emission rate from the eleven-year period (2009-2019) is arbitrary. EPA also calculated a "third-best" rate for the shorter period of 2013-2019,[10] better representing the future operating profile of generating units due to increased competition from gas-fired units and renewables. This shorter period is characterized by both higher variability and an increase in the "third-best" rate from 0.080 to 0.091 lbs/MBtu.

In addition to arbitrary reference data, EPA's treatment of cost is characterized by several flaws - ignoring incremental cost, failing to apply the IPM-derived adjustment for subbituminous coal, and improperly determining variable catalyst maintenance costs for high NOx reductions. Each of these flaws is addressed subsequently.

2.3.1 Use of Total Not Incremental Cost

EPA's threshold cost of $1,600/ton is derived from the 90th percentile of operations and maintenance (O&M) cost for returning an SCR to full operation – specifically, the $1,616/ton value from the column "OS total VOM+FOM" (Column CJ) in "ex_SCR_3rd_best" of the "006" spreadsheet. This column is the sum of the Fixed O&M (Column CI), the Urea Cost (CB),

[10] See EPA-HQ-OAR-2020-0272-0012.

Catalyst Replacement and Disposal cost (CC), and Other O&M (CD). However, this methodology is not what is described in the EGU TSD on Page 3:

> *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.*

The project team that prepared this report cannot find evidence the methodology as described was carried out. Rather, EPA reports the cost of NOx removal ($/ton basis) to achieve the third-lowest ozone season rate, starting from inferred boiler exit NOx rate. The methodology pursued by EPA adds Fixed O&M to the total cost (not the incremental cost) of NOx reduction; thus EPA reports a higher value of the wrong cost.

One consequence of the methodology as practiced in the "0006" spreadsheet – using equations from the IPM source document - is a near-linearity in cost with respect to NOx removal. Rarely are control technology costs linear as the most stringent performance is approached. As shown in the following subsection, EPA's variable operations and maintenance (O&M) cost for catalyst management and disposal does not reflect the non-linear increase to elevate NOx removal efficiency from 80% to 90%.

2.3.2 Catalyst Management Cost

The variable operating cost for catalyst imbedded in the IPM model[11] and used by EPA enables input of target NOx removal – but there is no documentation of how the relationship is constructed. Without knowing the input conditions, it is not possible to assign confidence to the impact of small changes in demand – particularly at the boundary of performance, such as 80% to 90%.

A more authentic estimate of the increase in catalyst volume to achieve 90% NOx reduction can be derived from catalyst supplier estimates. Figure 5 describes the design from one supplier submitted in a competitive catalyst bid contrasting 80% versus 90% NOx removal. Figure 5 shows 30% more reactor "potential" is required to achieve a 90% design; which for the same catalyst composition and geometry this implies a 30% increase in catalyst volume.

This disproportionate increase in catalyst volume as NOx reduction escalates from 80 to 90% is consistent with design and operating experience. Among the factors that limit SCR NOx reduction is the increase in "unmixedness" of the inlet NH_3 and NOx entering the last stages of the process.[12] This distortion in inlet conditions and other factors can make the additional catalyst surface requirement to be non-linear with NOx reduction, as removal approaches 90%.

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[11] EPA SCR Retrofit Cost tool available at https://www.epa.gov/airmarkets/retrofit-cost-analyzer.

[12] Specifically, the relative uniformity of injected NH_3 and NOx can increase from a 5% RMS (root-mean-square) basis at the inlet of the first layer to 20% or more entering the last layer as both NH_3 and NOx are consumed in equal proportions.

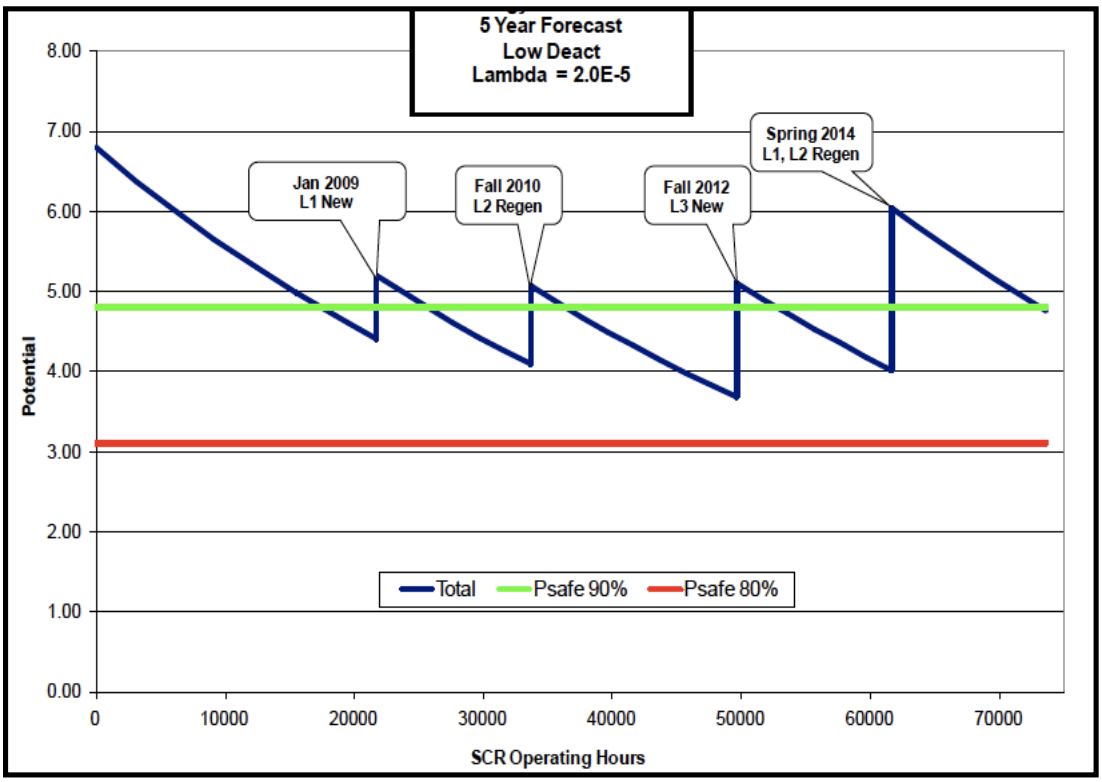

Figure 5. SCR Process Reactor Potential to Maintain 90% vs. 80% NOx Removal

For this evaluation, the IPM-derived relationship describing variable operating cost is revised to reflect the non-linear increase in catalyst volume to achieve 90% NOx reduction. As derived from the relationships developed for the IPM, the catalyst variable O&M to achieve 90% NOx removal increases by 8.7% from the value required for 80% NOx removal.[13] The data in Figure 5 suggests the increase in catalyst volume to elevate NOx removal from 80% to 90% is at least 30%. The 30% increase is inferred by comparing values of a basic SCR reactor design variable – the Reactor Potential (denoted as "potential" on the left-hand vertical axis). The increase in catalyst volume to elevate a reactor designed for 80% NOx reduction to 90% NOx is reflected by the ratio of "PSafe 90%" to "PSafe80%". The values of this dimensionless metric are 4.82 for 90% compared to 3.2 for 80% – an increase of 50%. A value of a 30% premium is used for these calculations.[14]

2.3.3 Subbituminous Factor Ignored

EPA's failure to apply the IPM-derived adjustment to the catalyst variable O&M costs contained by the IPM model for subbituminous coal results in flawed conclusions

[13] The Variable O&M for catalyst replacement and disposal contains a factor "L"; the value described by the ratio of targeted NOx normalized by 80%. For 90% SCR NOx removal, the value "L" is 90/80, which when raised to an exponent of 0.71 is 8.7%.

[14] Regarding the Variable O&M term for catalyst replacement and disposal, the exponent for the value "L" when NOx removal is 80% or higher is 3.0 instead of the IPM-derived value of 0.71.

EPA's error for the initial inventory applies only to subbituminous coal. Although this represents less than 25% of the inventory of the 12-states, it is still a significant contribution to cost. According to the cost relationship derived for the IPM, specification of subbituminous coal should increase the cost for catalyst replacement by 17% over the costs experienced with bituminous coals.[15]

2.4 Revised Results – Corrections to EPA's Flawed Cost Analysis

The calculation of inferred cost per ton to lower NOx emissions from 2019 values to reliably achieve 0.08 lbs/MBtu has been revised in this report to redress the shortcomings identified in this section. These are:

- Considering the true incremental cost to achieve 0.08 lbs/MBtu, from the "third-best" ozone season NOx rate, targeting a rate of 0.07 lbs/MBtu to provide margin.
- Refinement of boiler exit NOx emission rates, as previously discussed in Subsection 2.2.,
- Use of the adjusted catalyst replacement cost relationship, maintaining the form as obtained from the IPM documentation for NOx reductions of less than 80%, but elevating catalyst management costs to reflect the 30% increase from 80% to 90%. Also, including the proper catalyst volume adjustment factor for subbituminous coal.

Table 1 reports the incremental cost estimated to reduce NOx from the third-seasonal lowest rate to 0.065 lbs/MBtu, the latter value providing an operating margin. Table 1 summarizes the "N" or number of variables in the analysis, the mean value, the threshold values for the 90th and 95th percentile of cost incurred, and the maximum value.

Table 1. Summary of Cost to Achieve 0.08 lbs/MBtu (With Margin)

Cost Metric	N	Mean ($/ton)	90th Percentile ($/ton)	95th Percentile ($/ton)	Maximum ($/ton)
Incremental	66	1,685	2,816	4,382	10,035

The threshold incremental cost for the 90th percentile of $2,816 per ton exceeds the $1,600 per ton implied by EPA by 75%.

The incremental costs presented in Table 1 exceed the costs reported by EPA for several reasons. As stated previously, EPA did not consider incremental costs, and the methodology practiced in the 0006 spreadsheet does not comport with the methodology described in the EGU TSD.

Most notably, as illustrated in Figures 1-4, the 123 units in the 12-states that are the subject of the alternative evaluation differ from the 223 units in the 22-states in several attributes. The

[15] The Variable O&M for catalyst replacement and disposal is described by the relationship: = (0.4*(G^2.9)*(L^0.71)*S)/(8760). For bituminous coal the value of "G" is "1" while for subbituminous coal the value is "1.05"; the latter raised by the exponent of 2.9 creates a factor of 1.152.

boiler NOx exit values from many of these units are higher, as are the operating and maintenance costs for reagent supply and catalyst replacement. The corrected non-linear values of catalyst management cost also contribute to higher cost per ton of NOx removed.

EPA's results are compromised for these reasons.

3. Critique: Combustion Control Capability

EPA significantly over-estimates the capability of combustion controls to achieve extremely low NOx emissions, and does not conduct an authentic assessment of the cost for this control technology.

Specifically, EPA notes in the EGU TSD:[16]

> *EPA estimated the average 2016 ozone season NOx emission rates for all such units by firing type. For dry bottom wall-fired coal boilers with "Low NOx Burner" and "Overfire", there were 148 units averaging 0.1549 lb/mmBtu. For tangentially-fired coal boilers with "Low NOx Burner" and "Closed-coupled/Separated OFA", there were 105 units averaging 0.1390 lb/mmBtu.*

The number of boilers actually achieving these NOx emission rates is a fraction of the numbers implied by this passage. Significantly, EPA does not acknowledge the fuel-specific and boiler-specific constraints to be considered in generalizing NOx emission rates from a small subset of boilers to the national inventory. EPA did not conduct a detailed cost evaluation of combustion controls, using actual cost projected for the inventory of boilers affected by this rulemaking; rather total costs (not incremental costs) for an "illustrative unit"[17] are cited to support the threshold of $1,600/ton.

Each of these issues are addressed subsequently.

3.1 Prediction vs. Measured NOx Emission Rates

EPA implies in their assumption that 148 and 105 units achieve NOx emission rates of 0.1549 and 0.1390 lbs/MBtu, respectively, based on CAMD data. The number of units cited by EPA that meet the claimed NOx emission rates cannot be verified.

Table 1 of the EGU TSD states that 59 units in 2019 with *Low NOx Burner Technology w/Closed-Coupled/Separated OFA" (LNC3)* could achieve an ozone season NOx emission rate of 0.147 lb/MBtu, based on CAMD data. We could not corroborate these statements based on a review of the same CAMD data for the 2016 ozone season operation. This discrepancy is described for wall-fired and tangential-fired boilers as follows.

[16] EGU TSD, page 11.
[17] Ibid, page 10 and footnote #19.

Dry-Bottom, Wall-Fired Boilers. The CAMD 2016 ozone season data reveals only six coal-fired, dry-bottom, wall-fired units equipped with *Low NOx Burners and Overfire Air* averaged NOx emissions below 0.1549 lb/MBtu (not including units that installed additional controls, co-fired other fuels, have retired or had a capacity below 25 MW). None of these six units burned bituminous coal. A second source – the NEEDS 617 database - does not support EPA's claims. NEEDs reports three bituminous-fired units that are wall-fired and equipped with *Low NOx Burner and Overfire Air*. These three units averaged NOx emission rates between 0.24-0.31 lb/MBtu in the 2016 ozone season.

Prior EPA publications do not support EPA's assumptions. An early EPA Alternative Control Techniques (ACT) document[18] reported 50% NOx reductions as achievable from wall-fired units burning bituminous coal, with uncontrolled NOx emission rates averaging 0.9 lbs/MBtu, implying a typical controlled emissions rate of 0.45 lbs/MBtu as feasible. Although this NOx control technology has evolved there are no data that support *Low NOx Burners and Overfire Air* applied to bituminous firing can achieve on average a NOx emissions rate of 0.1549 lbs/MBtu.

Tangential-Fired Boilers. Similarly, CAMD data for the 2016 ozone season reveals there were 26 tangential-fired boilers that emitted NOx at an average rate of 0.139 lb/MBtu (not including units that installed additional controls, co-fired other fuels, have retired or had a capacity below 25 MW). None of these units burned bituminous coal. The NEEDS 617 database reports 32 tangential-fired units (not scheduled for retirement) are equipped with LNCIII technology of which five burn bituminous coal – none of which emit NOx at a rate of 0.139 lbs/MBtu or less.

The NOx reduction of LNCIII technology is highly dependent upon fuel rank and unit design (Subpart D or Da). EPA's ACT document reports results from a pre-NSPS boiler (bituminous-fired Lansing Smith 2) demonstrating NOx reduction by LNCFS II of 40 to 50 percent, while LNCFS III reduced NOx by 50 percent.[19] EPA's ACT reference cites an average uncontrolled NOx rate of 0.7 lb NOx/MMBtu for tangential-fired units burning bituminous coal, which if reduced by 50% via LNCIII implies a controlled NOx rate of 0.35 lb/MMBtu. EPA's implied 0.139 lb/MMBtu NOx emission rate for tangential-fired boiler suggests a NOx removal rate of 80%. Although LNCII and LNCIII technology have evolved, there is no data that suggests a LNCII or LNCIII applied to bituminous coals can achieve these NOx emissions.

The basis of this discrepancy appears to be EPA's improper extrapolation of NOx data. Table 1 of the TSD EGU reports NOx emission rates observed in 2019 that serve as the basis for EPA's projection – the rate of 0.159 lbs/MBtu is associated with *Low NOx Burner Technology w/ Separated OFA* and the rate of 0.147 lbs/MBtu is associated with *Low NOx Burner Technology w/ Closed-Coupled/Separated OFA*. EPA does not disclose the specific units which could be of recent vintage and thus atypical of the national inventory. This prospect is suggested by

[18] *Alternative Control Techniques Document – NOx emissions from Utility Boilers*, Report EPA-453/R-94—023, March 1994. Hereafter EPA ACT. See Table 4-2, which reports wall-fired NOx emissions to range between 0.6 and 1.2 lbs/MBtu, and page 5-54.
[19] Ibid, page 5-50.

relatively small "Number of Unit-Years" in 2019.[20] In summary, EPA's extrapolation if based on recent new units does not represent the universe of sources addressed in its proposed rule.

3.2 Limited Basis to Generalize Results

EPA does not account for the significant differences in coal composition known to affect the performance of combustion controls, or the design "vintage" of the boiler that affects NOx emissions. Each of these factors is addressed below:

3.2.1 Fuel Composition

The composition of fuel drives NOx control capability with subbituminous coals – most notably those from Wyoming's Powder River Basin (PRB)- produce inherently lower NOx emissions. The key coal features are nitrogen content and reactivity – the latter reflected in the *Volatile Matter* and *Fixed Carbon* characteristics of the fuel. PRB coal features high reactivity which enables nitrogen within the fuel to rapidly evolve from solid to gas phase and experience oxygen-deficient conditions which prompt the reaction paths to molecular nitrogen.[21]

NOx control capability is greatest when liberated fuel-bound nitrogen is exposed to oxygen-deficient conditions for the longest residence time. For this criteria PRB coal presents a second advantage in maximizing oxygen-deficient conditions while avoiding boiler watertube corrosion. However, the same low NOx conditions when created for bituminous coals generate sulfur-containing, corrosion-inducing species. Selecting proper materials for boiler walls can limit corrosion damage, but it is still advised that "minimizing substoichiometry" (e.g. creating oxygen-deficient conditions) limits damage to boiler tube walls.[22] In concept, limiting coal sulfur and chlorine content can safely achieve lower NOx rates, but this practice restricts the use of high sulfur coal.

The implications of these observations are clear – PRB coal with extremely low sulfur combined with high alkaline content minimizes the production of corrosive species and enables PRB-fired burners to exploit low NOx conditions, but such options are not available to the general population of units in the 12-state region. Therefore, EPA's failure to distinguish characteristics of coal used in its analyses results in a generalization that distorts its conclusions.

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[20] EGU TSD, Table 1, page 9. Note the decrease in the "Number of Unit Years" as described for the time periods of 2003-2008, 2009-2018, and 2019. The minimal number of unit years in 2019 suggest that recent units entering commercial service are represented, which are atypical of the national inventory and the affected units in the rulemaking.

[21] *Retrofit NOx Controls for Coal-Fired Utility Boilers*: A Technical Assessment Guide for Meeting the Requirements of the 1990 Clean Air Act Amendments, EPRI Report TR-102071, 1994. See Box 7-1. Also see Paschedag, A., *Combustion and NOx 101*, Advanced Burner Technologies for the 2008 WPCA Roundtable, February 2008, Richmond, VA.

[22] Kalmanovitch, D., *Waterwall Corrosion Due to Low NOx Combustion – Material Choices*, presented to the 2007 NOx Round Table and Expo, February 2007, Cincinnati, OH

3.2.2 Boiler Design

Equally important to the role of fuel composition is boiler design - perhaps most important is the heat release intensity and furnace geometry. These two features are related; a generous furnace sizing allows typically elongated low NOx flames to not impede heat transfer or prompt flame impingement. Also, generous furnace sizing presents lower heat release intensity, a design feature quantified as the Burner Zone Liberation Rate (BZLR) which each boiler designer interprets and defines differently.

Figure 6 presents a general boiler layout used to define the BZLR for the four major boiler suppliers.[23] Prior to concerns for NOx reduction, BZLR was selected almost exclusively to maximize fuel utilization (e.g. achieve minimal carbon burnout) and avoid furnace corrosion while minimizing boiler footprint – a key factor that determines capital cost. NOx control mandates changed boiler design criteria – BZLR was specified to support controlling NOx emissions.[24] This change in BZLR was prompted by the need to lower flame temperature to minimize thermal NOx and provide space for the extended length, low NOx burners. The most recent boiler designs employ relatively low BZLR to achieve these NOx rates.

[23] Retrofit of NOx Controls for Coal-fired Utility Boilers, EPRI Report for Research Project 2916-7 December 1993. See Figure 3-8.

[24] J. Vatsky, Development and Field Operation of the Controlled Flow Split Flame Burner, Proceedings of the 1981 Joint EPA/EPRI NOx Control Symposium, Denver, CO, 1981.

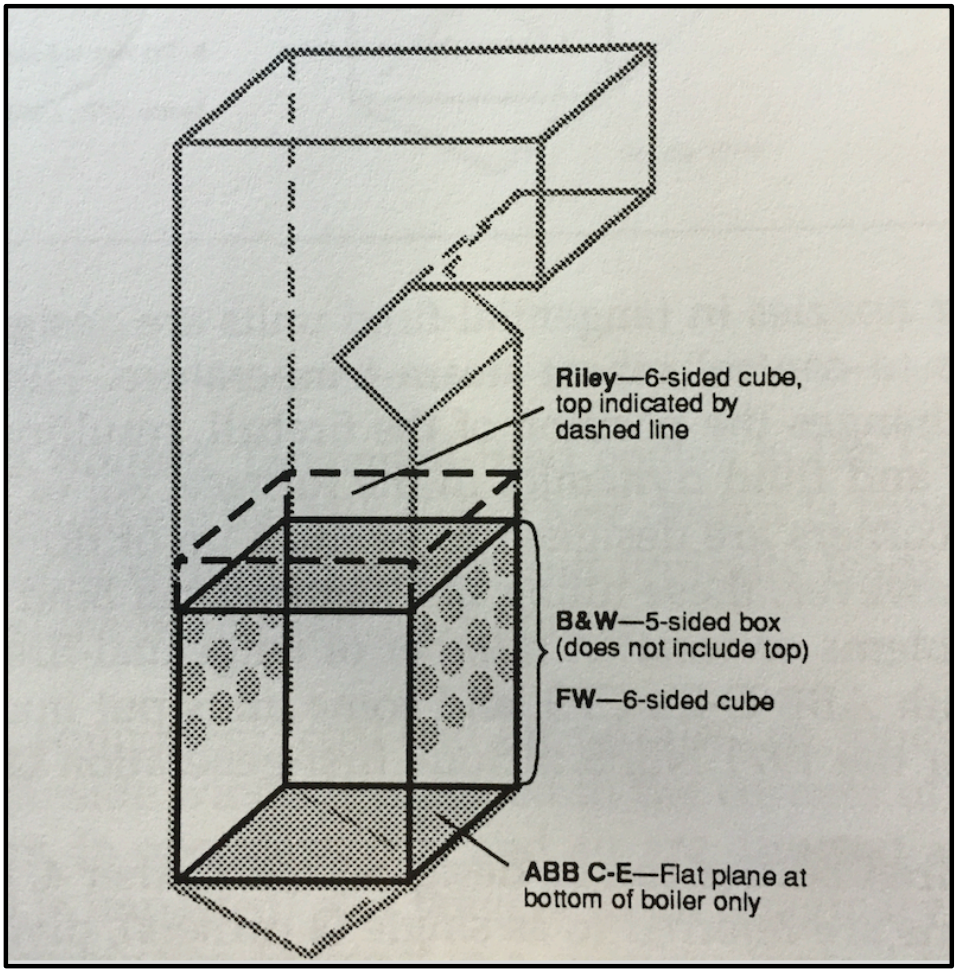

Figure 6. Definition of Burner Zone Liberation Rate: Four Major Boiler Suppliers

In summary, BZLR is key in minimizing NOx emissions. The retrofit of advanced combustion controls may not provide the same NOx control on earlier "legacy" boilers with higher BZLR compared to more recent designs with lower BZLR values. Figure 7 depicts the evolution of advanced boiler technology by one supplier (B&W), showing the progress achieved in recent decades with both subbituminous and bituminous coals. None of these systems achieves the lowest NOx rates, claimed by EPA as being below 0.10 #/MBtu.

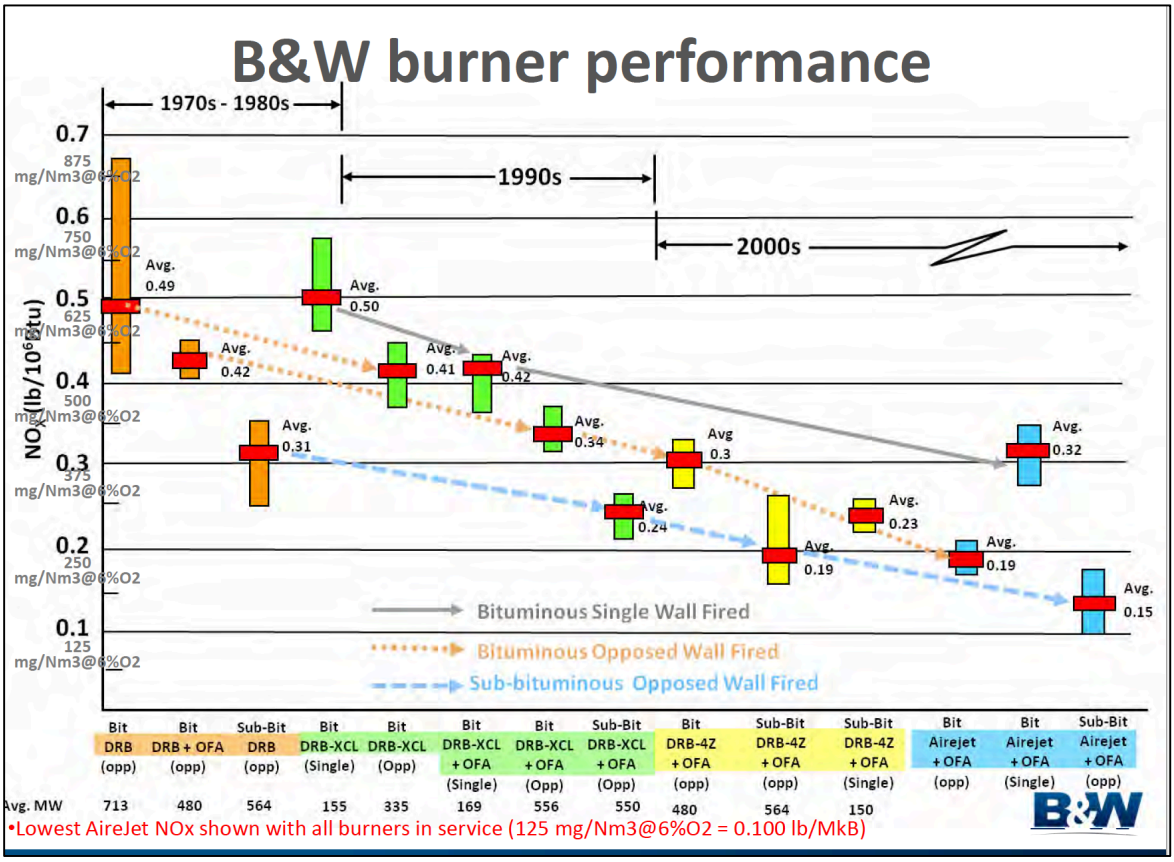

Figure 7. Wall-Fired Boiler Experience with Evolving Low NOx Burner Technology

3.2.3 Owner Experience

The challenge of meeting NOx emission rates as proposed by EPA with bituminous coal was experienced by a Midwest Ozone Group (MOG) member utility. This owner evaluated a tangential-fired boiler firing bituminous coal for an upgrade from LNCFS II to LNCFS III technology. Unit NOx emissions could not approach 0.25 lb/MBtu with a coal prone to slagging (e.g. high Fe content) and corrosion due to high sulfur and chlorine content. A negligible benefit in NOx reduction was derived evolving from LNCFS II to LNCFS III. The owner was advised by a third-party consultant that reduction in boiler exit NOx beyond approximately 0.35 lbs/MBtu would affect the reliability of the unit due to slagging and corrosion on the waterwalls. This experience is consistent with the earliest reports of LNCFS II and LNCFS III control technology on bituminous coal, which report LNCFS II reduces NOx by 40-50% of uncontrolled values, while LNCFS III is capable of up to 50% NOx reduction.[25]

The owner opted to retain the existing LNCFS II burners and employ a neural network control system to lower NOx and minimize the slagging and corrosion issues.

[25] *Alternative Control Techniques Document – NOx emissions from Utility Boilers*, Report EPA-453/R-94—023, March 1994. See page 5-54.

3.3 Combustion Control Cost Basis

Regarding the cost of combustion controls, the EGU TSD notes:[26]

> *Consequently, EPA identifies $1,600/ton as the cost level where upgrades of combustion controls would be widely available and cost-effective.*

Unlike the case for SCR, where EPA submitted a detailed analysis (albeit with the limitations cited in Section 2), there is no analogous cost evaluation for deploying the advanced combustion control technologies in Table 1 of the EGU TSD. Rather, EPA conducted a spreadsheet-based sensitivity study using inputs from the IPM model[27] for a hypothetical 500 MW unit.[28] EPA's analysis does not determine the marginal cost for the incremental NOx reduction, nor does it account for the variability of NOx control due to fuel composition and boiler design, as described in the preceding subsections.

Takeaway: EPA's projection of low NOx emission rates is flawed as it appears to not apply to the majority of the units in the 12-state region that burn bituminous coals. Only newer units which feature relatively low Burner Zone Liberation Rates could likely replicate the claimed low NOx conditions; many existing legacy boilers are unlikely to achieve these rates. EPA's projection of NOx control capability of advanced combustion controls is flawed as it does not consider coal rank, boiler design features, and operating characteristics. Such an analysis is beyond the scope of these comments.

Regarding cost, EPA's evaluation of a hypothetical 500 MW plant – varying only fuel rank and capacity factor - does not capture the range of cost implied for the national inventory. Similar to the analysis for SCR-equipped units, EPA does not consider marginal cost of the incremental reduction in NOx emissions.

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[26] EGU TSD, see page 10.
[27] See Table 5-4 of Chapter 5 of the IPM 5.13 documentation. Available at https://www.epa.gov/sites/production/files/2015-07/documents/chapter_5_emission_control_technologies_0.pdf
[28] EGU TSD, see footnote #19.

4. Critical Maintenance and Retrofit Schedule Issues

Section 4 addresses timelines required for (a) upgrading or otherwise restoring SCR process equipment to achieve 80-90% NOx removal, while controlling residual ammonia, (b) retrofit of SCR process equipment to units that have not deployed the technology, and (c) retrofit of next-generation combustion controls. The timeline for item (a) is presented to describe the limited options available to enhance NOx control from existing SCR equipment. Items (b) and (c) are offered in response to solicitation of Comments C-8 and C-1.

4.1 Existing SCR Process Equipment

There are four maintenance and operation activities for existing SCR process equipment required to achieve high NOx removal. Three of these four activities require extended planning or procurement that, with rare exceptions, will not be able to be implemented within the 6-week period from the March 15 issuance date of the final rule to the May 1 beginning of the 2021 ozone season. These four maintenance and operating actions are (a) tuning of ammonia injection grid hardware, (b) replacement and repair of cleaning hardware such as acoustic horns and sootblowers, (c) cleaning of installed catalyst to remove accumulated fly ash, and (d) replacement or addition of catalyst. Each of these necessary actions is further elaborated as follows:

<u>Tuning of Ammonia Injection Grid</u>. SCR process equipment delivers high NOx removal (i.e. exceeding 80%) while abiding by strict limits on residual ammonia (~2 ppm) only if injected ammonia reagent is well mixed with flue gas NOx. Conventional practice requires the degree of uniformity of ammonia and NOx entering the SCR process reactor be described by a RMS[29] deviation of 5% or less at the inlet of the first catalyst layer to maintain high NOx removal and an ammonia "slip" level of 2 ppm or less;[30] where better uniformity (perhaps 3% RMS deviation) is required as catalysts ages. Frequent tuning of the injection apparatus can be required depending on the specific hardware. The use of injection grids –featuring perhaps hundreds of individual injectors – requires tuning at intervals ranging from one to several years; the use of static mixers reduces but does not eliminate the need for this action.

The tuning of a large coal-fired boiler can require – given instrumentation set-up, installation of sampling lines, calibration of analyzers, and evaluation of data – 4-6 calendar days. This work is most reliably done by specialized test crews with dedicated instrumentation that is relocated between sites. There are at most six providers of this service nationwide. Some large utility owners retain this capability in-house, owning the necessary instrumentation and employing the required trained staff. Given time required for travel between sites, equipment set-up,

[29] Root-mean-square, a common statistical metric of variability.

[30] Rogers, K., *Development and Performance Data for Ammonia Injection and Gas Mixing Processes on SCR Applications,* Proceedings of the Power Plant "Mega" Symposium, Baltimore, MD, August, 2008.

calibration, testing and equipment breakdown, it is unlikely more than 25 units could be so tested in the available 6-week time interval.

Replacement, Repair of Cleaning Devices. The effective operation of cleaning devices – acoustic horns and sootblowers – is necessary to maintain clean catalyst and effective NOx control. These devices are inspected and refurbished as needed; one common acoustic horn failure is the blocking or failing of the diaphragm that generates the acoustic power. Sootblowing mechanical components should be inspected and refurbished as needed. Inspection and repair of acoustic horns requires unit shutdown for internal reactor access.

Each layer of catalyst is typically equipped with an array of either acoustic horns or sootblowers. Given the requirement for shutdown, inspection, and acquiring replacement parts, within a 6-week period it is unlikely that more than 10-15% of units with these cleaning devices can be inspected and refurbished.

Manual Catalyst Cleaning. An important routine action required for most SCR reactors is removal of accumulated ash from the catalyst surface. Despite the use of gas flow modeling and other techniques to design ductwork and reactors to minimize fly ash drop out, and the availability of catalysts with larger pitch or plate spacing, many SCR reactors experience fly ash blockage of up to 30-40% per layer of catalyst.

Manual cleaning and removal of ash deposits from catalyst surface is a labor-intensive process. The steps required for a large reactor include time for process equipment "cool down" to enable access of personnel; layer-by-layer cleaning and ash removal; and examining and repair of seals to minimize bypass of gas to be treated. The process can require 4-6 days. Similar to ammonia injection grid testing, specialized services are required for this work although some owners conduct this work with staff acquired from a labor pool.

Within the 6-week period perhaps 10-15% of units in the 12-state region could deploy cleaning.

Catalyst Replacement. Catalyst that is deactivated – the "activity" for NOx removal is compromised to 65% or less of the initial value - must be replaced with either "new" product or regenerated catalyst. Catalyst replacement frequency varies widely and is prompted by a combination of deactivation or severe blockage by deposits that cannot be manually removed by vacuuming.

Replacing spent or partially deactivated catalyst with new catalyst requires approximately one year for specification of the catalyst design, competitively bidding options and selecting a successful candidate, and the manufacture of catalyst that is installed during the outage. There are 4-5 major catalyst suppliers in the U.S. that provide SCR catalyst; the historical "lead time" for production of "new" catalyst is 9 months to one year.

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, the required catalyst has been purchased and is in storage, or a provider of regeneration services has the required catalyst in inventory.

In summary, within the 6-week period at most 5-10% of units in the 12-state region could replace catalyst, but only if such material was already manufactured and in storage or scheduled for production in early 2021.

Takeaway. There are few options that an owner can utilize within a 6-week window to remedy deficiencies and support increasing NOx removal from moderate levels of 50-70% to 80-90%.

4.2 Retrofit of SCR Process Equipment

EPA solicits opinion regarding the schedule for the retrofit of SCR process equipment to generating units.

> *EPA is requesting comment on this proposal's determination that new post-combustion controls (SCR or SNCR) are not possible to implement on a regional basis by the start of the 2024 ozone season (Comment C-8).*

EPA is interested in determining if 39 months is an adequate period for regional SCR application (as opposed to a few select units).[31]

Utility industry experience with SCR process design and procurement supports a minimum of 39 months for most SCR projects. Figure 8 presents the schedule for installation of 18 projects from the beginning of engineering through process startup.

A few instances exist in which SCR retrofit was implemented in less than 39 months – for example Georgia Power Hammond Unit 4 and one Kyger Creek unit – but these installations are not representative of conventional practice. Georgia Power SCR-equipped units share a design basis with other units owned by the Southern Company; thus, design activities were minimal. Five units at Kyger Creek share an almost identical design, and unit-by-unit construction was continuous, reducing both the design and erection schedule. The SCR process for Associated Electric Co-Operative Thomas Hill Unit 3 – a near-identical design to that employed for Units 1 and 2 - required 36 months.

All other SCR installations required approximately 39 months or more. In summary, although it is possible select units could retrofit SCR in less than 39 months, such examples appear unique. Either process design was established for a near-identical application, and/or the economies of scale for installing SCR on multiple units could be exploited. Some installations required more than 50 months due to site-specific conditions.

[31] For SCR, the total time associated with project development is estimated to be up to 39 months for an individual power plant installing controls on more than one boiler. However, more time is needed when considering installation timing for new SCR controls regionally. EPA has previously determined that a minimum of 48 months (four years) is a reasonable time period to allow to complete all necessary steps of SCR projects at EGUs on a regional scale. 85 Fed. Reg. 68998 (October 30, 2020).

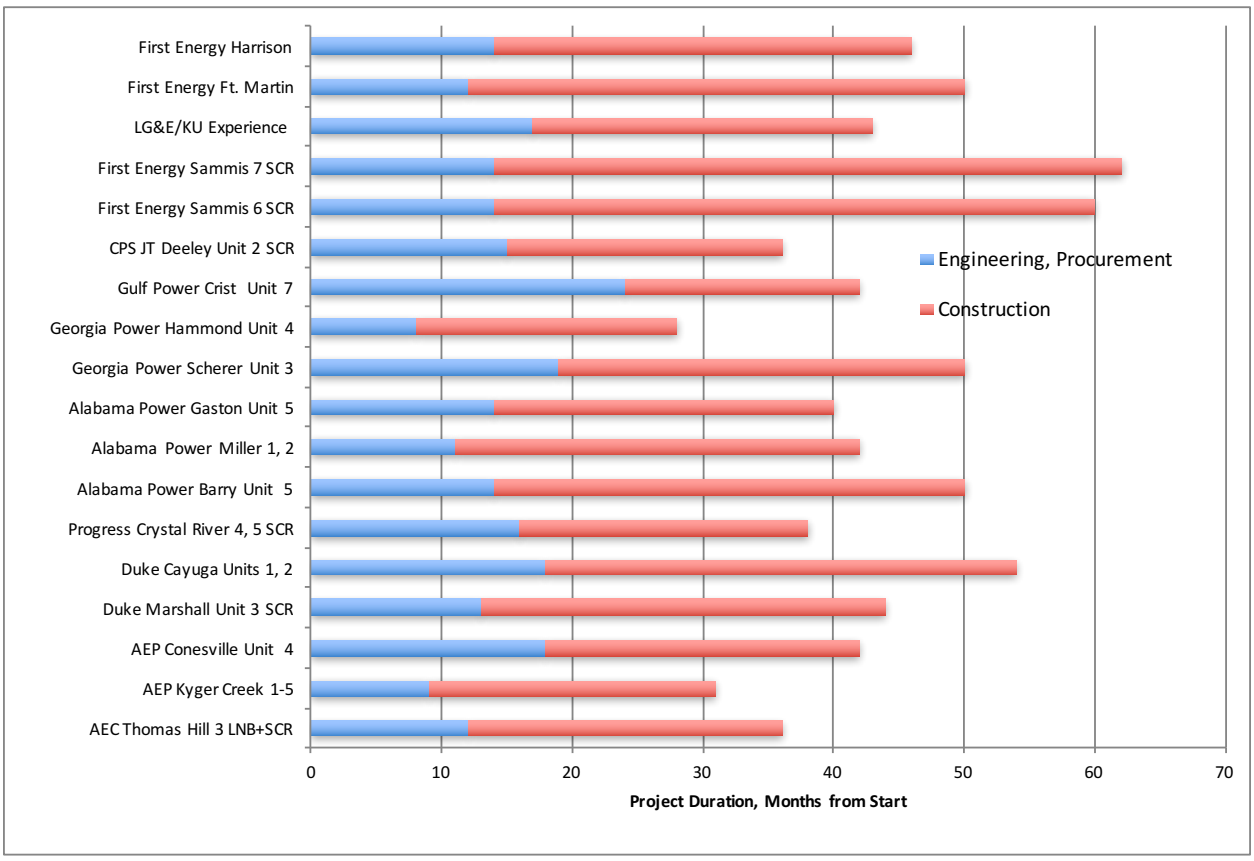

Figure 8. Example Timelines for Engineering and Installation of SCR Process Equipment

The cost for retrofit will readily exceed the reference value of $1,600/ton for both subbituminous and bituminous coals. A detailed treatment of NOx control cost for such retrofits was reported using actual owner-reported capital costs and by the Utility Air Regulatory Group (UARG).[32] Figure 9 presents a revision of the UARG analysis describing annual operation of SCR for present-day market conditions – capital recovery periods of 10 years and 65% capacity factor. These results show the minimum observed capital requirement - $250/kW for a 500 MW unit – would incur a cost of NOx removal for PRB and bituminous coal of $9,742 and $5,000, respectively. For an SCR process capital requirement of $450/kW the NOx reduction cost for PRB and bituminous coal escalates to $16,794 and $8,520 /ton, respectively.

[32] Capital Cost and Cost-Effectiveness of Electric Utility Coal-Fired Power Plant Emissions Control Technologies: 2017 Update, Utility Air Regulatory Group, December 2017. The work showed retrofit of SCR for a cost of $250/kW for a 500 MW unit incur a cost of NOx removal for PRB and bituminous coal of $6,400 and $3,200, respectively. For an SCR process cost of $450/kW these cost for PRB and bituminous coal escalate to $11,000 and $5,800 /ton, respectively.

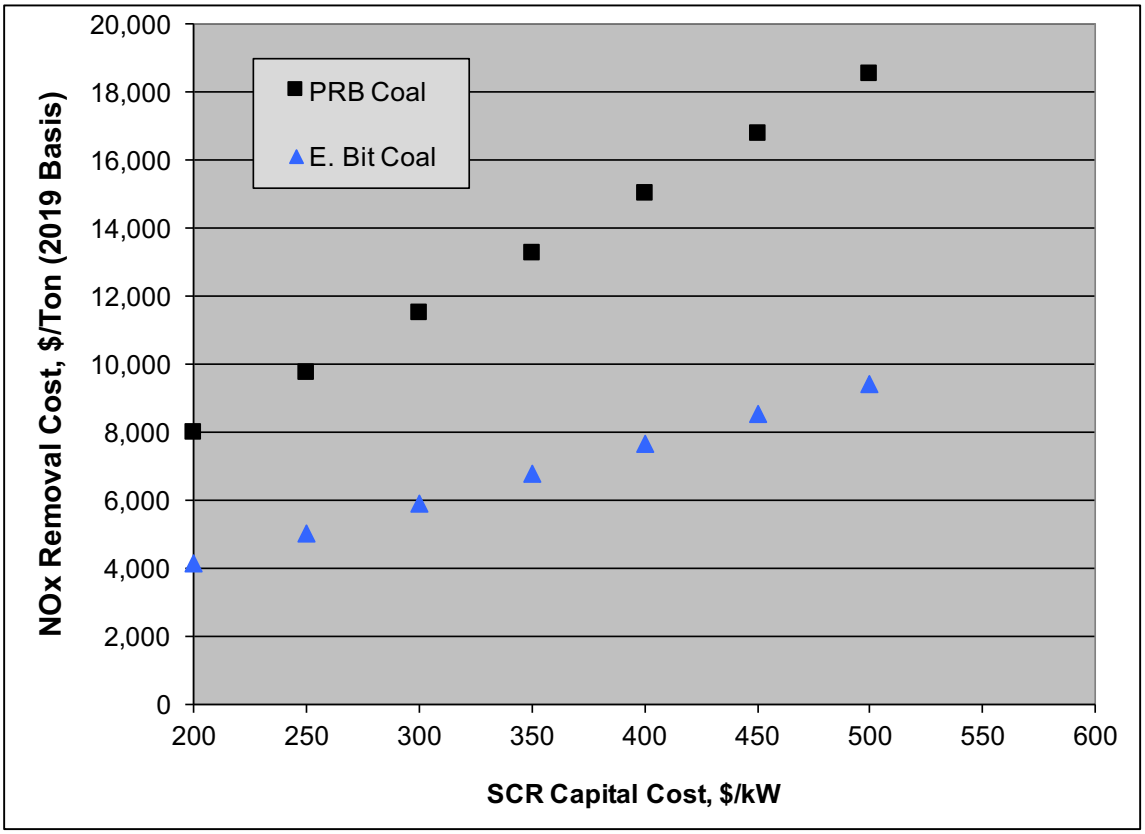

Figure 9. SCR Control Cost (Annual Basis) per Capital (10-yr Life, 65% Capacity Factor)

Further, EPA's analysis for SCR retrofit in which costs are accounted for only over the ozone season shows most estimates exceed $10,000 per ton.[33]

4.3 Retrofit of Combustion Controls

EPA solicits opinion on the schedule for the retrofit of state-of-art combustion controls. Specifically:

> *EPA is taking comment on whether delaying the incorporation of emission reduction potential from the installation of state-of-the-art NOx combustion controls into state emission budgets until 2022 is necessary (Comment C-1).*

Figure 10 shows a delay to the 2022 state emission budgets for the ozone season is necessary due to the time required for design, procurement, and installation of combustion controls for five example units is at least 13 and up to 19 months. This time frame reflects the entire scope of work which includes: the specification, solicitation and selection of a successful supplier, final design and the procurement, installation, and startup of process equipment. The most abbreviated schedules – for Units 4 and 5 at Plant Watson - is 13 months while Hatfield required slightly more time at 14 months. The other examples indicate from 17 to 19 months a time frame that challenges even the ability to meet the 2022 mandated timeline.

[33] See EPA-HQ-OAR-2020-0272-006, Worksheet Ex_SCR_3rd_Best, Column CK.

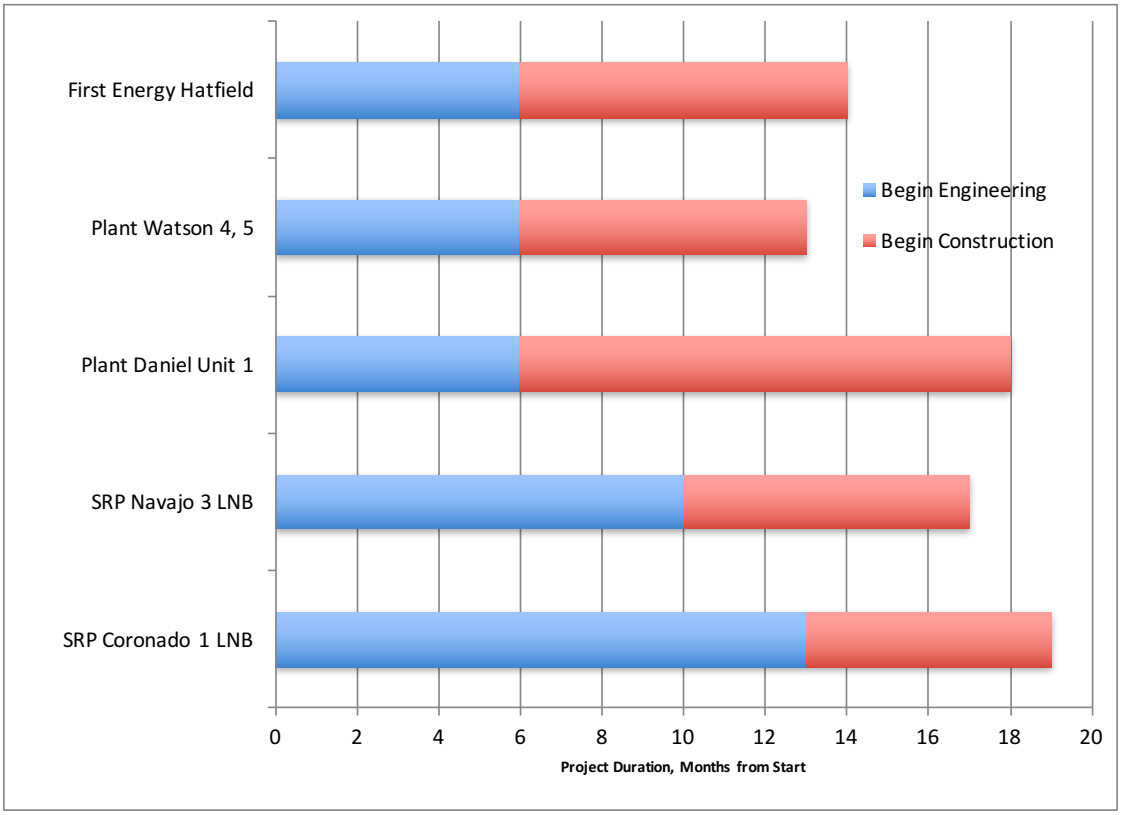

Figure 10. Example Timelines for Engineering and Installation Combustion Controls

In summary, combustion controls could not be deployed in time for the 2021 ozone season; and only a small fraction could be deployed even for the 2022 season.

Takeaway: Of the four categories of SCR O&M activities that are routinely conducted – tuning of the SCR process, repair of cleaning devices, manual cleaning of catalyst, and accelerated replacement of existing catalyst – there is little opportunity to effectively implement these actions in the time frame for 2021 SCR operation. Perhaps 10-20% of the inventory will be able to execute one or more of these actions. This will inhibit many units' ability to meet a 2021 ozone season NOx rate of 0.08 lbs/MBtu,

The time required to install SCR on generating units with a few exceptions exceeds 39 months. Given the final rule will be issued March 15, 2021, it will not be possible to broadly retrofit SCR NOx controls for operating units until the 2024 ozone season which accounts for 38.5 months from the final rule date. The time period for retrofit of advanced combustion controls is at least 13 and up to 19 months. Based on a March 15, 2021 final rule it will not be feasible to retrofit improved combustion control for the 2021 ozone season, with the potential for limited applications in time for the 2022 ozone season.

5. NON-EGU GENERATORS

The EPA requested comments on the capability to deploy combustion controls on non-EGU units.

Specifically, the Agency solicits comments on whether EPA should require that large non-EGU boilers and turbines – as defined in the NOx SIP Call as boilers and turbines with heat inputs greater than 250 MBtu/h or with NOx emissions more than 1 ton per ozone season day - within the 12 states employ controls that achieve emissions reductions greater than or equal to what can be achieved through the installation of low NOx burners.

An aluminum producer operates three field-erected wall-fired boilers with heat inputs ranging from 2201 to 2866 MBtu/h. The units – all initiating commercial duty between 1960 and 1965 – employ Babcock and Wilcox (B&W) boilers and feature a "4 x 4" burner array, designed to fire Illinois bituminous coal. These units were designed prior to broad concern for NOx controls, thus the key design criteria were achieving high fuel use efficiency within a minimum boiler footprint. These objectives were achieved by a compact boiler footprint and high heat release intensity and thus BZLR – as previously discussed in Section 3. The compact arrangement of the boiler limits the space between the burner and the opposing wall, requiring a compact flame length. Consequently, the ability to retrofit combustion controls - which by their very nature (and as discussed in Section 2) require extended flame length – is restricted.

To meet compliance obligations for the NOx SIP Call, the owner had the original burners replaced with B&W low NOx burners and overfire air (DRB-XCL).[34] The EPA CAMD data shows these units operated in 2017 through 2019 at a NOx emission rate ranging from 0.32 to 0.35 lbs/MBtu.

Further NOx control is constrained by the relatively short depth of the combustion chamber. The limited space at present incurs flame impingement with the DRB XCL burners; a more deeply "staged" burner could exacerbate this problem. In addition, the schedule for retrofit of burner technology will resemble that presented in Figure 10.

Takeaway. Large Non-EGU generators are confronted with the same challenges as EGUs – essentially all affected units have to retrofit some form of combustion control technology. For the example aluminum production plant, coal-fired units have adopted a recent version of low NOx burners and given the compact arrangement of the boiler the next-generation low NOx burner it does not appear feasible due to flame impingement. Thus, the present technology can be considered the most advanced feasible, and no further actions available.

[34] Figure 3-2 summarizes NOx control capability with the B&W DRB-XCL, showing that for bituminous coals a NOx emission rate of approximately 0.35 lbs/MBtu is state-of-art achievable.

6. Common Stack Data Analysis and State NOx Budgets

EPA's methodology to evaluate NOx emissions from common stacks (reporting under 40 CFR 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 gas flow configurations results in an underestimation of state budgets for the years of 2021 and 2024. This section describes the shortcomings and proposes revised budgets for the states of Kentucky and Indiana.

EPA determined NOx emissions from SCR-equipped units by improperly parsing reported CEMS data from combined stacks in an attempt to partition emissions between SCR-equipped and non-SCR-equipped units. EPA assigned the NOx tons observed over periods when the unit *not equipped with SCR* was inoperable, assigning these tons to the *SCR-equipped unit* and further assuming these emissions are indicative of SCR NOx control for this unit. EPA has previously apportioned emissions from common stacks for some of these units.[35]

In almost all common stack incidents EPA's approach did not properly reflect the performance of the SCR-equipped unit. As a result, NOx emissions assigned to the SCR-equipped units are excessively high, thus the "balance" of NOx tons assigned to the non-SCR equipped unit are too low. As a consequence, the NOx budget for SCR-equipped units is allocated additional emission reductions for SCR optimization when the units were already operating below 0.08 lb/MBtu. For example, in Kentucky, Cooper Unit 2 has a permit limit from a 2007 consent decree to meet a 0.08 lb/MBtu NOx emission rate on a 30-day rolling average.[36] The unit did not have any NOx emission rate exceedances in the 2019 calendar year. Further, the SCR processes on Shawnee Units 1 and 4 did not initiate operation until the 2018 ozone season, so review of historical data would not report the actual emissions rate from Units 2, 3 and 5 which share the stack.

EPA set SCR emission rates for both Ghent 3 and Clifty Creek 4 and 5 at 0.075 lb/MBtu, but the agency did not apply these rates in either the Indiana or Kentucky budget setting process.[37] Since the budget process is based upon 2019 emission rates, the more correct NOx emission rates that should have been applied to Ghent 3 are 0.046 lb/MBtu and to Clifty Creek 4 and 5 are 0.07 lb/MBtu. There is one exception to the re-assignment of emissions in the Indiana budget setting process discussed earlier and that applies to Rockport. Rockport installed an SCR on Unit 1 in 2017 and installed an SCR on Unit 2 in June 2020, pursuant to a federal consent decree.[38] In addition to requiring the installation of SCR on both units, the consent decree establishes a 30-day rolling average NOx emission rate of 0.090 lbs/MBtu.

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[35] *Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model* (November 2018). See Table 3-18. Hereafter EPA Power Documentation.

[36] www.epa.gov/sites/production/files/documents/eastkentuckypower-cd.pdf

[37] EPA Power Documentation.

[38] www.epa.gov/sites/production/files/2019-07/documents/env_enforcement-2819962-v1-aep_filed_version_of_motion_to_enter_fifth_modification.pdf

Table 2 lists the units and the 2019 SCR NOx emission rates used to adjust both the Kentucky and Indiana state budgets in 2021, based upon discussion with unit operators.

Table 2. 2019 Unit SCR Emission Rates (lb/MBtu)

Unit	2019 SCR Rates (lbs/MBtu)
Ghent 3	0.046
Cooper 2	0.047
Shawnee 1	0.036
Shawnee 4	0.031
Clifty Creek 4 and 5	0.070
Rockport 1 and 2	0.090

Utilizing the revised value of NOx emissions for SCR-equipped units results in a *higher NOx budget* in 2021. Correcting NOx emissions from the SCR –equipped unit to a lower value increases the NOx tons assigned to the non-SCR-equipped unit – the total common stack emissions must remain the same. If the non-SCR-equipped unit is equipped with state-of-the-art combustion controls, then the revised, assigned NOx tons increase will be reflected in the budget for 2022 forward. If the non-SCR unit does not have state-of-the-art controls the 2022 forward emissions will be adjusted based upon retrofitting the unit with a state-of-the-art emission factor.

This critique proposes a remedy to EPA's shortcomings for the state budgets of Kentucky and Indiana. The approach taken was to contact the owners of units emitting through common stacks and obtain unit specific ozone season NOx rates or NOx emissions rate from the SCR-equipped units. These results are used to determine if the SCR was correctly optimized (<0.08 lb/MBtu NOx) in determining the 2021 state budgets. The emissions to the non-SCR-equipped unit were revised (e.g. increased) accordingly. This revision to the common stack data analysis increased the state budgets for both states.

Table 3 presents how these adjustments increased the total budget for Kentucky and Indiana.

Table 3. Adjusted State NOx Budgets per Common Stack Corrections (in tons)

State	NOx Budget: As Proposed				NOx Budget: Revised Per Common Stack Corrections			
	2021	2022	2023	2024	2021	2022	2023	2024
KY	14,384	11,936	11,936	11,936	15,308	12,347	12,347	12,347
IN	12,500	11,998	11,998	9,447	12,902	12,400	12,400	9,849

Takeaway. The states of Kentucky and Indiana feature numerous "common stack" generating stations in which the stack gas from an SCR-equipped unit is blended with that of a unit not equipped with SCR, confounding EPA efforts to ascribe authentic emissions to each individual unit. In almost all cases, EPA incorrectly infers a higher NOx emission rate to the SCR-equipped unit, unavoidably assigning a lower NOx rate to the unit without SCR. As a consequence, this NOx "imbalance" for a SCR unit artificially lowers the NOx budget for a state. Correcting EPA's inferred NOx emission rates for both SCR- and non-SCR-equipped units results in state NOx budget increases.