June 21, 2022

U.S. Environmental Protection Agency
EPA Docket Center
Docket ID No. EPA-HQ-OAR-2021-0668
Mail Code 28221T
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Submitted electronically via https://www.regulations.gov.

RE: THE AMERICAN PUBLIC POWER ASSOCIATION'S COMMENTS ON THE ENVIRONMENTAL PROTECTION AGENCY'S PROPOSED FEDERAL IMPLEMENTATION PLAN ADDRESSING REGIONAL OZONE TRANSPORT FOR THE 2015 OZONE NATIONAL AMBIENT AIR QUALITY STANDARD; 87 Fed. Reg. 20,036 (April 6, 2022); Docket ID No. EPA-HQ-OAR-2021-0668

Administrator Regan:

The American Public Power Association (APPA) is pleased to submit the enclosed comments in response to the Environmental Protection Agency's (EPA or Agency) proposed "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard" (Proposed Rule).[1]

APPA represents community-owned, not-for-profit public power utilities that power homes and businesses in 2,000 communities — from small towns to large cities. Public power utilities safely provide reliable, low-cost electricity to more than 49 million Americans while protecting the environment. These utilities generate or buy electricity from diverse sources. They employ 96,000 people and earn $58 billion in revenue each year. Public power supports local commerce and jobs and invests back into the community.

The power sector is transitioning to lower and non-emitting sources of electric generation, all while providing customers affordable, reliable, and sustainable power. In light of this transition, we respectfully request the agency consider these comments as it works to improve the Proposed Rule. Our comments express concerns with many of the new limitations and constraints placed on the NOx emission trading program and subsequent potential reliability impacts on public power communities. The Proposed Rule would impose burdensome requirements and have a limited impact on addressing nonattainment of the 2015 ozone National Ambient Air Quality Standard. We believe EPA should withdraw its proposal and publish a supplemental notice of

[1] 87 Fed. Reg. 20,036 (April 6, 2022).

proposed rulemaking, eliminating the proposed changes and correcting many of the errors and assumptions underlining the Proposed Rule.

APPA supports comments on the Proposed Rule submitted by its members and the Large Public Power Council and incorporates LPPC's comments by reference.[2]

APPA welcomes the opportunity to work with the agency to improve the Proposed Rule. Should you have questions regarding these comments, please contact Carolyn Slaughter via email (CSlaughter@PublicPower.org) or by telephone at (202) 467-2900.

Sincerely,

Carolyn Slaughter
Environmental Policy Director
American Public Power Association

[2] Comments of the Large Public Power Council on EPA's Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards, EPA-HQ-OAR-2021-0668.

COMMENTS OF THE AMERICAN PUBLIC POWER ASSOCIATION

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FEDERAL IMPLEMENTATION PLAN ADDRESSING REGIONAL OZONE TRANSPORT FOR THE 2015 OZONE NATIONAL AMBIENT AIR QUALITY STANDARD; PROPOSED RULE

87 Fed. Reg. 20,036 (April 6, 2022); Docket ID No. EPA-HQ-OAR-2021-0668

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Submitted by Carolyn Slaughter
Director of Environmental Policy
American Public Power Association
2451 Crystal Drive, Suite 1000
Arlington, VA 22202
202-467-2900

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On April 6, 2022, the U.S. Environmental Protection Agency (EPA or the Agency) published its "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard; Proposed Rule" (the Proposed Rule).[1] The American Public Power Association (APPA or the Association) appreciates the opportunity to submit the following comments on the Proposed Rule. APPA is the voice of not-for-profit, community-owned utilities that power 2,000 towns and cities nationwide. We represent public power before the federal government to protect the interests of the more than 49 million people that public power utilities serve, and the 96,000 people they employ. Our association advocates and advises on electricity policy, technology, trends, training, and operations. Our members strengthen their communities by providing superior service, engaging citizens, and instilling pride in community-owned power. APPA participates on behalf of its members collectively in EPA's rulemakings and other Clean Air Act (CAA or the Act) proceedings that affect the interests of public power utilities. APPA therefore has a clear interest in the present rulemaking. For the reasons discussed below, the Proposed Rule is flawed, unlawful, and should not be promulgated. To the extent EPA moves forward with its proposal we offer the following recommendations to improve implementation:

[1] 87 Fed. Reg. 20,036 (Apr. 6, 2022).

- EPA should undertake full notice-and-comment rulemaking if the agency adjusts state emission budgets from year to year.
- Where state emission budgets are subject to year over year change EPA should conduct an overcontrol analysis in those years.
- EPA should correct its air quality modeling in urban costal areas to account for the unique characteristics of ozone formation in those areas, which is frequently VOC limited. EPA must also conduct a new overcontrol analysis of these costal areas using corrected modeling.
- EPA should increase compliance flexibility in the Groups 2 and 3 trading programs.
- EPA should update its Reference Case analysis, NOx control technology modeling, cost projections and equipment installation timelines which unpin the Proposed Rule. The technical report submitted along with these comments outline the necessary corrections to be addressed in a revised technical analysis that should accompany a supplemental proposal.

II. Introduction

In the Proposed Rule, EPA claims to "adhere[] closely" to the four-step Cross-State Air Pollution Rule (CSAPR) framework that it has used in recent interstate transport rules to address interstate transport for the 2015 ozone national ambient air quality standard (NAAQS), with a few changes to reflect "lessons learned from the performance of regulatory programs established by previous interstate transport rulemakings" and to incorporate "recent information on the nature of ozone transport and emissions reductions opportunities."[2] This is a vast understatement of the magnitude of the Proposed Rule's deviations from EPA's CSAPR framework. EPA's proposed changes to the EGU trading program – including "dynamic budgets" and other proposed "enhancements" – exceed EPA's authority under CAA section 110(a)(2)(D)(i)(I). For the reasons explained below, EPA should modify the proposal to recognize that compliance with the state budgets promulgated by EPA in federal implementation plans (FIPs) implementing the Good Neighbor mandate set out in section 110(a)(2)(D)(i)(I) of the Act eliminate emissions that significantly contribute to nonattainment or interfere with maintenance. EPA should withdraw the Proposed Rule and should publish a supplemental notice of proposed rulemaking eliminating these changes and correcting the many errors and poor assumptions on which the Proposed Rule is based if it plans to issue FIPs.

III. The Proposed Dynamic Budgets and Enhancements Exceed EPA's Authority Under the Good Neighbor Provision and Should Not Be Included in the Final Rule

Section 110(a)(2)(D)(i)(I) of the Act – the "Good Neighbor Provision" – requires states to submit implementation plans (SIPs) that "contain adequate provisions prohibiting … any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will … contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any NAAQS."[3] If a state fails to amend its SIP to prohibit such emissions, EPA is required to propose and promulgate a FIP curing that deficiency.

In *EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489 (2014), the Supreme Court reviewed EPA's interpretation of the Good Neighbor Provision in the original CSAPR and

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[2] 87 Fed. Reg. at 20,041.
[3] 42 U.S.C. § 7410(a)(2)(D)(i)(I).

affirmed "EPA's understanding of which upwind emissions were within the Good Neighbor Provision's ambit."[4] To be within that "ambit," the Court explained, upwind emissions must both (1) contribute "one percent or more of a NAAQS in [a] downwind state," and (2) be able to "be eliminated cost effectively."[5] States were obligated "to eliminate ... *only* emissions meeting both of these criteria."[6] To prohibit emissions meeting both criteria, EPA imposed a "budget" for each state defining the overall cost effective emission reduction target that must be achieved to satisfy that state's Good Neighbor obligations.[7] EPA describes the role of state emission budgets in a consistent manner in the Proposed Rule.[8]

State emission budgets, allocated to sources within each state, create a "cap and trade" system that allows sources that reduce "emissions below the budget target to sell allowances to sources that could not reduce emissions as cheaply."[9] As a result, some units will overcontrol, and others will under control. If control performance of one unit deteriorates over time, the excess emissions from that unit can be offset by reductions at other units in the program. EPA has long touted the compliance flexibility the market-based CSAPR framework allows.[10]

[4] *EME Homer City*, 572 U.S. 502.

[5] *Id.* at 502-03. Using its CSAPR framework, EPA "calculate[s], for each upwind State, the quantity of emissions the State could eliminate at each of several [cost-per-ton] thresholds", *id.* at 501, "then identifie[s] significant cost thresholds, points in its model where a noticeable change occurred in downwind air quality, such as where large upwind emission reductions become available because a certain type of emissions control strategy becomes cost-effective," and ultimately "translate[s] the cost thresholds . . . selected into amounts of emissions upwind States would be required to eliminate." *Id.* at 501-502 (internal quotations omitted).

[6] *Id*. at 503 (emphasis added).

[7] *See e.g.*, 82 Fed. Reg. 23,054, 23,065 (Apr. 30, 2021) (Final Revised CSAPR Update) (explaining the state emission budgets promulgated in that rule "represented emissions remaining in each state after elimination of the amounts of emissions that EPA identified would significantly contribute to nonattainment or interfere with maintenance of the 2008 ozone NAAQS in downwind states").

[8] *See* 87 Fed. Reg. at 20,106 ("an 'emissions budget' is established for each state for each control period, representing EPA's quantification of the emissions that would remain under certain projected conditions").

[9] *EME Homer City*, 572 U.S. at 503.

[10] *See, e.g.*, 76 Fed. Reg. 48,208, 48,210-48,211 (Aug. 8, 2011) (Original CSAPR) ("The Transport Rule's air quality-assured trading approach will assure environmental results in each state while providing market-based flexibility to covered sources through interstate trading"); 87 Fed. Reg. at 20,105 ("The [electric utility] sector's

EPA's Proposed Rule, however, layers "command and control" mandates upon "market-driven" reductions in order to achieve greater, and more costly, reductions than the Good Neighbor provision authorizes. In the Proposed Rule, EPA finds that "as long as the [certain] NOx emissions reduction controls [identified in the Proposed Rule] are available and can be implemented (such as optimization of [selective catalytic reduction (SCRs)]), they must be implemented, even as total NOx emissions reductions on a mass basis decline."[11] EPA's proposals to establish more stringent emission budgets through its dynamic budgeting concept, as well as "command and control" program enhancements implement this finding.

EPA proposes to require "dynamic state emissions budgets" for future control periods beginning with the ozone season in 2025.[12] This will result in reduced budgets, prohibiting previously budgeted emissions, which reflect emissions remaining after application of cost effective emission reductions.[13] EPA also proposes a suite of "enhancements" to the Group 3 trading program, including an annual "recalibration" of the Group 3 allowance bank, to remove what EPA considers to be "surplus … allowances" that "diminish[] the intended stringency [of the program]."[14] EPA characterizes this recalibration as a new "design element," similar to the dynamic emission budgets, that changes the structure of the CSAPR trading program as a whole,

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unusual flexibility with respect to how emissions reductions can be achieved makes the flexibility of a trading program particularly useful as a means of lowering the overall costs of obtaining such reductions").

[11] 87 Fed. Reg. at 20,095.

[12] Under this proposal, state emission budgets would be adjusted for each control period beginning with ozone season 2025 by applying the required control stringency to updated heat input data measured in the year two years before the control period for which the budget would apply (*i.e.*, EPA would use heat input data from 2023 to establish 2025 state emission budgets).

[13] Further, this dynamic budgeting approach could result in regional allowance shortfalls if a relatively high year of generation (i.e., heat input) allowance budget was based on a low year of generation for the prior year used to determine budget allowances. Heat input is variable year over year due to many factors such as extreme weather, outage duration, grid changes and general changes in the dispatch order. Generation owners with larger fleets would have more flexibility to trade compared to owners with a few or only one unit, which is representative of public power utilities.

[14] 87 Fed. Reg. at 20,109.

and is intended "to maintain the rule's selected control stringency and related EGU effective emissions rate performance level as the EGU fleet evolves over time."[15] Additionally, EPA proposes to impose unit-level enhancements intended to "improve emissions performance at individual units."[16] These unit-level enhancements include imposition of a backstop daily NOx emission rate of 0.14 lb/mmBtu on most large coal-fired EGUs,[17] and unit-specific secondary emission limitations that would apply in circumstances where an EGU is deemed to have contributed to an exceedance of a state's assurance level.[18]

By reducing state budgets and imposing program-level and unit-specific "enhancements," the proposal mandates "command and control" reductions in addition to those the affected units have achieved to comply with the "market based" budget program. In other words, they require reductions below budgeted emissions that are not prohibited under the Good Neighbor provision.[19] These budgeted emissions are the emissions that remain after elimination of those emissions that can be eliminated through cost effective emission reductions. As the Supreme

[15] *Id*. at 20,107.

[16] *Id*. at 20,109.

[17] This daily NOx emission rate – which is based on a daily emission rate projected to reflect continuous operation of SCR, *id*. at 20,111 – would apply to coal-fired steam units greater than or equal to 100 MW beginning in 2024 for units with existing SCRs, and to units currently without SCR beginning in 2027. *Id*. at 20,110.

[18] Specifically, unit-specific secondary emission limitations would apply in circumstances where (i) "a state's assurance level for a control period has been exceeded," (ii) "the unit is included in a group of units to which responsibility for the exceedance has been apportioned under the program's assurance provisions," and (iii) "the unit operated during at least 10% of the hours in the control period." *Id*. at 20,112. EPA explains that, "[w]here these conditions … are met, the unit's secondary emissions limitation would consist of a prohibition on NOx emissions during the control period that exceed by more than 50 tons the NOx emissions that would have resulted if the unit had achieved an average emissions rate for the control period equal to the higher of 0.10 lb/mmBtu or 125 percent of the unit's lowest average emissions rate for any previous control period under any CSAPR seasonal NOx trading program during which the unit operated for at least 10 percent of the hours" and "would be in addition to, not in lieu of, the primary emissions limitation applicable to each source." *Id*. EPA also states that "any emissions by a unit exceeding its secondary emissions limitation w[ill] be subject to potential administrative or judicial action and subject to penalties and other forms of relief under the CAA's enforcement authorities." *Id*.

[19] *See, e.g.*, *id*. at 20,039 (noting that the "additional features" EPA proposes to include in the revised Group 3 trading program, including dynamic adjustments to emission budgets and enhancements, are intended to "help maintain control stringency over time and improve emissions performance at individual units, providing further assurance that existing pollution controls will be operated during the ozone season").

Court has emphasized, EPA may only require states to reduce emissions that contribute "one percent or more of a NAAQS in [a] downwind state," and can "be eliminated cost effectively."[20] EPA lacks authority under the Good Neighbor Provision to demand reductions to "improve [an individual unit's] emissions performance"[21] when market driven reductions at other units, or a unit's current emission performance, assures compliance with a state's budget. EPA may only control upwind-state sources to eliminate the "amount[]" of emissions that "contribute significantly to nonattainment in, or interfere with maintenance by," downwind states, quantified in each state's emission budget.[22]

IV. If EPA Had Authority to Change State Emission Budgets, it Could Not Do So Without Conducting Notice-and-Comment Rulemaking.

Even if EPA had authority to adjust states' "Good Neighbor" budgets from year to year, section 307(d) of the Act would require EPA to undertake full notice-and-comment rulemaking in order to do so. CAA § 307(d)(1)(B) (subsection 307(d) "applies to . . . the promulgation or alteration of an implementation plan by the Administrator under section 7410(c) of this title").

In the Proposed Rule, EPA describes a procedure through which it would issue new state emission budgets each year by "ministerial action."[23] As explained previously, state emission budgets are – and have been since the inception of the CSAPR program – the control measure under CAA section 110(a)(2)(A) used to define the amount of emissions that the Good Neighbor

[20] *EME Homer City*, 572 U.S. at 502-503.

[21] 87 Fed. Reg. at 20,109.

[22] 42 U.S.C. § 7410(a)(2)(D)(i)(I). The Good Neighbor Provision does not authorize EPA to impose "enhancements" that go beyond the state budgets. APPA agrees however, that if EPA nonetheless imposes a backstop daily NOx emission rate in a final rule, that rate should not apply to EGUs that commit to retiring by the end of 2028. *See* 87 Fed. Reg, at 20,122. It would not be cost effective for units with planned retirements within this short timeframe to install emission controls or take other similar steps to reduce emissions.

[23] *See* 87 Fed. Reg. at 20,117 (describing EPA's plan to issue a notice of data availability by March 1 of each year beginning in 2024, announcing the state budget for the following ozone season).

provision prohibits. Thus, if EPA had authority to change the stringency of state budgets, it could only do so following a section 307(d) FIP rulemaking.

V. If EPA Had Authority to Require Dynamic Budget Adjustments and other Program "Enhancements," That Authority Could Not be Exercised without Evaluation of Overcontrol in New Rulemakings.

Setting aside whether EPA has the authority to impose dynamic adjustment to emission budgets and other program "enhancements" under the Good Neighbor provision as a general matter, the effect of these program changes is likely to result in overcontrol, which the Supreme Court and the D.C. Circuit have explained is prohibited.[24]

EPA describes its overcontrol analysis in the Proposed Rule, 87 Fed. Reg. at 20,098-99, but does not announce plans to re-evaluate overcontrol in future years, as the budgets are reduced. Instead, EPA asserts without explanation or support that "retention of a constant degree of [control] stringency over time in emissions budgets under a flexible trading program would not constitute overcontrol any more than the permanent imposition of emissions rate standards on individual sources at the time of the rulemaking would constitute overcontrol."[25] This unsupported statement ignores the Supreme Court's instruction to ensure that it does not require emission reductions from a state that exceed "the amount necessary to achieve attainment in every downwind State to which it is linked."[26] Whenever EPA changes the "amount" of emission reductions required of a state, it must also check for overcontrol. Conducting a single overcontrol analysis when a rule is promulgated, as EPA did in past CSAPR rulemakings that imposed static state emission budgets, is not sufficient to prevent overcontrol under

[24] *See EME Homer City v. EPA*, 795 F.3d 118, 126 (D.C. Cir. 2015) (noting "[t]he Supreme Court agreed with the Court of Appeals to this extent: The Transport Rule violates the statute when it requires an upwind State to reduce emissions by more than the amount necessary to achieve attainment in every downwind State to which it is linked" (quoting *EME Homer City*, 572 U.S. at 521) (internal quotations and emphasis omitted).

[25] 87 Fed. Reg. at 20,095.

[26] 572 U.S. at 521.

circumstances where state emission budgets are subject to change from year to year, and daily NOx emission rate limits and unit-level secondary emission limits are in effect indefinitely.

VI. EPA's Decision to Rely on its Standard Modeling to Determine Ozone Linkages and Assess Overcontrol at Receptor Sites Close to Large Water Bodies was Arbitrary and Capricious.

In the preamble to the Proposed Rule, EPA asserts that "the vast majority of the downwind air quality areas are NOx-limited, rather than [volatile organic compound (VOC)]-limited," and "[t]herefore, the proposed rule's strategy for reducing regional-scale transport of ozone targets NOx emissions from stationary sources to achieve the most effective reductions of ozone transport over the geography of the affected downwind areas."[27] This conclusion ignores the results of recent studies of ozone formation in urban areas along large water bodies, including Lake Michigan and Long Island Sound, and the results of EPA's own model performance evaluation.

EPA participated in the 2017 Lake Michigan Ozone Study (LMOS), a collaborative multiagency field study led by the Lake Area Director's Consortium (LADCO) and its member states, together with the National Aeronautics and Space Administration, the National Oceanic and Atmospheric Administration, as well as a number of research groups from universities and other institutions.[28] The results of the LMOS demonstrate that ozone formation occurs differently in urban-influenced coastal areas and is frequently VOC-limited, rather than NOx-

[27] 87 Fed. Reg. at 20,053.

[28] *See, e.g.*, https://www.ladco.org/wp-content/uploads/Research/LMOS2017/LMOS_LADCO_report_revision_apr2019_v8.pdf (Preliminary Finding Report, initial release July 19, 2018, revised release Apr. 22, 2019); https://www-air.larc.nasa.gov/missions/lmos/. As explained in a recent article on the LMOS, "[u]rban-influenced coastal environments are an air quality management challenge because of complex wind patterns, shallow stable marine boundary layers, and the interaction of these meteorological features with ozone precursor (reactive nitrogen and volatile organic compound, VOC) emissions," and as a result, "[m]any of the counties in the eastern [United States] where ozone concentrations exceed the 2015 ozone [NAAQS] of 70 ppb are along coastlines." C. Stanier et al., *Overview of the Lake Michigan Ozone Study 2017*, BULLETIN OF THE AMERICAN METEOROLOGICAL SOCIETY (Nov. 2021) (hereinafter, "C. Stanier").

limited.[29] EPA's Office of Research of Development and EPA Region 1 were also supporters of the Long Island Sound Tropospheric Ozone Study (LISTOS), which evaluated ozone formation and transport along Long Island Sound and observed similar phenomena,[30] and EPA has recently expressed interest in conducting additional research on ozone in areas of coastal Connecticut as a follow-up to LISTOS.[31] This research shows that EPA's standard modeling does not accurately measure ozone concentrations in coastal areas or the contributions from upwind states to ozone concentrations in those areas. In particular, results of the LMOS showed "both the NAM-CMAQ 12-km modeling and the higher resolution (4-km) WRF-Chem modeling" – both of which EPA used in modeling for the Proposed Rule – "underestimate peak ozone concentrations and overestimate NO_2 concentrations during ozone episodes."[32] Differences in ozone formation and transport in coastal areas are due in large part to the influence of sea breeze, or in the case of coastal areas around Lake Michigan, lake breeze.[33] Research on inland penetration of sea breeze has indicated that areas 30 to 40 kilometers (km) inland can be influenced by sea breeze and its

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[29] Technical aspects of the 2017 LMOS are addressed in greater detail in comments being submitted by the Midwest Ozone Group and Ameren Missouri in this rulemaking, and in comments submitted by Ameren Missouri in the rulemaking on EPA's proposed disapproval of Missouri's interstate transport SIP for the 2015 ozone NAAQS. Docket ID No. EPA-R07-OAR-2021-0851-0026. Ameren Missouri's comments on proposed SIP disapproval are incorporated by reference herein. We note that in its Air Quality Modeling Technical Support Document (TSD) for the Proposed Rule, EPA-HQ-OAR-2021-0668-0099 (AQM TSD), EPA states that "The information in this TSD is the same as the information provided in the Air Quality Modeling TSD for the proposed SIP disapprovals, with [the] exception [of] information on additional model runs [in the AQM TSD] that were used to support the ozone transport policy analysis and the [regulatory impact analysis] for th[e] [P]roposed [R]ule." AQM TSD at 1 n.1.

[30] *See* https://www.nescaum.org/documents/listos; *see also* C. Stanier at E2208.

[31] *See* Connecticut 2022 Annual Air Monitoring Network Plan, Connecticut Department of Energy and Environmental Protection, Bureau of Air Management, Draft (May 2022), at 18, *available at* https://portal.ct.gov/-/media/DEEP/air_monitoring/CT2022NetworkPlanDraft.pdf ("EPA has indicated interest in a follow-up study of coastal Connecticut ozone to take place during the summer of 2023").

[32] C. Stanier at E2222.

[33] *See id*. at E2209 ("Lake breeze flows commence in late morning, and are sometimes accompanied by offshore nighttime flows (driven by land radiative cooling) that lead to warmer temperatures over the lake relative to land. Under these conditions, emissions can be trapped when they are drawn out over the lake during night or early morning. This is followed by photochemical ozone production confined in a shallow lake inversion layer. Finally, processed plumes that have undergone substantial oxidation can return onshore with elevated ozone levels during midday and afternoon").

effects, and that a more typical intrusion distance at midday is between 10 and 25 km inland.[34] Specialized modeling techniques and considerations are needed to capture the unique meteorological conditions that lead to ozone formation in these areas, as well as whether and the extent to which upwind-state NOx emissions contribute significantly to nonattainment or maintenance problems in these areas.[35] In VOC-limited areas, NOx emission reductions from upwind states linked to receptors in these coastal areas may not decrease ozone concentrations in the downwind areas, and may result in *increased* ozone concentrations in those areas.[36] EPA is obligated to consider the best available science and to apply that science to its modeling and the conclusions it draws from that modeling, and failing to do so, as it has in the Proposed Rule, is arbitrary and capricious.[37]

EPA's failure to use specialized models to determine ozone concentrations in downwind coastal areas brings into question EPA's linkages and overcontrol analyses for these coastal receptors. EPA acknowledges that its modeling approach did not perform well in areas along

[34] S.T.K. Miller et al., *Sea Breeze: Structure, Forecasting, and Impacts*, REVIEWS OF GEOPHYSICS, AT 1-21. (Sept. 2003) (hereinafter, "S.T.K. Miller").

[35] C. Stanier at E2208.

[36] *See* EPA, "Policy Assessment for the Reconsideration of the Ozone National Ambient Air Quality Standards, External Review Draft" (April 2022), at 2-2 ("[Ozone (O_3)] chemistry is often described in terms of which precursors most directly impact formation rates. A NOx-limited regime indicates that O_3 concentrations will decrease in response to decreases in ambient NOx concentrations and vice-versa. These conditions tend to occur when NOx concentrations are generally low compared to VOC concentrations and during warm, sunny conditions when NOx photochemistry is relatively fast. NOx-limited conditions are more common during daylight hours, in the summertime, in suburban and rural areas, and in portions of the country with high biogenic VOC emissions like the Southeast. In contrast, *NOx-saturated conditions (also referred to as VOC-limited or radical limited) indicate that [ozone (O_3)] will increase as a result of NOx reductions but will decrease as a result of VOC reductions.* NOx-saturated conditions occur at times when and at locations with lower levels of available sunlight, resulting in slower photochemical formation of O_3, and when NOx concentrations are in excess compared to VOC concentrations. NOx-saturated conditions are more common during nighttime hours, in the wintertime, and in densely populated urban areas or industrial plumes") (emphasis added; internal citations omitted). *See also id*. at 3D-19 (Table 3D-1) (identifying the Chicago area as VOC-limited).

[37] *See Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 ("an agency rule would be arbitrary and capricious if the agency has relied on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise").

Lake Michigan.[38] In particular, EPA notes in its Air Quality Monitoring TSD for the Proposed Rule that "[t]he under prediction [of ozone concentrations] at the monitors in the Chicago area as well as Kenosha and Sheboygan may be due in part to an underestimate of the amount of ozone formed in the marine layer over Lake Michigan and the advection of high ozone over the lake onshore as part of the lake breeze circulation near the land-water interface."[39] EPA does not address the results of the 2017 LMOS in the TSD, however, and does not appear to address those results elsewhere in this rulemaking. We also note that, although EPA asserts "the model closely replicates both the day-to-day variability and magnitude of the observed [maximum daily 8-hour average] ozone concentrations on most days" at receptors in coastal Connecticut, *id*. at A-11, data provided in Appendix B to the Air Quality Modeling TSD indicates underprediction of ozone concentrations at the coastal Connecticut monitors relative to 2020 measured concentrations on a scale comparable to the Chicago area monitors. *See id*. at B-3. As noted previously, EPA has recently called for further research of ozone formation and transport in coastal Connecticut.[40] Based on the results of recent studies – which showed that urban coastal areas are not typically NOx-limited, and are frequently VOC-limited – EPA's modeling for the Proposed Rule has likely overestimated the contribution of upwind-state NOx emissions to ozone concentrations in urban coastal areas, and the ability of NOx emission reductions to reduce ozone concentrations in these areas. To properly determine linkages, and evaluate overcontrol in

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[38] *See* AQM TSD, Appendix A, at A-9 (reporting normalized mean bias and mean error were relatively low, with "exceptions … at some monitoring sites mainly in most of Michigan, Wisconsin, the northern portions of Indiana and Illinois, and Upstate New York"); *id*. at A-11 (noting, although "the model closely tracks the day-to-day variability during nearly the entire period … [a]t the Chicago-Alsip and Chicago-Evanston receptors … the model under predicts the observed values for May and June"); *see also id*. (acknowledging that "[a]t the Kenosha-Water Tower monitor the model tends to under predicts [sic] the observed values on most of the measured high ozone days, most notably in May," and "[m]odel predictions are lower than the corresponding observed values on nearly all days at the Sheboygan monitor").

[39] *Id*. at A-11.

[40] Connecticut 2022 Annual Air Monitoring Network Plan, Connecticut Department of Energy and Environmental Protection, Bureau of Air Management, Draft (May 2022), at 18.

urban coastal areas, EPA must model urban coastal areas in a way that takes into account the unique characteristics of ozone formation in those areas.[41] The use of proper modeling would likely result in fewer upwind-state linkages to these receptors and less stringent NOx emission reductions – or no NOx emission reductions at all – to eliminate any upwind-state contribution to nonattainment or maintenance problems in these areas.

The implications of EPA's failure to adjust its modeling approach for coastal monitors for this rulemaking are significant. Receptors located within at least 20 km of the coastline can be expected to be impacted by lake breeze and its effects.[42] All of the projected nonattainment and maintenance receptors located in Illinois and Wisconsin are within 20 km of Lake Michigan, and all of the nonattainment receptors located in Connecticut are within 20 km of Long Island Sound. Most of these receptors are located far less than 20 km inland, with many receptors located directly on the coastline.[43] Modeling at each of these receptors is likely to be affected by the phenomenon observed in the LMOS and LISTOS, and must be adjusted. There are six states that EPA proposes to include in the Group 3 trading program that are linked *only* to receptors in downwind urban coastal areas. *See* AQM TSD at Appendix D (Upwind/Downwind Linkages By Upwind State) (Illinois, linked only to Wisconsin receptors; Minnesota, linked only to Illinois receptors; Missouri, linked only to Illinois and Wisconsin receptors; Pennsylvania, linked only to Connecticut receptors; Texas, linked only to Illinois and Wisconsin receptors; and Wisconsin, linked only to Illinois receptors). In addition, nine other upwind states are linked only to coastal receptors plus the maintenance-only receptor in Philadelphia-Bristol, Pennsylvania, which is no longer modeled to be a maintenance receptor in 2026. *See id*. (Indiana, Kentucky, Maryland,

[41] See *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43.
[42] *See* S.T.K. Miller at 1-21.
[43] *See* https://gispub.epa.gov/airnow/?showgreencontours=false.

Michigan, New Jersey, New York, Ohio, Virginia, and West Virginia). In the Proposed Rule, EPA explains that "all receptors to which Alabama, Delaware, and Tennessee are linked in 2023 are projected to be in attainment in 2026" and for this reason, "no additional emissions reductions are proposed for [sources in these three states] beyond the 2023 level of stringency."[44] To require additional emission reductions from these three upwind states would constitute overcontrol, because any reductions required beyond the 2023 stringency level would require linked states "to reduce [their] output of pollution by more than is necessary to achieve attainment in every downwind State."[45] For the same reason that EPA proposes to determine that no emission reductions can be required from sources in Alabama, Delaware, and Tennessee beyond the 2023 stringency level, depending on the outcome of appropriate modeling of receptors in coastal areas, sources in the states linked only to coastal receptors and to the Pennsylvania receptor may be over-controlled if EPA requires reductions based on continued linkages in 2026, which would require NOx reductions that could be achieved through installation of SCRs at EGUs in these states.

Before it finalizes the rule, EPA must adjust its modeling to take account of the documented differences in ozone formation in urban-influenced coastal areas and should not assume that ozone is NOx-limited in these areas. EPA must also conduct a new overcontrol analysis of these coastal areas using the corrected modeling.

VII. EPA Should Maximize Compliance Flexibility for States Entering the Revised Group 3 Trading Program.

The Proposed Rule represents a significant departure from past interstate transport rulemakings, even for EGUs which have been included in the CSAPR programs from the

[44] 87 Fed. Reg. at 20,098.
[45] 572 U.S. at 521.

beginning. EPA proposes to limit NOx emission reductions from EGUs in 25 states by including each of those state in the CSAPR Group 3 ozone-season NOx trading program. Twelve of these states are included in the existing Group 3 trading program, created through the Revised CSAPR Update, but EPA proposes to impose much lower ozone-season NOx emission budgets for most of them in the revised version of the program; eight states would transition from the CSAPR Group 2 trading program to the revised Group 3 program; and five states would enter the CSAPR ozone-season NOx program for the first time.[46] Based on EPA's projected rulemaking schedule, the final version of the rule may not to be in place by the start of the 2023 ozone season, and if it is in effect by that time, it will likely take effect only weeks before the start of the ozone season.[47] Moreover, EPA requests comment on a number of issues that could affect the outcome of the final rule and indicates that it plans to conduct revised modeling for the final rule. For these reasons, it is possible that the final rule – which will likely be issued only weeks before the start of the 2023 ozone season (or after the start of the 2023 ozone season) will look much different from the Proposed Rule. This creates uncertainty and makes it difficult for EGU owners and operators to plan effectively for compliance with the rule during ozone season 2023 and beyond.[48] Based on this uncertainty, as well as the overall stringency of the Proposed Rule, EPA should maximize compliance flexibility for EGUs in states covered by the final rule. The Proposed Rule includes a number of features that would provide flexibility for EGUs in states entering the revised Group 3 trading program, and APPA supports these aspects of the Proposed

[46] *See* 87 Fed. Reg. at 20,038-39.

[47] *See id*. at 20,113.

[48] As discussed below, the anticipated publication of the final rule just before, or just after, the start of the 2023 ozone season will likely result in states entering the revised Group 3 trading program at different times. This places sources in states that enter the program earlier at a disadvantage, effectively rendering the requirements of compliance with the rule more stringent for these sources, and adding to the need for increased compliance flexibility.

Rule. There are also a number of areas where EPA should revise its proposal to provide increased flexibility.

First, APPA agrees that the five states entering the CSAPR ozone-season NOx trading program for the first time – Delaware, Minnesota, Nevada, Utah, and Wyoming (including Indian country within the borders of those states) – cannot be required to participate in the program until the effective date of the final rule.[49] EGUs in these five states cannot be required to comply with the rule until its effective date and cannot be required to prepare to participate in the program in such a short time.

Second, with respect to the states that are already covered by the existing CSAPR Group 2 and Group 3 trading programs, APPA agrees that it would likely be less disruptive for those states to enter the revised Group 3 trading program at the start of the 2023 ozone season – with provisions in place to prevent the increased stringency of the revised Group 3 trading program from affecting requirements of EGUs in those states before the rule's effective date – than it would be for those states to switch from one trading program to the next during the ozone season. APPA agrees with the prorating procedures for calculating 2023 budgets and variability limits for these states, as well as the five states entering the CSAPR ozone-season NOx program for the first time.[50] However, APPA members anticipate that compliance with the rule will be quite costly, based on Group 3 allowance prices, and these costs present a unique burden for community-owned utilities. Additional flexibility is needed to shield affected units from these high compliance costs during the time period between the start of the 2023 ozone season and the effective date of the rule. This flexibility could be provided through adjustments to the prorating

[49] 87 Fed. Reg. at 20,113.
[50] *Id*. at 20,113.

procedures that would provide an increased number of allowances to be used for compliance by these units at the start of the 2023 ozone season, before the rule's effective date.

Third, APPA agrees that the three states that EPA proposes to determine are no longer linked to downwind problem areas in 2026, and whose budgets therefore will not reflect installation of SCRs in 2026 – Alabama, Delaware, and Tennessee – should be included in the revised Group 3 program instead of comprising a separate trading program or exiting the Group 3 trading program for the 2026 ozone season.[51] While, as explained previously, the "enhancements" that EPA relies on in the Proposed Rule to conclude that it is appropriate for these three states to be included in the revised Group 3 trading program are unlawful, *see id.*, the overall stringency of the state budgets as proposed, and the state assurance levels, will limit the ability of EGUs in these three states to rely on allowance trading for compliance with the rule. More fundamentally, the Good Neighbor Provision still applies after the FIP is promulgated. If emissions from EGUs in the three states that are not linked to downwind nonattainment or maintenance-only areas in 2026 increase their emissions to the point where their states significantly contribute to nonattainment by or interfere with maintenance of the 2015 ozone NAAQS in future years, the Good Neighbor Provision will require additional emission reductions to eliminate those contributions. EPA lacks authority to require additional NOx emission reductions under the Good Neighbor Provisions until that time.

Finally, APPA agrees that EPA should convert Group 2 allowances banked for control periods before 2023 to Group 3 allowances, but EPA should use a less restrictive conversion ratio than proposed. As described previously, EPA should allow for maximum compliance flexibility based on the stringency of the state emission budgets set out in the Proposed Rule, the

[51] *See id.*

expected timing of the publication and effective dates of the final rule, and the introduction of states to the CSAPR ozone-season NOx trading program that have not been included previously. EPA proposes to conduct the conversion of Group 2 allowances based on a target number of Group 3 allowances to be created, equal to the sum of the variability limits in 2024 of the states transitioning from Group 2 to Group 3.[52] This conversion would occur after the proposed recall of Group 2 allowances equivalent in quantity and usability to all 2023 and 2024 vintage year Group 2 allowances previously allocated to sources in states transitioning to Group 3.[53] The proposed conversion factor is overly restrictive and substantially more restrictive than the conversion factor implemented in the CSAPR Update, which EPA states it is using as a model.[54] EPA estimates, based on the current quantity of banked Group 2 allowances, that the conversion ratio proposed would be approximately 5.9-to-1.[55] This is overly restrictive and has the effect of penalizing sources that met their CSAPR Group 2 emission budgets through emission reductions and built a bank of allowances through early emission-reduction action, which is the very compliance behavior EPA seeks to encourage in the Proposed Rule. Banked allowances represent assets that EGU owners – in the case of public power, communities – have invested in over the past several years to allow for compliance flexibility when needed, and to offset costs as needed through the sale of allowances. Seizing these assets through conversion is likely to

[52] *See id*. at 20,135.
[53] *Id*. at 20,137.
[54] *See* 81 Fed. Reg. at 74,577 (Final CSAPR Update, applying a "conversion factor … determined based on the ratio of the total number of banked Group 1 allowances being converted to 1.5 times the sum of the variability limits for all states covered by the Group 2 program").
[55] 87 Fed. Reg. at 20,136.

discourage early emission reductions in the future and risks disruption of the environmental markets.[56]

If EPA promulgates state budgets at levels in line with the stringency of the proposed budgets, EPA should allow for unrestricted use of banked Group 2 allowances for compliance with the revised Group 3 program. In the alternative, EPA should at least use a much less restrictive conversion ratio. This would ease the transition to more stringent Group 3 program for states currently in Group 2 and Group 3 programs, and for states entering the ozone-season NOx program. It would also help to avoid or minimize the electric reliability issues that are likely to occur as a result of the proposed budgets (addressed below). The state assurance limits will establish an effective upper limit on the number of banked and purchased allowances that can be used in any compliance period. As noted previously, states also remain bound by the Good Neighbor Provision to ensure that emissions from sources within their borders do not emit in amounts that will contribute significantly to nonattainment by or interfere with maintenance of the 2015 NAAQS in downwind states in future years.

VIII. Key EPA Judgments and Policy Decisions Underlying the Proposed Rule are Inappropriate and Unjustified.

As described in a technical critique of the Proposed Rule prepared for APPA and other industry stakeholders attached as Appendix I, the Proposed Rule is based on the cost and performance capabilities of NOx control strategies, and many of the EPA's judgments and policy

[56] *See* Matthew Polesetsky, *Will a Market in Air Pollution Clean the Nation's Dirtiest Air?: A Study of the South Coast Air Quality Management District's Regional Clean Air Incentives Market*, 22 ECOLOGY L. Q. 359, 374-75 (1995) ("[P]ollution credit markets operate on the assumption that polluters will develop rational responses to the incentives that the market creates. Sources that find it extremely costly to reduce their emissions have an interest in negotiating with sources that can reduce emissions relatively inexpensively. This process of pollution credit transfer requires planning. Planning, in turn, requires the ability to predict the future with some degree of certainty. If market participants believe that regulators will whimsically change the rules of the market, firms lose the ability to plan for the future. In the worst case scenario, market participants may fear that regulators will confiscate the credits that the participants generate.").

decisions relating to these strategies are flawed and incorrect.[57] The result of EPA's inappropriate and unjustified judgments and decisions is a proposal that would establish state NOx emission budgets and other requirements that are unattainable at the cost-per-ton thresholds or within the timeframes that EPA assumes they will be, and some that may not be attainable at all without sacrificing system reliability. EPA must revise the inaccurate judgments and assumptions underlying its modeling for the Proposed Rule and conduct new modeling that corrects the flaws and errors identified in the Technical Report before promulgating any final rule. EPA must also make the details and results of any such new modeling available for public review and comment.

While the assumptions and analysis used to support the Proposed Rule are problematic, APPA does support EPA decision to continue excluding stationary, fossil fuel-fired boilers serving a generator with nameplate capacity of 25 MWe or less producing electricity for sale from the proposal. Retrofitting NOx controls are still neither cost effective nor technically feasible for existing intermittently operated small boilers. Regulating small boilers under this proposed rulemaking could disproportionately increase the burden on small entities with minimal environmental benefit. This outcome would run counter to EPA's decision to "significantly reduce[] the burden on small entities by reducing the number of affected small entity-owned units" under the Regulatory Flexibility Act obligations to minimize disproportionate small entity impacts.[58]

[57] *See* J. Edward Cichanowicz, James Marchetti, Michael C. Hein, and Shirley Rivera, Technical Comments on Control Technology Options and Emission Allocations Proposed by the Environmental Protection Agency in Support of the Proposed 2015 Ozone NAAQS Transport Rule at 3 (June 17, 2022) (Technical Report).

[58] 87 Fed. Reg. 20,166.

A. EPA's Assumptions Regarding the Levels of NOx Emission Reductions that Can Be Achieved Through Control Technology, and the Costs of Those Projected Emission Reductions, are Flawed.

EPA's assumptions regarding the NOx emission reductions that can be achieved through the use of control technology – including state-of-the-art combustion controls and post-combustion NOx controls – are unrealistic. EPA's judgments regarding the cost of installing that control technology and optimizing the operation of controls that are already installed, are also incorrect.

1. Combustion Control Technology

In its modeling for the Proposed Rule, EPA overestimated the ability of combustion control technologies to achieve very low NOx emission rates. *See* Technical Report at 8 (citing statement in EGU NOx Mitigation Strategies Proposed Rule TSD that "[m]odern combustion control technologies routinely achieve rates of 0.20 – 0.25 lb NOx/MMBtu" and can sometimes achieve rates below 0.16 lb NOx/MMBtu, based on the type of unit and the fuel combusted). As explained the Technical Report, these assumptions are derived from projected NOx emission rates based on ideal circumstances for NOx emission reductions, including combinations of fuel composition and unit design that are not typical and should not be extrapolated to the national inventory.[59] EPA also ignored the role of boiler design features in achieving lower NOx emission rates, and failed to consider that retrofit of advanced combustion controls will not result in the same NOx emission rate reductions from older vintage boilers as it will with newer boiler designs.[60] The Technical Report provides more realistic NOx emission rates that may be achieved on average, based on specified combinations of fuel types and firing equipment, most

[59] Technical Report at 8 and 11.
[60] *Id*. at 11.

of which result in higher NOx emission rates than EPA assumed.[61] It also explains that, based on EPA's flawed assumptions regarding the availability of NOx emission reductions through the use of combustion control technology, the cost per ton of NOx emission reductions that EPA projects is much higher than estimated in the Proposed Rule.[62]

2. Post-Combustion Control Technology

In the Proposed Rule, EPA assumed that NOx emission reductions will be achieved through optimizing the use of SCR and selective noncatalytic reduction (SNCR) equipment already in place by the 2023 ozone season, and through installation of new SCR and SNCR equipment by the 2026 ozone season. Several of EPA's assumptions relating to the availability and capability of this equipment and the cost of any reductions derived from the use of this equipment are flawed. These flawed assumptions result in unrealistic projections and artificially low NOx emission budgets.

a. SCR

EPA's estimates of the NOx emission reduction performance that can be achieved through optimization of existing SCRs are flawed. In particular, the assumption that maximum NOx removal potential for an SCR is equivalent to the NOx emission rate achieved during the third lowest ozone season since 2012 ignores that NOx control performance degrades over time with the state of the catalyst and the ability to maintain a uniform mixture of ammonia reagent to NOx generated in the boiler.[63] It is unrealistic to assume that existing units can achieve the same NOx rates that they achieved historically on a year-to-year basis, particularly without significant capital expenditures and increased operations and maintenance costs.[64] Additionally, the

[61] *See id*. at Table 4-1.
[62] *Id*. at 14.
[63] Technical Report at 18.
[64] *Id*.

methodology that EPA used to estimate the capital cost of installing SCR at units throughout the 25 states covered by the Proposed Rule is outdated and unrealistic.[65]

b. SNCR

The number of units that EPA assumes in the Proposed Rule will be retrofit with SNCR is more limited than SCR, but EPA's assumptions of the NOx emission reduction performance for SNCRs are also unrealistic. EPA asserts that SNCR control capability ranges from 20 to 40 percent, depending on the application.[66] This estimate misjudges the complex procedure of introducing ammonia reagent during a narrow temperature window to optimize NOx reduction, and the variability in NOx emission reduction that can occur during this process.[67] In reality, the upper limit of SNCR control capability for most units is 30 percent.[68] As with SCR, the methodology that EPA used to estimate the capital cost of installing SNCR is unrealistic and fails to capture the variability in operating costs.[69]

B. EPA Underestimates the Time Required to Install NOx Control Technology

EPA's assumptions regarding the time needed to install NOx emission control technology on the regional scale it assumes in the Proposed Rule are unrealistic. As a result, NOx emission reductions from the use of new or optimized control equipment will not be available within the timeframes reflected in the budgets for the Proposed Rule.

1. Combustion Control Technology

EPA's projection that state-of-the-art combustion control upgrades can be achieved by the start of the 2023 ozone season (*i.e.*, just over a year from publication of the Proposed Rule) is

[65] *Id*.
[66] Technical Report at 22.
[67] *Id at 22-23.*
[68] *Id*.
[69] *Id*.

based on outdated information derived from a limited number of atypical retrofits.[70] In reality, it will take 22 months on average to retrofit these combustion controls.[71] EPA therefore should not assume that emission reductions can be achieved through installation of state-of-the-art combustion controls before the 2024 ozone season, and should not assume that all installations could be achieved by that time.[72] APPA member Kansas City Board of Public Utilities (BPU) has assessed that it would take 24-30 months (December 2, 2009) to install combustion controls like low NOx burners and overfired air and 40-60 months to install back-end emission controls (October 9, 2011). This timeframe includes selling municipal bonds, conducting a rulemaking proceeding, and procuring engineering and completing construction associated with installing new equipment.

2. **Post-Combustion Control Technology**

EPA assumes that SCR and SNCR equipment can be installed at EGUs throughout the 25 states covered by the Proposed Rule in time to achieve NOx emission reductions by the start of the 2026 ozone season (*i.e.*, approximately 48 months from publication of the Proposed Rule). The typical installation timeframe for a single SCR is 40 months, and the timeframe for retrofit of multiple SCRs at a single site is 45 months.[73] However, the time that would be needed to install SCR on the scale called for in the Proposed Rule is much longer.[74] This is largely due to the inadequacy of resources – including equipment and labor – needed to install SCR at the number of units and within the geographic area assumed in the Proposed Rule.[75] Installation of SCR on the scale assumed in the Proposed Rule would need to be staged over several years, and

[70] *Id*. at 16-17.
[71] *Id*.
[72] *Id*.
[73] *Id*. at 24-25.
[74] *Id*.
[75] *Id*.

could not be achieved by the start of the 2026 ozone season even if engineering and procurement began when the proposed Rule was published.[76] We also note that EPA's erroneous timeline assumptions do not take into account recent and ongoing supply chain disruptions, or the high demand for major power plant equipment, material, and construction. EPA also appears to assume, without explanation, that there will be sufficient workers and construction housing available across the regulated states to complete these SCR retrofit projects by the start of the 2026 ozone season. A lack of available construction workers and housing is of particular concern for public power utilities with affected EGUs in rural areas and could delay project completion beyond the 2026 ozone season. In the final rule, EPA should allow for an extension to install SCRs based on a showing of necessity, similar to EPA's proposal to offer non-EGUs a compliance extension to install SCRs.[77] This is particularly important for public power.

C. EPA Vastly Underestimated the Cost Per Ton of NOx Emission Reductions in the Proposed Rule.

As the Technical Report explains, EPA underestimated the cost per ton of the NOx emission reductions to be achieved through control technology by orders of magnitude. This is due in part to EPA's decision to assign a 10-year life for recovery of SCR capital costs, which has the effect of lowering the incurred cost-per-ton of NOx removed through the use of that technology.[78] In reality, some units will cease operations before reaching the assumed 10-year life.[79] A 5-year life for recovery of capital costs is more realistic and may double the incurred

[76] *Id*.

[77] *See* 87 Fed. Reg. at 20,104 ("EPA . . .requests comment on whether the FIP should provide a limited amount of time beyond the 2026 ozone season for individual non-EGU sources to meet the emissions limitations and associated compliance requirements, based on a facility-specific demonstration of necessity.").

[78] Technical Report at 1.

[79] *Id*.

cost-per-ton.[80] EPA underestimates the incurred cost per ton using a 10-year life for recovery, and the overestimation is compounded when a 5-year life for recovery is considered.

Specifically, as explained in the Technical Report:

- The retrofit of SCR to coal units incurs a cost for the median unit in the population that ranges from \$20,250 per ton for operation at the 56% capacity factor, escalating to approximately \$28,000 per ton for units at the 90% population.
- The retrofit of SCR to distillate oil/gas-fired units – which would apply to 35 units under the Proposed Rule – incurs a cost for the median unit that ranges from \$11,000 per ton for operation at the 56% capacity factor and a 10-year remaining lifetime, to over \$66,000 per ton for operation at the 2021 capacity factor and 5-year remaining lifetime.
- SNCR retrofit as EPA proposes – to coal-fired units of 100 MW generating capacity or less – captures only six units. The incurred cost for the median unit ranges from \$12,645 per ton to more than \$100,000 per ton, which reflects operation at the 2021 capacity factor and 5-year remaining lifetime.

SCR retrofit costs exceed EPA's estimate incurred by the median unit of SCR retrofit of \$15,500/ton for coal at the 56% capacity factor and for SNCR for the population of boilers less than 100 MW of \$10,800/ton for coal application.[81] As a result, EPA's judgments in the Proposed Rule regarding emission reductions that can be achieved cost effectively are incorrect.

[80] *Id*.
[81] Technical Report at 34.

D. Even if Establishment of a Backstop Daily NOx Emission Rate 0.14 lbs/mmBtu were Lawful, Compliance with a Daily Emission Rate Limit at that Level Would Not be Feasible for Most EGUs.

As described previously, EPA lacks authority under the Good Neighbor Provision to establish a backstop daily emission limit at any level for the purpose of requiring EGUs to "improve emissions performance at individual units."[82] Even if EPA were authorized to establish a daily emission rate, however, the rate it proposes to establish would be too low for most EGUs to achieve on a consistent basis, primarily because of unavoidable startup operations. As the Technical Report explains, an examination of 110 well-performing units in the SCR-equipped inventory – each of which recorded NOx emissions of less than 0.08 lbs/mmBtu during ozone season 2021 – demonstrated that approximately 2/3 of these units experienced excursions in the NOx daily rate in excess of 0.14 lbs/mmBtu.[83] Some of these units experienced as many as 13 operating days emitting above this rate during ozone season 2021.[84] This illustrates that a backstop daily NOx emission rate of 0.14 lbs/mmBtu will result in exceedances for even well-controlled and well-performing units, primarily due to unavoidable startup operations.[85] Regardless of whether EPA has authority under the Good Neighbor Provision to finalize a daily emission rate, if it does so, the daily emission rate should be based on a rolling operating average with a longer averaging period than 24 hours such as 30- operating days. A daily rate calculated from 12:00 am to 11:59 pm could result in an exceedance just by virtue of when the unit began start-up. EPA should also provide an exclusion from any daily emission rate for periods of startup, shutdown, and maintenance.

[82] 87 Fed. Reg. at 20,109.
[83] Technical Report at 38.
[84] *Id*.
[85] *Id*.

E. The Generation Shifting Component of EPA's Budget-Setting Methodology Does Not Reflect Real-World Conditions and Should be Eliminated.

Generation shifting is a key element used to mitigate NOx emissions in the Proposed Rule. EPA's Integrated Planning Model (IPM) uses a least-cost approach to electricity generation and transport that allows for generation shifting among EGUs within the transport region that are covered by the Proposed Rule, as well as units that do not meet the applicability criteria for inclusion in the Proposed Rule.[86] EPA's assumptions regarding generation shifting are unrealistic, as IPM assumes there are no barriers to the movement of power within a state or within a regional transmission organization (RTO), disregarding the fact that the design and operation of the power delivery grid frequently dictates movement of energy, making the modeled generation shifts impossible.[87]

Generation shifting has a substantial effect on some state NOx emission budgets, resulting in budget reductions in the range of 700 to 1,100 tons of NOx. *See id*. at sec. 8 (reductions of 1,138 tons of NOx for Kentucky; 971 tons of NOx for Missouri; 717 tons of NOx for Ohio; 1,034 tons of NOx for Texas; and 1,123 tons of NOx for West Virginia). EPA's estimate of the low cost to deploy this approach result in an increased generation of select fossil fuel fired units and intermittent idling of select units across entire states and RTOs. These conditions are unrealistic and should be eliminated from EPA's modeling for the Proposed Rule. They are particularly unrealistic for utilities with units covering more than one RTO. Generation shifting is particularly infeasible for public power. The modeled NOx emission reductions from EPA's poor assumptions relating to generation shifting yield reductions of state emission budgets that will not occur as projected, giving rise to electric reliability concerns.

[86] *Id*. at 44.
[87] *Id*. at 2 and 46.

F. An Analysis of EPA Assumptions and the Resulting State Budgets and Allowance Allocations for Nine States Demonstrates Profound Errors in EPA's Modeling and Assumptions.

The Technical Report describes an evaluation of nine states representing different geographic regions of the 25 states included in the EGU portion of the Proposed Rule, as well as different RTOs and utility structures. An examination of these nine states – Arkansas, Indiana, Kentucky, Missouri, Ohio, Pennsylvania, Texas, West Virginia and Wyoming – reveals serious errors in EPA's modeling and assumptions that must be corrected. First, EPA did not accurately assign NOx emission rates to SCR and non-SCR units sharing a common stack.[88] Second, EPA's modeling included inaccurate assumptions regarding natural gas conversions at EGUs in the nine states.[89] Third, EPA made incorrect assumptions regarding unit retirements in several states.[90] Fourth, EPA included incorrect technology inventory data for units in several states.[91] These incorrect assumptions impacted the NOx emission budgets for these nine states, and indicate flaws in EPA's unit-level assumptions. EPA must examine the assumptions underlying the emission budgets for all states and correct them as needed.

EPA must also make corrections to the state budgets to reflect generally applicable assumptions that are inaccurate and unsupported. As discussed previously, EPA's assumptions regarding the timing for installation of state-of-the-art combustion controls and SCRs should be revised to reflect that retrofit of these technologies is not achievable until 2024 and 2027, respectively. Additionally, EPA must adjust the modeled emission rate for combustion controls

[88] *See* Technical Report at table 9-1 (providing corrected 2021 NOx emission rates for units in Indiana and Kentucky).

[89] *See id*. at Table 9-2 (providing corrections relating to natural gas conversions in several states).

[90] *See id*. at Table 9-3 (providing corrections to EPA assumptions regarding unit retirements in several states).

[91] *See id*. at Table 9-4 (providing corrections).

to reflect variability based on fuel and boiler type.[92] The Technical Report presents a recalculation of the NOx emission budgets for the nine states examined in Table 9-6. Before issuing a final rule, EPA must recalculate the budgets for all 25 states to correct any errors in the baseline modeling for poor unit-level assumptions and eliminate poor assumptions relating to timing for installation of controls.[93] EPA must also make this modeling and the resulting adjustments available for public comment. Given the extent of errors in EPA's assumptions underlying the Proposed Rule, EPA should withdraw the Proposed Rule, conduct corrected modeling that resolves the incorrect assumptions in its modeling for the Proposed Rule and eliminates the other errors identified herein, and should publish a supplemental notice of proposed rulemaking, allowing for public comment of the corrected modeling.

EPA's incorrect assumptions have profound effects on the state emission budgets in the Proposed Rule, leading to system reliability concerns. Within the nine states examined, IPM projected retirement of 32 coal units, representing 9.7 GW of capacity, that have not announced plans to retire within that timeframe, including nine units totaling 6.6 GW that are equipped with SCR.[94] IPM also projected that 42 coal units, representing 14.9 GW of capacity, would be idled in 2023, seventeen of which (totaling 8.5 GW of capacity) are equipped with SCR.[95] In total, IPM incorrectly projected that over 28 percent of operable coal capacity will be idled during the 2023 ozone season.[96] These errors are compounded by incorrect assumptions regarding the feasibility of generation shifting.[97]

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[92] *See id*. at Table 9-5 (providing corrected NOx emission rates by fuel and boiler type).
[93] *Id*. at sec. 9.1
[94] Technical Report at 45.
[95] *Id*.
[96] *Id*. at Table 8-1.
[97] *Id*.

IX. Promulgation of a Final Rule that Imposes State Budgets At or Near the Levels Presented in the Proposed Rule May Result in Electric Reliability Impacts.

APPA members have serious concerns about their ability to meet their customers' demands for electric power and also maintain system reliability beginning in ozone season 2023, if the rule is promulgated with emission budgets consistent with those set out in the Proposed Rule. The Technical Report estimates that there will be an allowance shortfall of 6,310 allowances within the nine states examined during the 2023 ozone season.[98] Any allowances that are available on the market are expected to be available only at very high prices due to market conditions resulting from tightness in state budgets where there are expected to be small allowance surpluses, and the constrains on trading that EPA proposes to implement.[99] These conditions are not expected to improve after 2023. Substantial allowance shortfalls are expected in Kentucky and Texas are expected in 2026, totaling 4,119 tons and 8,780 allowances respectively, even as ozone season emissions decline.[100] The effective allowance emission rates for EGUs in these two states, coupled with allowance shortfalls, will constrain unit operations in these two states and may result in electric reliability issues.[101] These issues will be exacerbated by the need to retrofit 79 units, totaling 42 GW of coal-fired capacity in the 25 states covered by the Proposed Rule with SCR by the start of the 2026 ozone season, including 25 units in Kentucky and Texas alone, representing a total of 11.8 GW of capacity.[102]

Concerns about the ability to maintain electric reliability are especially acute for the public power sector of the electric generation industry, which operates with limited capacity and within narrow margins to provide power to towns and cities nationwide. The recent 2022

[98] *Id*. at Table 9-8.
[99] Technical Report at 62.
[100] *Id* at Table 9-9.
[101] *Id*.
[102] *Id*.

Summer Reliability Assessment report by the North American Electric Reliability Corporation (NERC) further highlights APPA's system reliability concerns.[103] While scope of the report focuses on the upcoming summer, the report's key findings are consistent with findings from NERC's 2021 Long-Term Reliability Assessment and other reports and bear re-enforcing. The report notes that the Midcontinent ISO (MISO) north and central areas will face capacity shortfalls resulting in energy emergencies during the summer peak. Compared to summer 2021, MISO will have 2.3 percent less generation capacity causing system operators to employ mitigation strategies to maintain system reliability. In the Southwest Power Pool there is the potential for insufficient operating reserves according to the report's seasonal risk assessment.[104] In the Electric Reliability Council of Texas (ERCOT) region, transmission expansion projects to add intermittent resources are being monitored for delays or cancellations, which could contribute to local reliability concerns.[105] A preliminary analysis of the potential effect of the Proposed Rule on ERCOT in 2026 identified four areas of concern to maintain reliability: 1) the steady state transmission analysis found an investment of \$1.2 to \$1.5 billion is needed to maintain local reliability of the transmission system, and an additional \$2.7 to \$5.2 billion of transmission improvements would be needed to improve the ERCOT regional transfer capability after the retirement of the Proposed Rule's affected generation; 2) the probability of load sheading during the summer of 2026 increases almost nine times by 8 pm if 10,800 MW of affected generation retires; 3) ERCOT will only be able to approve one third of the expected maintenance outages required by the remaining thermal units in 2026, which will likely result in an increase in forced outages of these remaining units, substantially increasing the likelihood of

[103] NERC 2022 Summer Reliability Assessment, May 2022.
[104] NERC Summer Reliability Assessment at 5.
[105] *Id* at 29.

grid instability, and further increasing the need for firm load shed to avoid total grid failure; and 4) the loss of the affected generation will reduce the gross inertia capacity of the system by 13%. This will likely result in increased out of market instruction by ERCOT to maintain minimum amounts of inertia needed to maintain reliability (inverter-based generation, such as wind and solar, do not supply inertia).[106] Concerns about electric reliability will be exacerbated by this Proposed Rule. The marginal air quality improvement represented by this Proposal Rule in light of system deficiencies calls into question EPA's decision to engage in power generation shifting and idling. It is not apparent how EPA's generation shifting assumptions will play out in light of these reliability concerns. "The reality for the zones that do not have sufficient generation to cover their load plus their required reserves is that they will have increased risk of temporary, controlled outages to maintain system reliability," Clair Moeller, MISO's president and chief operating officer, said in a statement last month.[107] Moeller said further customers in those zones "may also face higher costs to procure power when it is scarce."[108] Efforts to comply with a final rule consistent with EPA's proposal would further strain public power, which is already under pressure from the cumulative impact of EPA and state rules. EPA recently issued proposed decisions on the first group of Coal Combustion Residual (CCR) Part A closure extension requests which will have profound effects on the electric utility sector, including public power utilities. Facilities that do not receive approvals of their Part A CCR closure extension request, will be given 135 days to cease the receipt of coal ash waste into surface impoundments. The loss of the disposal capacity could force affected facilities off-line potentially during the 2023

[106] ERCOT Board of Directors Meeting, "Item 6.1 ERCOT Analysis of Environmental Protection Agency (EPA) Federal Implementation Plan (FIP) Regional Ozone Transport Rule," June 21, 2022. https://www.ercot.com/files/docs/2022/06/17/6.1%20ERCOT%20Analysis%20of%20EPA%20FIP%20Regional%20Ozone%20Transport%20Rule.pdf.

[107] https://www.misoenergy.org/about/media-center/misos-annual-planning-resource-auction-results-underscore-the-reliability-imperative/.

[108] *Id*.

ozone season depending on when EPA issues its final CCR Part A determinations, thus exacerbating electric reliability concerns.

The regulatory incentive provided in the Proposed Rule to retire units by 2028 adds to this existing pressure. Moreover, flexibility is needed as the fleet transitions to increasingly less fossil-fuel-fired generation. When public power utilities lack capacity, they have to purchase power on the market. Market prices for electricity are already prohibitively high, due in part to the increasing ammonia costs, which is needed to run SCRs, and the high cost of natural gas.[109] Prices are likely to increase considerably if EPA issues a final rule consistent with its proposal.

A final rule that imposes state budgets at levels consistent with the stringency of the proposed state budgets also risks forcing unit shutdowns on a scale and schedule that will not allow the remaining fleet capacity to keep pace with electricity demands. This problem is driven in large part by the incorrect technical assumptions described previously and EPA's base case modeling assumptions. APPA commissioned a report to evaluate how EPA's Integrated Planning Model (IPM) v6 Summer 2021 Reference Case treated public power utilities, attached as Appendix 2.[110] Below is an excerpt showing public power operating coal capacity, amount of public power coal capacity idled by IPM in a run year, cumulative coal retirements modeled by IPM and IPM modeled coal to gas (C2G) conversions.

[109] *See* https://www.eia.gov/todayinenergy/detail.php?id=52358 (noting the U.S. price of ammonia has risen by a factor of six in the past two years; the cost of natural gas has also increased substantially).

[110] APPA_Summer 2021 Reference Case Analysis, James Marchetti, March 2021 (Appendix 2).

Year	No. Units	Public Power Operating Coal (MW)	Public Power Operating Coal Idled (MW)	Public Power Coal Retirements (MW)	Public Power C2G (MW)
2023	124	47,685	10,558	7,531	0
2025	124	46,000	9,712	8,749	336
2030	124	41,843	5,700	11,060	1,973

In the Reference Case, IPM idles over 20 percent of public power operating coal capacity in the 2023 and 2025 run years. The level of idled capacity drops in 2030, due to the increase in demand which is not able to be met by other types of generating resources. The level of idled capacity appears to decrease in 2025 and 2030 as idled units are brought back online or retired. Idling generation, as the Reference Case did, for multi-year periods and then restarting the units later is not a feasible solution. If a facility were to decide that a unit was uneconomic and therefore would not run for a multi-year period, it would be more likely that the unit would be fully decommissioned and never return to service. In terms of coal retirements, IPM models increasing coal retirements through 2030; whereby, 2030 the level of coal retirements would be equal to a quarter of public power's modeled operating coal capacity. Prior to the modeling the first run year (2023) in the Summer 2021 Reference Case, EPA removes announced retirements through 2023 from the simulation as shown in Tab 5.[111] These retirements seem to begin in 2020 and run through 2023. IPM has removed 2,397 MW of public power coal capacity and 581MW of gas capacity prior to the modeling. EPA should review and revise its Reference Case to reflect correction in which units will actually retire or become idle.

Based on these erroneous inputs and assumptions, the result of EPA's built-in assumptions is allocation of inadequate numbers of allowances to public power EGUs. EPA's

[111] *See,* APPA_Summer 2021 Reference Case Analysis, James Marchetti, March 2021, Tab 5, NEEDS_Retirments_2023.

proposals to limit use of Group 2 allowances banked prior to 2023 and to recalibrate the number of banked allowances available for use on an annual basis exacerbate this problem considerably. APPA members are very concerned they will not be able to buy Group 3 allowances, particularly as the bank is recalibrated, and that they will be left without a means to meet their customers' electricity demands and also comply with the rule. At the time these comments were submitted, CSAPR ozone-season NOx allowances were trading at up to $30,000 per ton, which is an exorbitant price for any utility, but astronomical for public power. EPA threatens to enforce penalties for noncompliance with the rule that could total millions of dollars per ton. APPA's members – not-for-profit, community-owned utilities – are not capable of paying penalties on this scale, and likely will not be able to handle the cost of compliance. The result will be electric reliability issues in the communities that they serve, some of which are environmental justice communities.

X. Conclusion

For the foregoing reasons, the Proposed Rule is defective on substantive and procedural grounds and should not be promulgated. If EPA intends to continue this fundamentally flawed rulemaking, it must at a minimum correct the numerous legal and technical problems with its Proposed Rule in a supplemental notice of proposed rulemaking and provide an adequate period for meaningful and comprehensive public review and comment of a new proposed rule. Should you questions regarding these comments please contact Carolyn Slaughter (CSlaughter@publicpower.org) or call 202-467-2900.

Appendix I

Technical Comments on Electric Generating Unit Control Technology Options and Emission Allocations Proposed by the Environmental Protection Agency in Support of the Proposed 2015 Ozone NAAQS Transport Rule (June 17, 2022), prepared by J. Edward Cichanowicz, James Marchetti, Michael C. Hein, and Shirley Rivera.

Technical Comments on Electric Generating Unit Control Technology Options and Emission Allocations Proposed by the Environmental Protection Agency in Support of the Proposed 2015 Ozone NAAQS Transport Rule

Prepared by

J. Edward Cichanowicz
Consultant
Saratoga, CA

James Marchetti
Consultant
Washington, DC

Michael C. Hein
Hein Analytics, LLC
Whitefish, MT

Shirley Rivera
R-CAT
Union City, CA

Prepared for the

Midwest Ozone Group
National Rural Electric Cooperative Association
American Public Power Association

June 17, 2022

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1. Summary of Flaws in EPA's Approach

The following is an abbreviated summary of flaws in EPA's analysis that are described in detail in the remainder of this report.

Cost Premises. EPA errs in assuming units to be retrofit with SCR will operate for 10 years, and does not adequately escalate cost from a 2021-dollar basis.

- EPA, by using a capital recovery factor of 0.142, implies a 10-year life for recovery of SCR capital cost, which lowers the calculated incurred cost per ton ($/ton) of NOx removed. It is possible that generating units will terminate operation before then. The cost incurred ($/ton basis) for a 5-year lifetime is shown in this report to be as much as double the cost incurred for a 10-year recovery.

- EPA adopts the Sargent & Lundy (S&L) cost premises to escalate costs from 2011 at 2.5% annually to 2021. The S&L cost methodology does not reflect the recent changes in material and labor cost which are continually evolving. The analysis in this report adopted S&L's approach through 2019, then employed the Chemical Engineering Equipment Cost Index (CEPCI) for escalation from 2019 through mid-2021.

Optimistic Control Capability of Advanced Combustion NOx Controls. EPA projects the achievable NOx emissions rate (lbs/MBtu basis) to the national fleet based on extrapolating NOx emission reductions achieved from select operating units, without proper regard for the role of fuel rank, fuel composition, and fuel variability, as well as furnace geometry in generalizing results.

Unrealistic Timeline Schedule for Retrofit of Combustion and SCR NOx Controls. EPA's assumption of less than 12 months as necessary for combustion control retrofit is unrealistic, and not supported by detailed submittals for 11 authentic recent installations. Similarly, EPA's assumption of a timeline supporting retrofit of SCR to approximately 100 units in less than 36 months is unrealistic, and not supported by authentic experience for 25 recent installations. Industry experience as detailed in this report suggests that 60 months may be appropriate to enable most units to deploy SCR.

Incorrect Cost Metric for Existing SCR-equipped Units. For units presently equipped with SCR, the proposed rule extracts incremental reductions in NOx from the baseline of 2021 emissions – but does not calculate the increment in cost exclusively for this action. Rather, EPA presents a "revisionist" cost of the initial SCR NOx retrofit project, determining the cost to achieve 0.08 lbs/MBtu from the historical boiler NOx rate. The metric EPA uses is incorrect, as it blends the control cost for the present action with the initial decision to deploy SCR, lowering the apparent cost.

<u>Inaccurate Capital, Operating Cost for SCR Retrofit</u>. The capital charge is to be adjusted to reflect a rationale number of installations that will employ and Engineer Procure Construct (EPC) approach, and (b) properly account for catalyst management costs for high-performing applications.

<u>Daily Backstop Rate</u>. EPA's daily backstop rate of 0.14 lbs/MBtu, as presently proposed, will penalize even well-run SCR processes, as NOx emissions emerging from startup show the proposed rule will prompt for even well-run units some operating days above this rate. The analysis in this report shows any unit undergoing a startup will unavoidably exceed the rate as proposed. Further, an owner – by avoiding a shutdown to repair a malfunction – could compromise the ability to meet a targeted SCR exit rate, in order to avoid exceeding the backstop rate.

<u>Grid Operability May Not Support Generation Shifting.</u> EPA's introduction of generation shifting as a "control step" is unrealistic. EPA assumes there are no barriers to the movement of power within a state, when in fact the design and operation of the power delivery grid frequently dictates movement of energy. Further, some of the energy EPA requires to be shifted within a state must cross boundaries of more than one Regional Transmission Operators (RTO), comprising an energy transfer rarely executed. This need to support grid reliability is even more important as new generation sources evolve, and both renewable and natural gas fired combined cycle generation in planned and constructed.

<u>EPA Needs to Revise the State Budgets</u>. Due to omissions and errors, the state budgets calculated by EPA need to be revised, in order to prevent reliability concerns beginning in 2023. Some provision that comprises a 'reliability off-ramp" should be included that allows unit operation without the requisite allowances, when grid reliability is challenged.

<u>Generation Shifting Step in the State Budget Setting Process Should be Eliminated</u>. The basis of this step is flawed. The Base Case used in the Generation Shifting modeling is inaccurate and leads to erroneous modeling results.

2. Introduction

The Environmental Protection Agency (EPA) proposal for a revised Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard (Cross-State Air Pollution Rule for the 2015 Ozone NAAQS) is premised on cost and performance capabilities of NOx emission control technology. EPA claims to have considered realistic assumptions defining NOx control capabilities and cost in their analysis. These assumptions are reported by EPA in the Technical Support Document (TSD)[1] where EPA presents costs, emission reduction potential, and their assessment of feasibility related to the emission control strategies.

Many of these assumptions are flawed. EPA "mines" actual ozone season NOx emissions data from prior years, but does not properly interpret this information or consider the site-specific nature of boiler operation and coal type as it generalizes data over the entire fleet. Market conditions must be considered for these operating periods, especially for merchant generators. EPA's approach lacks authentic insight as to design and operating conditions.

This report critiques key EPA assumptions used the technical and cost analyses for electric generating units that supports the propose rule.

Section 3 presents the inventory of electric generating units explored in this evaluation. Section 4 overviews combustion control technology, critiquing EPA's assumptions addressing NOx emission control capability and the time required to retrofit new emission controls. Section 5 critiques EPA's assumption for cost evaluation of postcombustion controls, and proposes inputs that are more realistic. Section 6 presents results of the analysis for this study addressing the incurred cost-per-ton ($/ton) of control actions. Section 7 summarizes statistical evaluation of 110 high-performing SCR-equipped units, providing insight to the impact of the proposed daily backstop rate.

Section 8 addresses the Generation Shifting element of EPA's proposal, presenting a detailed data analysis for nine example states demonstrating the flaws in EPA's analysis, and the challenges of balancing the shifts in generation for affected units. A summary of the errors and challenges due to the EPA's assessment of NOx state budgets and compliance for the nine example states is presented in Section 9.

Appendix A presents maps for the nine states evaluated for impact of generation shifting, that identify and show the location of the stations projected by EPA to be most affected. Appendix B summaries the public information available regarding unit announced retirements.

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[1] Technical Support Document (TSD) for the Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard, Docket ID No. EPA-HQ-OAR-2021-0668. February 2022. Hereafter EGU TSD.

3. Generating Unit Inventory

3.1 Inventory: This Study

Section 3 describes the inventory of the units in the 25-state region, accounting for differences in unit inventory between this study and EPA. For example, in the evaluation of SCR retrofit, EPA includes the electric generating units in the 25 states applicable to the program, and an additional 38 units in 10 other states. These additional units are not to be representative of the units in the 25 states and distort the incurred cost per ton for the units in the 25 states included in the proposed rule. EPA did not justify inclusion of the additional states in the 25-state evaluation.

Figures 3-1 and 3-2 present basic metrics of the generating units in the 25 states. Figure 3-1 reports the number of coal-fired boilers, coal fluidized bed steam boilers, and oil/gas boilers within the 25 states, showing approximately 340 coal-fired steam generators and 200 oil/gas-fired steam generators. The bar chart also reveals the partitioning of units above and below the 100 MW capacity threshold proposed by EPA to designate oil/gas-fired units that could be required to deploy SCR. The 100 MW threshold potentially exposes 150 oil/gas-fired units to retrofit SCR, depending on if their ozone season NOx emissions exceeds 150 tons.

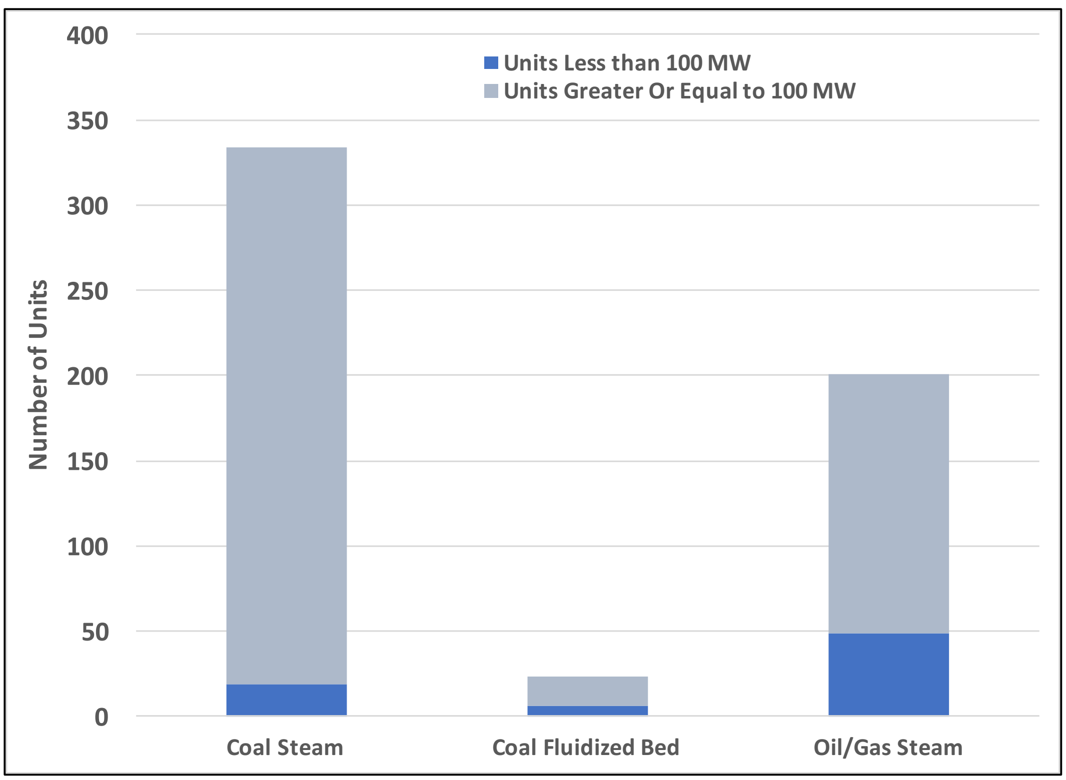

Figure 3-1. Inventory of Boilers in the 25 State Region

Figure 3-2 presents the number of units presently equipped with either SCR or SNCR within the 25-state inventory. Regarding coal-fired units, a total of 169 are presently equipped with SCR with an additional 43 featuring SNCR. In reference to units fired by oil and/or natural gas, nine are equipped with SCR while 17 are equipped with SNCR.

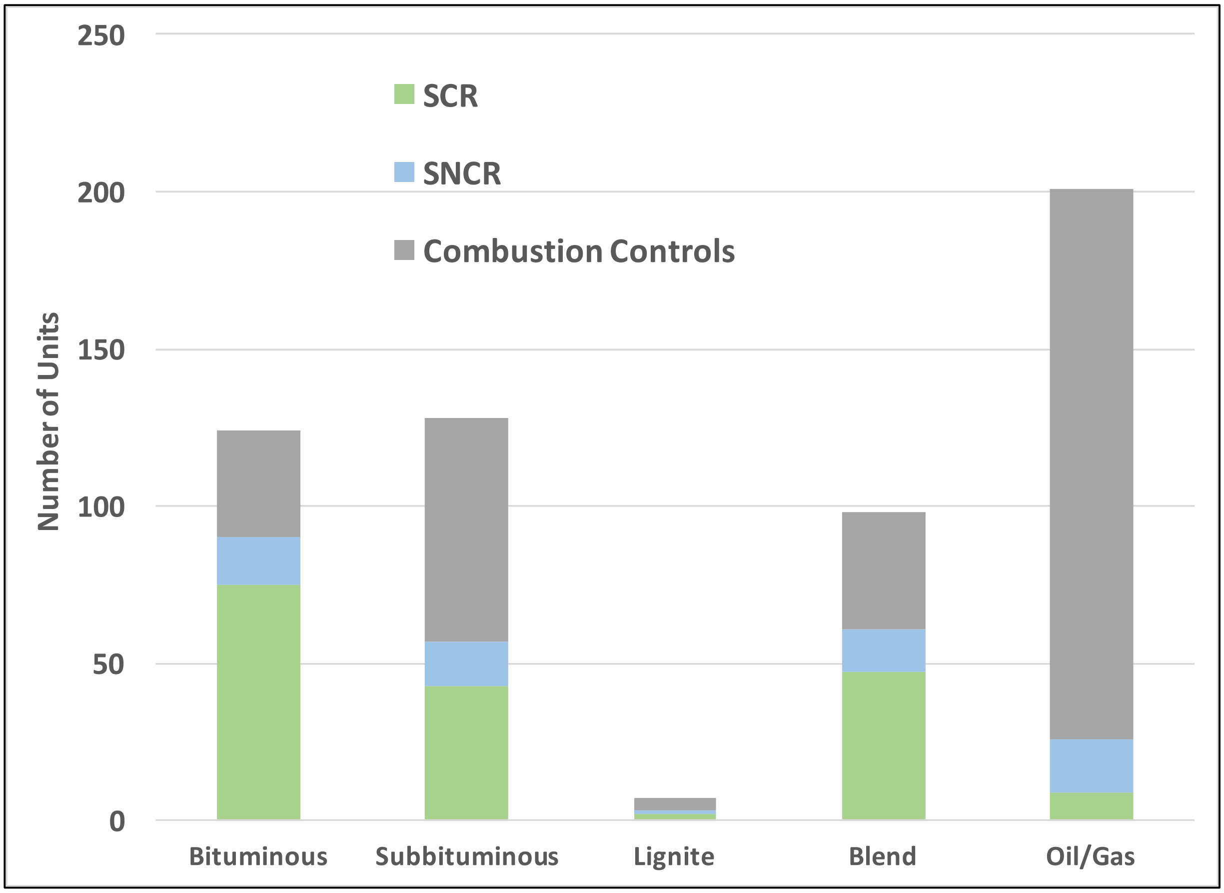

Figure 3-2. Inventory of Boilers in the 25 State Region

Figure 3-2 also reports units featuring solely combustion NOx controls; there are 34 that fire bituminous coal, 71 that fire subbituminous coal, 37 that fire a blend of bituminous and subbituminous, and four that fire lignite. Consequently, in the 25-state region a total of 146 coal-fired units could be considered as candidates to retrofit SCR.

The cost evaluation presented in this analysis is based on the boiler inventory as described above.

3.2 Inventory: Units without SCR

Table 3-1 compares the inventory of units not equipped with SCR that are candidates for retrofit, for both the coal-fired and oil/gas-fired categories, as interpreted by both EPA and the MOG/NRECA/APPA study (This Study).

Table 3-1. Inventory of Units Considered for SCR Retrofit: Coal and Oil/Gas Fired

Fuel	Candidate Units	Candidates That Meet Criteria	Units in non-study states	States Beyond 25
EPA				
Coal	204	126	38	AZ, CO, FL, IA, KS, MT, NC, ND, NE, WA
Oil/Gas	166	78	14	AZ, CT, FL, IA, MA, ME, NM
This Study				
Coal	229	94		
Oil/Gas	142	36		

As Table 3-1 shows, for coal-firing, EPA considered 204 units with 126 meeting the selection criteria in all states.[2] EPA included in this total of 126 units an additional 38 units in 10 additional states, with 85% of units in the latter firing subbituminous and lignite coal compared to 75% within the 25-state region. The additional 38 units feature lower cost per ton of NOx removed by approximately 11% - imparting significant bias to the 25-state region.

For oil/gas firing, EPA considered 166 units with 78 meeting the selection criteria[3] in the 25 states. A total of 14 additional units are introduced into the database from 7 additional states.

This study considered for coal-firing a total of 229 units, of which 94 meet the inclusion criteria (and approximating the 88 units considered by EPA). For oil/gas firing this study considered 142 units as candidates, identifying 36 that met the criteria in the 25 states.

3.3 Inventory: Units with SCR

Table 3-2 compares the inventory of units equipped with SCR for both coal-fired and oil/gas-fired categories, as considered by both EPA and for work reported for this study. As Table 3-2 shows, for coal-firing, 226 units are considered by EPA with 172 meeting the selection criteria in all states. EPA included in this total an additional 46 units in nine additional states.

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[2] Generating units were considered with a "nameplate" rating of 100 MW or greater, and emitted more than 0.14 lbs/MBtu.

[3] Electric generating units – per EPA's proposal - are required to retrofit SCR if the unit "nameplate" generation is rated for 100 MW or greater.

Table 3-2. Inventory of Units Equipped With SCR: Coal and Oil/Gas Fired

Fuel	Candidate Units	Candidates That Meet Criteria	Units in non-study states	States Beyond 25
EPA				
Coal	226	172	46	AZ, FL, GA IA, KS, MT, NC, NH, and SC
Oil/Gas	20	16	5	CA and MA
This Study				
Coal	175	77		
Oil/Gas	11	0		

For oil/gas firing, EPA identified 20 candidate units of which 16 meet the selection criteria in the all states. Five additional units are introduced into the database from two states.

This study considered 175 SCR-equipped coal-fired units, of which 77 meet the inclusion criteria[4] (approximating the 88 units considered by EPA). The inventory of units in this study is smaller than EPA, as this study considered only the 25 states subject to the proposed rule. Consistent with a correct interpretation of marginal cost, this study examined only units in the 2021 ozone season that emitted NOx at greater than 0.08 lbs/MBtu - such units already complying with the target value would not require additional actions and incur a marginal cost. This is in contrast to EPA's approach of conducting a "revisionist" calculation of compliance cost, using the from the boiler NOx outlet rate to define the NOx removal.

For oil/gas firing, this study considered 11 units as candidates; none were identified to meet the criteria in the 25 states.

[4] Similar to coal-fired units, a nameplate capacity of 100 MW or greater and 2021 NOx emission rate of 0.14 lbs/MBtu.

4. Combustion Control Capability

4.1 Introduction

EPA over-estimates the capability of advanced combustion controls to limit boiler NOx emissions to extremely low rates (per lbs/MBtu). EPA appears to define advanced combustion controls as some combination of low NOx burners and overfire air, both of which delay or "stage" the combustion process to create NOx-reducing regimes with a flame. EPA does not offer any other definition of advanced technology, but appears to treat a unit that emits NOx at greater than 0.25 lbs/MBtu as not equipped with advanced technology.[5]

Specifically, EPA notes in the EGU TSD:[6]

> *Modern combustion control technologies routinely achieve rates of 0.20 – 0.25 lb NOx/MMBtu and, for some units, depending on unit type and fuel combusted, can achieve rates below 0.16 lb NOx/MMBtu.*

The NOx emission rates cited by EPA as attainable are based on fuel composition that cannot be extrapolated to the national inventory. EPA does not recognize – especially for tangential-fired boilers firing bituminous coal – these reference fuels are atypical. Consequently, EPA does not acknowledge the error inherent in generalizing NOx emission rates from a small subset of boilers to the national inventory. Further, EPA did not conduct a detailed cost evaluation of combustion controls; rather EPA used costs derived from a 2011 study that is part of IPM documentation[7] for which reference data is not shared. Rather, EPA cites calculations using a static spreadsheet-based evaluation that determines total (not incremental) costs for an "illustrative unit" [8] to be less than $1,600/ton.

4.2 Referenced Units

EPA identified 53 tangential-fired units and 39 wall-fired units equipped with advanced combustion controls. Figures 4-1 depicts for the EPA reference tangential-fired boilers the 2021 ozone season average of NOx emissions as reported to EPA. Figure 4-2 depicts the 2021 ozone season NOx average for the EPA reference wall-fired boilers. EPA proposes these units typify candidate units in the national fleet. This assumption is in err.

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[5] EGU NOx Mitigation TSD, page 14.

[6] Ibid.

[7] https://www.epa.gov/sites/default/files/2015 07/documents/chapter_5_emission_control_technologies_0.pdf. Table 5-4.

[8] Ibid, page 16 and footnote #23, 24.

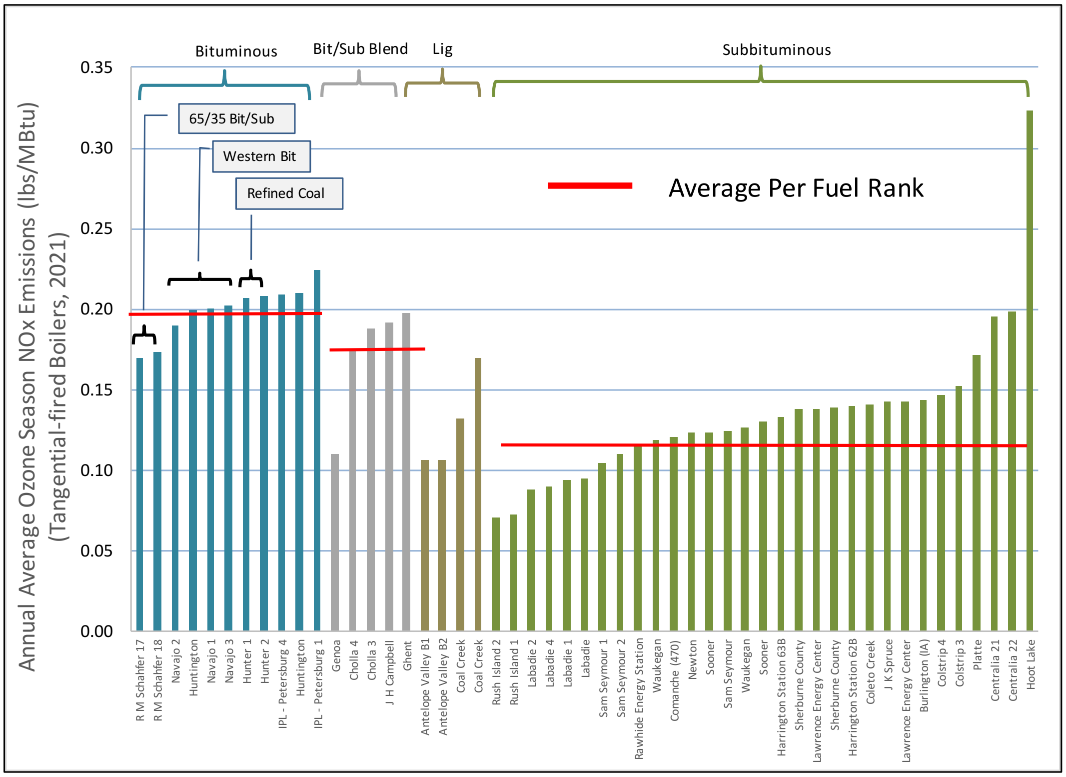

Figure 4-1. 2021 Average Ozone Season NOx Emissions: Tangential-Fired Boilers Firing Bituminous, Subbituminous, Blends and Lignite Coals

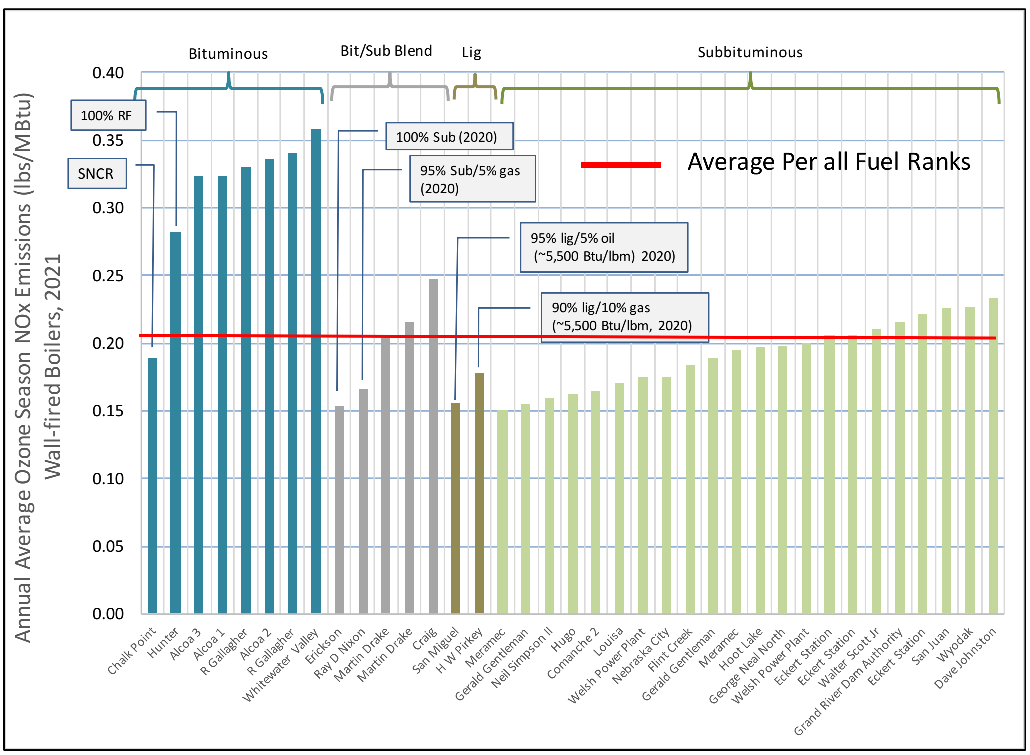

Figure 4-2. 2021 Average Ozone Season NOx Emissions: Wall-Fired Boilers Firing Bituminous, Subbituminous, Blends and Lignite Coals

Success with combustion controls requires several boiler characteristics: generous surface area adjacent to the burners for heat removal, generous burner spacing, and adequate distance to "stage" the combustion process with overfire air ports. That the EPA candidate boilers are retrofit with such controls – in lieu of others units in the fleet - suggests these units offer the physical features for successful combustion staging, and control of NOx. The reference units in Figures 4-1 and 4-2 may not represent other boilers in the national fleet. Extrapolating combustion control capability as described by EPA requires a thorough analysis to define these characteristics for the domestic boiler fleet.

4.2.1 Tangential-Fired Boilers

Figure 4-1 reports NOx data for 11 tangential-fired units designated by EPA as firing bituminous coal, with the results suggesting approximately 0.20 lbs/MBtu as achievable. This depiction is inaccurate, as the fuels as reported by EPA as bituminous are misleading. Based on EIA Form 860 data for 2020, the RM Schaffer units fire a bituminous/subbituminous blend. The Navajo and Hunter units fired western bituminous – the composition of which lacks the sulfur content and acid/base ratio of eastern bituminous coals that are problematic in achieving the deep staged conditions required for low NOx. Also, differences in coal nitrogen content and the inherent volatility assert an impact. The Hunter units fire a refined variant of bituminous coal – an option not available in 2022. Only IPL-Petersburg Units 1 and 4 fire an authentic bituminous coal of composition that could be considered representative of U.S. fuels. Further, EPRI estimates the median value of NOx emissions from tangential-fired boilers firing bituminous coal to be 0.35 lbs/MBtu for LNCFS-II and 0.34 lbs/MBtu for LNCFS-III, with values for the latter option as high as 0.47 lbs/MBtu.[9] This information – albeit derived from a 2003 summary –reflects the present status of technology cited by EPA, as the NOx emission rates less than 0.10 lbs/MBtu were publicly cited in 2000.[10]

Data is also shown for five units firing a bituminous/subbituminous blend, two lignite–fired units, and 32 subbituminous-fired units. Almost all subbituminous coals are from the Power River Basin (PRB), which due to high fuel volatility and excess alkalinity enable "deep" staging conditions that support low NOx. PRB moisture content can be four times the moisture content of bituminous, with half the nitrogen content – both important factors. The extremely low NOx emissions (< 0.10 lbs/MBtu) observed on units at the Rush Island and Labadie stations are achieved with favorable volatility by even PRB standards. It is unreasonable to assume that PRB coal or PRB-like coal with these properties can be broadly acquired, thus their role establishing an average NOx rate should be discounted.

4.2.2 Wall-Fired Boilers

Figure 4-2 reports NOx data for eight wall-fired boilers EPA cites as firing bituminous coal, with the results suggesting NOx emission less than 0.20 lbs/MBtu as achievable. As noted

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[9] EPRI 2002 Workshop on Combustion-Based NOx Controls for Coal-Fired Boilers, EPRI Report 1007579, January 2003. Hereafter EPRI 2002 Workshop. See page 2-96.

[10] Neural Networks Prove Effective at NOx Reduction, NS Energy, May, 2000. Available at https://www.nsenergybusiness.com/features/featureneural-networks-prove-effective-at-nox-reduction/

previously, these units likely offer physical features that enable high performance of combustion controls – generous surface area per unit volume for heat release, burner spacing, and adequate distance to allow separation of overfire air and elongated flame length.

Regarding the eight bituminous fired units, the two lowest NOx emitting units are not further considered due to aberrant control technology or fuel type. Specifically, Chalk Point employs SNCR as a supplementary control step and Hunter fires 100% refined coal. Refined coal is not an option available in 2022 and beyond and is not considered representative. The remaining units are too small in generating capacity to register significance for the national fleet. Three units are extremely small, limiting their ability to confidently scale results to larger capacities - two R. Gallagher units are each 140 MW and Whitewater Valley is 35 MW. The three Alcoa units – each at 166 MW – are also of generating capacity not representative of the national fleet of wall-fired boilers. EPRI estimates the median value of NOx emissions from wall-fired boilers firing bituminous coal and employing LNB with OFA to be 0.36 (for opposed wall firing) to 0.40 lbs/MBtu (for single wall-firing), with values as high as 0.46 lbs/MBtu observed.[11]

Five units are referenced firing a blend of bituminous/subbituminous. The lowest NOx-emitting unit (Erickson) does not fire a blend of coal but rather 100% subbituminous; the next lowest NOx emitting unit (RD Nixon) fires a blend of subbituminous and natural gas. The two Martin Drake units are 75 and 132 MW, respectively.

As acknowledged previously, subbituminous coal enables low NOx firing conditions, particularly for coals with high volatility. The lowest emitting units are small – Neal Simpson II (90 MW) and are not representative.

<u>Takeaway</u>. For both tangential and wall-fired boiler, EPA's projected NOx emission rates are based on atypical fuels and unit design and are not representative of the national fleet. Many owners have already retrofit combustion controls with advanced mixing and some degree of overfire air, and thus already are equipped with the essentials of advanced control technology. One owner (LG&E/KU) through 2014 has retrofit eleven generating units with some form of advanced control technology, eliciting supplier guarantees ranging from 0.21-0.37 lbs/MBtu.[12]

The most significant error in EPA's methodology concerns bituminous coal, in which western bituminous or refined coals are wrongly cast as representing conventional bituminous. In addition, extrapolating results from units less than 200 MW to the national inventory is not straightforward and requires considering factors such as furnace surface area, combustion product flow volume, and distance available over which to mix fuel and air. The extrapolation of subbituminous–fired results must also be executed with caution, as even PRB volatility – which affects NOx control performance –can widely vary.

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[11] Ibid. See page 2-93.

[12] Personal Communication, LG&E and KU Energy LLC Staff: June 15, 2022.

4.3 Generalizing Results to Boiler Population

The results highlighted by EPA are not readily generalized over the 25 states due to variations in fuel composition, fuel characteristics, and boiler type. EPA's assumptions are flawed in terms of the ability to reach the low levels of NOx cited in the previous figures.

4.3.1 Fuel Composition

EPA does not consider the role of coal composition and characteristics, or the design "vintage" of the boiler on the performance of combustion controls and resulting NOx emissions. Each of these factors is addressed below:

The composition and characteristics of fuel drive NOx control capability with coal – most notably from PRB. 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.[13]

NOx control capability is greatest when liberated fuel-bound nitrogen is exposed to oxygen-deficient conditions for the longest residence time. PRB coal presents a second advantage in maximizing oxygen-deficient conditions while avoiding boiler watertube corrosion. In contrast, these 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.[14] 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 and nitrogen content, combined with high inorganic alkaline content, minimizes the production of corrosive species thus enabling PRB-fired burners to exploit low NOx conditions, but such options are not available to the general population of units in the 25-state region and are not representative of the fleet as a whole. Therefore, EPA's failure to distinguish characteristics of coal used in its analyses results in a generalization that distorts its conclusions.

4.3.2 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

[13] *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.

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

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 4-3 presents a general boiler layout used to define the BZLR for the four major boiler suppliers.[15] Prior to concerns for NOx reduction, BZLR was selected 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.[16] This change in BZLR was prompted by the need to lower flame temperature to minimize thermal NOx and provide space for low NOx burners and the associated extended-length flames. The most recent boiler designs employ relatively low BZLR to achieve these NOx rates.

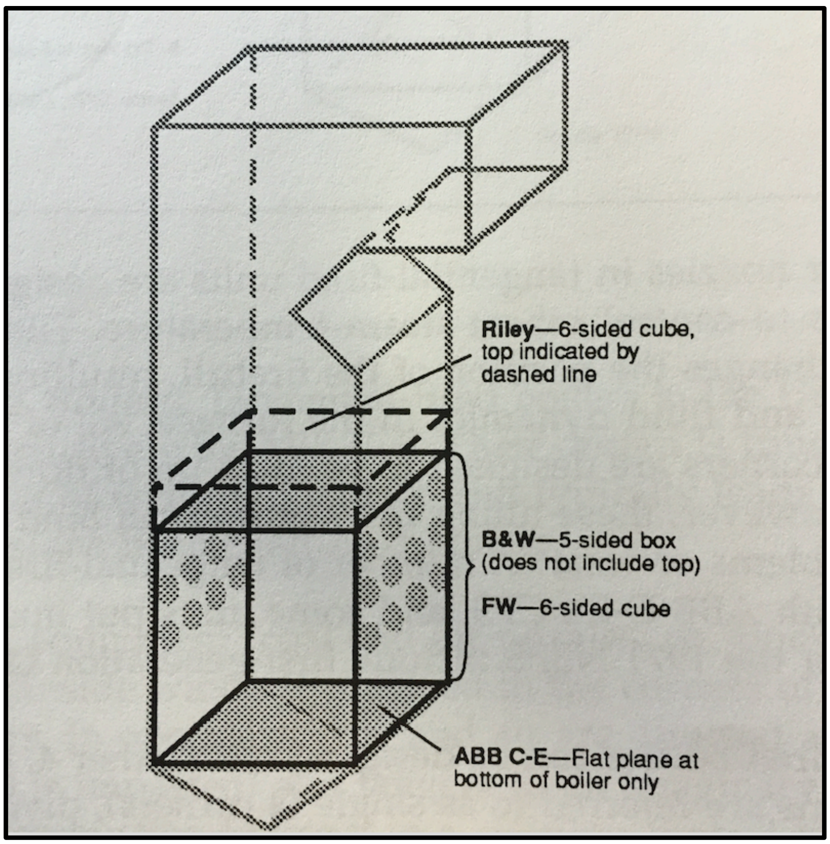

Figure 4-3. Definition of Burner Zone Liberation Rate: Four Major Boiler Suppliers

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 4-4 depicts the evolution of advanced boiler technology by one supplier (B&W), showing the progress achieved in recent

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

[16] 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.

decades with both subbituminous and bituminous coals. None of these systems achieves the lowest NOx rates, reported by EPA in Figures 4-1 and 4-2 as less than 0.10 lbs/MBtu.

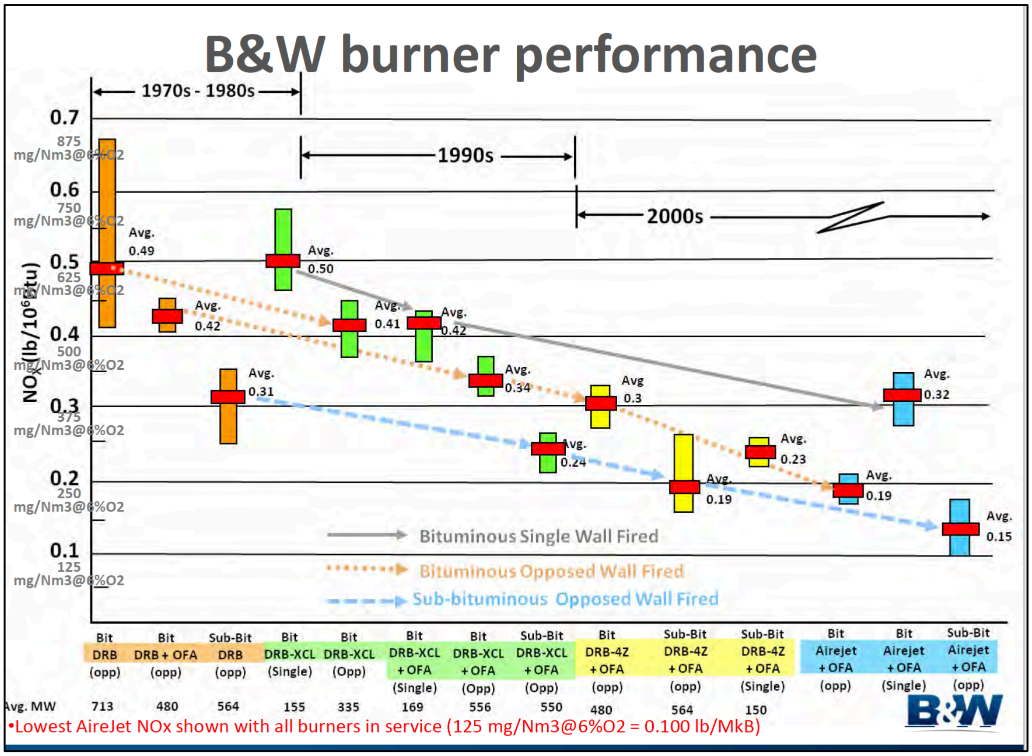

Figure 4-4. Wall-Fired Boiler Experience with Evolving Low NOx Burner Technology

4.3.1 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.[17] 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.[18]

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[17] The supplier of tangential-fired boiler technology commercial terminology for advanced combustion controls is the Low NOx Concentric Firing System, or LNCFS. There are three variant or "levels" of this technology, defined as LNCFS-1, LNCFS-2, and LNCFS-3.

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

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.

4.4 Revised Control Capability, Cost

Revised NOx control performance and cost are presented in this subsection.

Advanced combustion controls are capable of reducing NOx by replacing 'legacy' burners in existing units – but not to the extent envisioned by EPA. The data presented in Figures 4-1 and 4-2 represents favorable fuel and furnace arrangement – and do not reflect the domestic fleet. The NOx emission rates cited in the EPRI survey represent a second rationale source.

The NOx emission rates in Table 4-1 represent values from the domestic fleet that account for the variability in fuel composition and firing equipment. These values represent averages of the high and low values, and thus consider data in Figures 4-1 and 4-2 while accounting for units that due to fuel and equipment limitations achieve the higher NOx emission rates.

Table 4-1. Average Achievable NOx Emissions Rates

Coal Rank	Tangential-Fired	Wall-fired
Bit	0.30	0.32
Lignite	0.20	0.22
PRB	0.15	0.19

Regarding the cost of combustion controls, the EGU TSD notes:[19]

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

A simple analysis shows these costs to much higher. Using the capital, fixed O&M, and variable O&M from Table 5.4 of the IPM 5.13 documentation,[20] the total cost of deploying advanced low NOx firing equipment to a tangential-fired and wall-fired 300 MW boiler operating at 10,000 Btu/kW and a 56% capacity factor is $3,345,200 and 2,055,529 dollars (2021 basis). For the wall-fired boiler, lowering NOx for bituminous firing from 0.40 to 0.30 lbs/MBtu incurs a cost of $4,506/ton, while for PRB using these means to lower NOx from 0.30 to 0.19 lbs/MBtu incurs a cost of $4,132/ton. For the Tangential -fired boiler, lowering NOx for bituminous firing from 0.35 to 0.25 lbs/MBtu incurs a cost of $2,793/ton, while for PRB using these means to lower NOx from 0.22 to 0.15 lbs/MBtu incurs a cost of $3,990/ton. The $1,600/ton referenced by EPA for widely available controls and cost effectiveness is biased due to unrealistic input assumptions, and bears no resemblance to our analysis.

[19] EGU TSD, see page 10.

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

4.5 Installation Schedule

EPA's actions are premised on owners being able to complete installation of new combustion hardware within a time frame that allows compliance with the 2024 ozone season NOx rates - basically, less than 12 months from this report date. EPA's basis for this assumption is not strong -– EPA cites an 11-year old document[21] purported to reflect the hardware requirements of state-of-art-combustion controls. However, this document cites only two installations, each of which reported retrofit in 6 months.

Table 4-2 reports retrofit experience of significantly more than two units – six owners, eight stations and eleven boilers. Table 4-2 presents significant detail, reporting not just total time from project conception and preparation through startup, but the specifics of time required for major steps. The present issues of labor shortages and supply chain disruption are not reflected ibn Table 4-2, and will further extend project schedules. Table 4-2 shows that on average 22 months is required to complete the entire project scope – suggesting at best that if project conception started immediately, a large fraction of these units could be ready for the 2025 ozone season.

EPA proposes "Step 2" of the compliance process for all units equipped with postcombustion controls to first 'optimize' the compliance process by adopting advanced combustion controls. The time required for such actions presents Step 2 from being practically achieved, and is not considered feasible (and this not further addressed in this report).

Takeaway: EPA's projection of low NOx emission rates is flawed, particularly for bituminous coal, as only three units are valid references while others represent atypical cases of western bituminous, refined coal, or are co-fired when reported as exclusive bituminous. Only newer generating units that feature relatively low Burner Zone Liberation Rates could replicate the claimed low NOx conditions; many boilers designed for NOx New Source Performance Standards (NSPS) prior to 1997 or for a narrow range of coal properties will be challenged unlikely to achieve these rates. In summary, EPA's projection of the NOx control capability of advanced combustion controls is flawed as it does not fully consider coal rank, boiler design features, and operating characteristics. As a result, the incurred cost per ton of NOx removal is higher, due to lower mass of NOx removed.

The time required for installation – an average of 22 months based on a survey of 11 boilers - significantly exceeds the time available to enable retrofit for the 2023 ozone season. Notably, the 22-month is an average – one public power entity incurred between 48-60 months for the entire scope of activities, including arranging financing (required prior to any significant actions) and regulatory approval prior to installation to achieve cost recovery. Merchant generators will not require such approval, but are required to justify the need with certainty to a lender.

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[21] Installation timing for Low NOx burners (LNB), Technical support Document for the Transport Rule, docket ID No. EPA-HQ—OAR-2009-0491.

Table 4-2. Combustion Control System Acquisition, Installation Time

Owner	Units	Equipment Scope	Project Duration (Months)	Required Outage (Days)	Details of Timeline (Months)
Ameren	Rush Island 1, 2	LNCFS Level 3 (from LNCFS Level 1)	31/35	75	Engineering: 10 Fabrication: 5 Installation: 6
APS	Cholla 1	LNCFS Level 2 (from LNCFS Level 1)	22	46	N/A
	Cholla 2/3/4	Same as above	26/28/35	39/57/54	N/A
Duke	Roxboro	LNB, digital control system	18	60	Prep: 2; Bid 2 Fabricate: 12; Install 2
	Lee 1, 2	Separated OFA	18	60	N/A
SRP	Coronado 1, 2	LNB/OFA	21/20	49/42	Prelim:6; Proposal: 3 Final design:3; Fabrication:7 Installation: 2
We Energies	Oak Creek	LNCFS 3 (From LNCFS Level 2)	24		22 months once contract final
	Valley	LNB	20		22 months once contract final
Midwestern		LNB, OFA (TFS 2000)	15-18	90-100	N/A

5. POSTCOMBUSTION NOx CONTROL

Section 5 presents comments on EPA evaluation of the feasibility and cost effectiveness of both SCR and SNCR NOx control.

5.1 Selective Catalytic Reduction (SCR)

The EPA proposes requiring additional NOx reduction from units presently equipped with SCR, and retrofitting SCR to units equipped to date with combustion controls or SNCR. This section reviews the technical and cost premises EPA adopts to support their actions.

5.1.1 Performance Basis

EPA's assumes owners of existing SCR–equipped units are not "fully operating" this process equipment to the maximum capabilities, extracting only that NOx required to meet the present standard or allowance position.[22] Whiles possibly true in some cases, EPA's estimate of additional capabilities for the costs is flawed.

EPA submits any unit's maximum NOx removal potential is demonstrated by the "third-lowest" ozone season emission rate observed since 2012. In practice, this methodology reflects only a snapshot in time of a unit's performance. It is well-known NOx control performance degrades with the state of the catalyst, and ability to maintain a uniform mixture of ammonia reagent with NOx generated in the boiler. A "third-lowest" NOx emission rate could reflect the immediate benefit of the exchange of catalyst and the increase in catalyst activity; EPA's analysis does not account for this possibility. Both the physical state of the catalyst and the ability to achieve a high degree of ammonia-to-NOx uniformity will degrade with time, and change year-to-year. EPA is in error to assume such NOx rates can be indefinitely attained from existing equipment – or, attained but with additional capital expenditure to refresh the catalyst inventory, or incur higher variable operating and maintenance (O&M) cost that projected by EPA. This analysis will assess NOx emission rates that are broadly achievable with SCR, requiring for some units either enhanced O&M practices and (in limited cases) capital improvement.

A further premise of EPA's propose rule is that present-day state-of-art SCR reactors retrofit to existing units can achieve ozone season NOx rates of 0.05 lbs/MBtu. A review of NOx emissions data from SCR-equipped units examined in this study shows 17 units averaged NOx emissions of less than 0.05 lbs/MBtu in the 2021 ozone season. A statistical evaluation of these NOx outlet rates shows for almost half of operating time (47%) NOx emissions range between 0.04—0.05 lbs/MBtu, with the remaining time distributed at rates both below and exceeding the 0.05 lbs/MBtu target value. As to be discussed, the cost per ton of NOx removed for such deep NOx removal can be exorbitant, if boiler exit emissions are less than 0.15 lbs/MBtu.

[22] EGU-TSD. Page 2.

5.1.2 Cost Basis

The cost basis for SCR is addressed both for retrofits and to units presently so-equipped.

New SCR Retrofit. EPA's evaluation of the feasibility for "widespread" implementation of SCR employs a cost estimating procedure issued by Sargent & Lundy that reflects both capital and operating cost.[23] The capital cost-estimating procedure – although an improvement over past methodologies applied by EPA in rulemaking – does not adequately capture retrofitting SCR into the remaining units in the coal-fired fleet. S&L note that cost components are derived from surveys and analysis conducted by *the authors of this document* over the time from as early as 2004 and through 2013, with these data "significantly augmented' by S&L in-house data.[24] The transparency in the source data is appreciated. However, *the authors of this document* submit that such costs are outdated and most relevant to early SCR installations, whereas candidate units in the remaining inventory differ in layout and baseline NOx emissions.

The analysis presented in this document will employ an adjusted version of the capital cost relationship proposed by S&L and utilized by EPA, as depicted in Figure 5-1 for the three coal ranks and including a relationship for oil/natural gas firing. This SCR capital cost relationship is derived from the "Retrofit-Cost-Analyzer-Update-1-26-2022".

Figure 5-1 shows the cost correlation well-reflects four estimates recently prepared for project participants. That a factor-of-two variation observed between several of the estimates (Flint Creek, Craig Unit 3) is not unusual –industry experience shows such variations are not uncommon, due to varying site conditions. (Such variations are the rationale for the "Retrofit Factor", subsequently described).

Figure 5-1 presents SCR capital costs for units firing these three ranks of coal. The SCR process conditions and the percent NOx removal required are inputs to the Retrofit-Cost-Analyzer-Update-1-26-2022 to generate capital cost. For bituminous units, a boiler NOx rate of 0.32 lbs/MBtu is assumed, targeting 85% reduction. For both PRB and lignite fuel ranks, a boiler NOx rate of 0.22 lbs/MBtu is assumed, targeting 80% NOx reduction

Also included in Figure 5-1 is a cost of $25/kW assumed necessary for pre-2005 SCR reactors to refurbish existing catalyst, retrofit enhanced catalyst cleaning devices (to remove accumulated fly ash deposits), and where necessary retrofit improved reagent mixing and flue gas rectification hardware (to improve flow velocity entering the SCR reactor). These or similar modifications will be necessary for pre-2005 SCR reactors to accommodate the changes proposed by EPA.

[23] IPM Model – Updates to cost and Performance for APC Technologies, SCR Cost Development Methodology for Coal-fired boilers, Final Report for Project 13527-002, February 2022.

[24] Ibid. See page 1. The 2004 to 2006 industry cost estimates for SCR units from the "Analysis of MOG and LADCO's FGD and SCR Capacity and Cost Assumptions in the Evaluation of Proposed EGU 1 and EGU 2 Emission Controls" prepared for Midwest Ozone Group (MOG) were used by Sargent & Lundy LLC (S&L) to develop the SCR cost model. In addition, S&L included data from "Current Capital Cost and Cost-effectiveness of Power Plant Emissions Control Technologies" prepared by J. E. Cichanowicz for the Utility Air Regulatory Group (UARG) in 2010 and 2013.

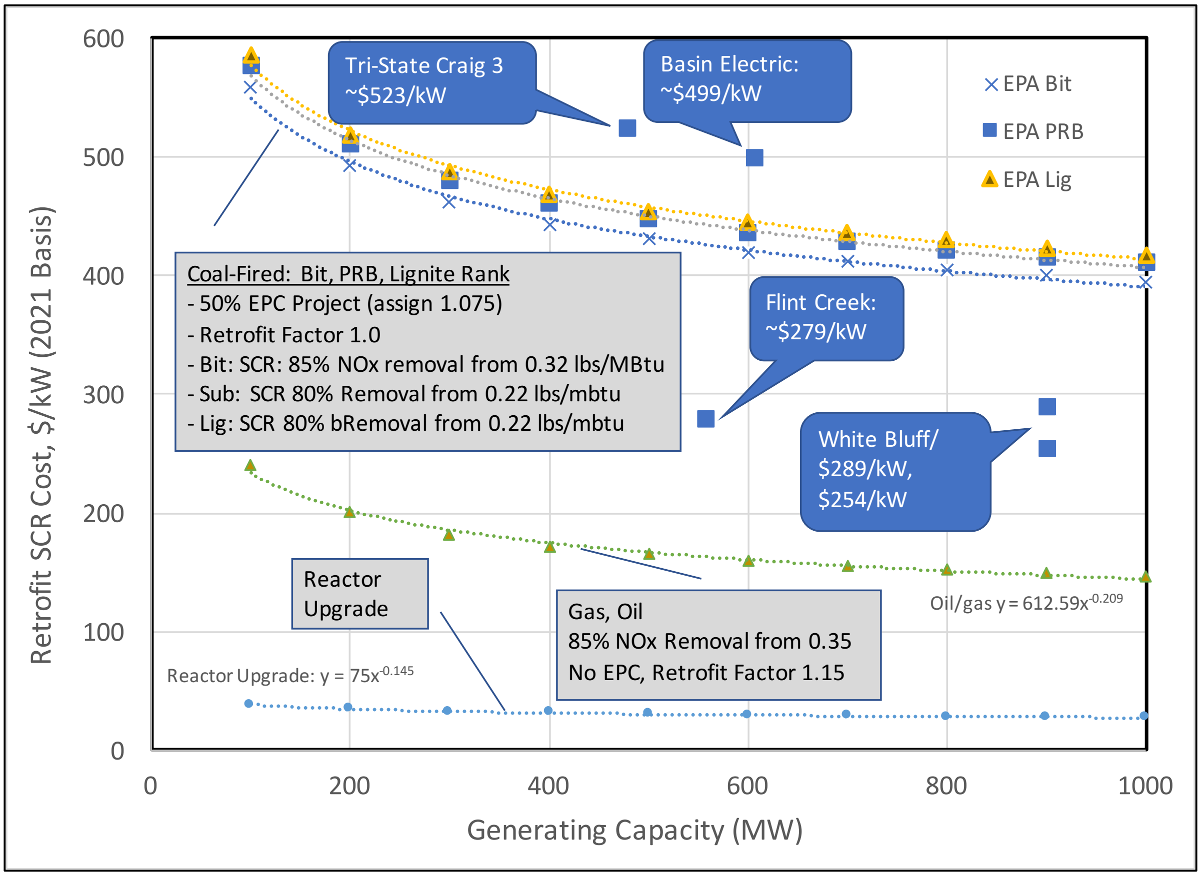

Figure 5-1. Capital Cost vs Capacity Relationship for SCR NOx Control: Coal and Distillate Oil/Natural Gas

Two inputs to the cost correlation – and an adjustment to the escalation methodology – are reflected in the data in Figure 5-1. First, it will be assumed that half of projects will deploy "EPC" (engineer, procure, construct) contracts. S&L assigns a 15% premium cost for such contracting arrangement; consequently a 7.5% premium is elected to account for this action over the unit inventory. A second input is the selection of the Retrofit Factor – which without a specific site to evaluate, is assigned a value of "1".

Third, capital costs are adjusted to reflect recent escalation not captured by EPA. Specifically, S&L escalates costs used in the Retrofit-Cost-Analyzer-Update-1-26-2022" from 2011 to 2021 at an annual rate of 2.5% which does not capture recent trends. For this analysis, the S&L methodology is accepted through 2019 and the Chemical Engineering Process Equipment Index (CEPCI) used to escalate costs from 2019 to a mid-2021 basis. Adopting this latter approach transforms 2011 costs into a mid-2021 basis with a factor of 1.41, compared to 1.28 as utilized by EPA.

For new retrofits, the target NOx emission rate of 0.05 lbs/MBtu represents a significant reduction from the 0.08 lb/MBtu assigned to existing SCR-equipped units. In a separate study for a power station in the Southeast, S&L advised that a design compliance margin of 0.02-0.03

lbs/MBtu be adopted.[25] Further, statistical evaluation of the 17 units described in Section 5.1.1 as meeting the target value of 0.05 lbs/MBtu operate for a significant number of hours at a 0.04 lbs/MBtu average. Consequently, for this analysis the target NOx rate to determine operating costs to achieve an average of 0.05 lbs/MBtu is assumed to be 0.04 lbs/MBtu.

Selecting a NOx operating rate below the 0.05 lbs/MBtu proposed limit – if even feasible – is also justified by the structure of the proposed rule. The target emission rate must provide adequate margin to generate "excess" allowances that can be traded or utilized on units for which SCR retrofit is not feasible.

Figure 5-1 also presents SCR capital cost for units firing oil and natural gas as derived with the *S&L Retrofit-Cost-Analyzer-Update-1-26-2022* file. Analogous to coal-fired evaluation, a cost premium of 7.5% is assigned to address the prospects for half of the inventory employing an EPC contract. A Retrofit Factor of 1 is used. Costs were escalated from 2011 to 2019 the same approach as described for coal-firing.

SCR-Equipped Units. Coal-fired generating units presently equipped with SCR will be assumed to employ enhanced O&M to achieve the ozone season average of 0.08 lbs/MBtu. To achieve an average rate of 0.08 lbs/MBtu over the ozone season an operating rate of 0.075 lbs/MBtu is selected, to provide margin for startup, shutdown, and equipment reliability.

Enhanced O&M practices entailing accelerated catalyst replacement, aggressive catalyst cleaning, and annual tuning reagent injection equipment will be required to achieve the 0.075 lbs/MBtu target rate. Further, early-generation reactors – those in service preceding 2005 - will be assigned a modest capital charge (~$20-25/kW) to update select hardware. The rationale for capital investment is based on the observation that many first-generation reactors (a) are not equipped with state-of-art means to remove accumulated fly ash deposits, or reagent injection hardware, (b) do not optimally distribute incoming flue gas into the SCR reactor, or (c) employ cavities for three (and not four) layers of catalyst, limiting catalyst management actions. Most widespread is the chronic inability to maintain clean catalyst surface, maximizing NOx reduction. Figure 5-2 presents an image of a catalyst layer plagued by ash deposition, as summarized in an owner's catalyst assessment report. Consistently achieving less than 0.08 lbs/MBtu will require equipment upgrades to avoid the catalyst state as depicted. An estimate of the capital required ($/kW basis) is presented in Figure 5-1 as a function of generating capacity.

[25] NOx Control Technology Cost and Performance Study, Entergy Services, Inc. – White Bluff and Lake Catherine. Report SL-011439, Prepared by Sargent & Lundy, May 16, 2013. Note: contained within Response to January 8, 2020 Regional Haze Four-Factor Analysis Information Collection Request, prepared by Trinity Consultants for Energy, April 7, 2020.

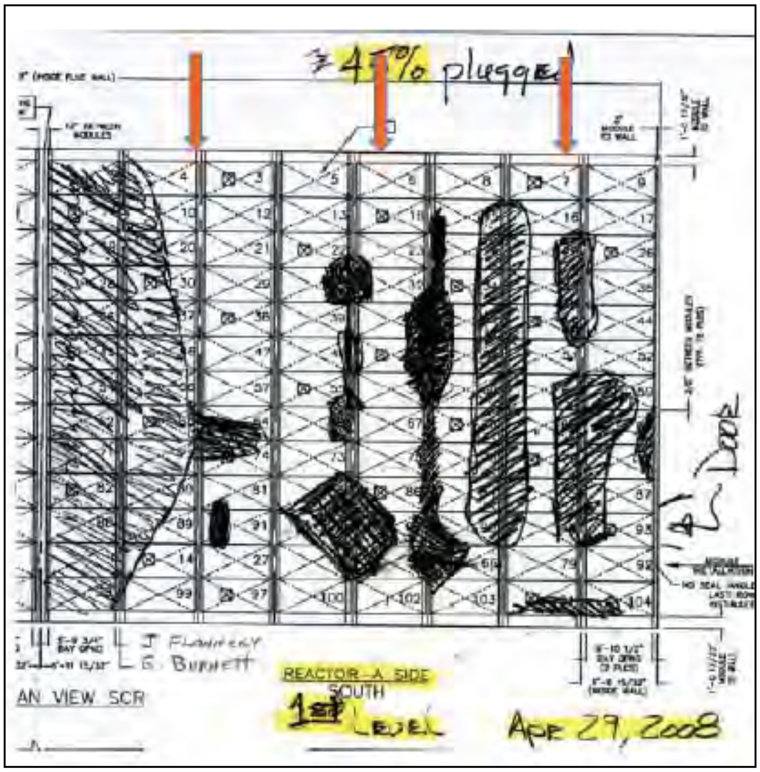

Figure 5-2. Ash Deposition on Catalyst Impeding NO_x Removal Performance

Operating costs are derived from the *S&L Retrofit-Cost-Analyzer-Update-1-26-2022* file. As identified by EPA, not all fixed and variable O&M costs will be assigned to the marginal cost of increasing NOx reduction beyond that incurred in 2021. Fixed O&M and the variable cost for power are invariant with NOx reduction. Reagent use and catalyst replacement do increase with NOx reduction. As with the case for new retrofit installation, the variable O&M for catalyst will be increased by approximately 9% for applications requiring more than 80% NOx reduction.

5.2 Selective Non-Catalytic Reduction (SNCR)

The EPA proposes SNCR be applied to coal-fired units less than 100 MW in generating capacity, and to oil/gas units greater than 100 MW of capacity that emit more than 150 tons of NOx annually.

5.2.1 Performance Basis

EPA states SNCR control capability ranges from 20-40%, depending on the application. Similar to SCR, extracting lower NOx emissions is achieved in exchange for introducing residual NH3 into the gas stream. Unlike SCR, the level of residual ammonia is typically higher than observed with SCR. As noted previously, reagent injected that does not experience the optimal temperature window will oxidize to NOx.

The ability of SNCR to remove NOx generally decreases with lower boiler NOx content, and limits on physical conditions that limit the space between various rows of injection lances.

Further, boiler generating capacity also determines the distance over which urea must be injected and retained in form to release NH3 increases – as does the opportunity to revert to emissions of NH3 or be oxidized to NOx. Consequently, the highest NOx removal allowed for units with (a) boiler NOx emission rates of 0.15 lbs/MBtu or less, and (b) boiler of 200 MW and higher is limited to 30%.[26]

The key technical challenge for SNCR is achieving rapid mixing of urea reagent into a relatively narrow temperature "window", that supports effective reduction of NOx. For most applications, this temperature window ranges from 1,800 – 2,200 F.[27] Unlike SCR, reagent injected for SNCR outside this optimal temperature window generates not only residual NH_3 but is oxidized to NOx – completely counterproductive to the step of NOx control. A key complication is that the physical location of the optimal temperature window – usually near the furnace exit - is not "static" but changes with changes in load. Both enhanced capital investment and a design methodology using computational fluid dynamics (CFD) can increase the opportunity to inject urea into the optimal temperature window. Capital investment enables employing an array of multi-layer injectors to tailor the injection of reagent to follow the temperature window. A thorough design basis employing CFD –requiring exacting details of boiler design – can identify the location of the temperature window and predict movement with load. Both the investment required and time for design and installation are affected.

The effectiveness of SNCR is compromised significantly with low NOx concentration. Specifically, EPRI reports[28] that results from numerous SNCR demonstrations that NOx control capability is limited for NOx concentrations approximating 100 ppm (@ 3% O2) or less (equivalent to approximately 0.15 lbs/MBtu).

5.2.2 Cost Basis

Figure 5-3 presents capital cost for SNCR for coal-fired and oil/gas application, as derived from the S&L reports. Similar to SCR, 50% of the projects are expected to employ an EPC contract, this a premium of 7.5% of capital is assigned. The Retrofit Factor is assumed to be 1. Capital cost is escalated to a 2021-year basis using the CEPCI for the 2019 and 2020, as applied for coal-fired applications.

Ideally, the capital relationships would reflect units where multi-later injection lances are required to assure reagent injection within the correct temperature window. Ample time for engineering analysis to include detailed CFD evaluation would be accommodated in both schedule and engineering costs. Given the role of SNCR on outcome of the 25-state region, the EPA assumptions as stated in IPM background documentation is adopted, solely for the purpose for the present calculations.

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[26] Low Baseline NOx Selective Non-Catalytic Reduction Demonstration, Joppa Unit 3, EPRI Project 1018665, Final Report March 2009. See page 1-1.

[27] Ibid.

[28] Ibid.

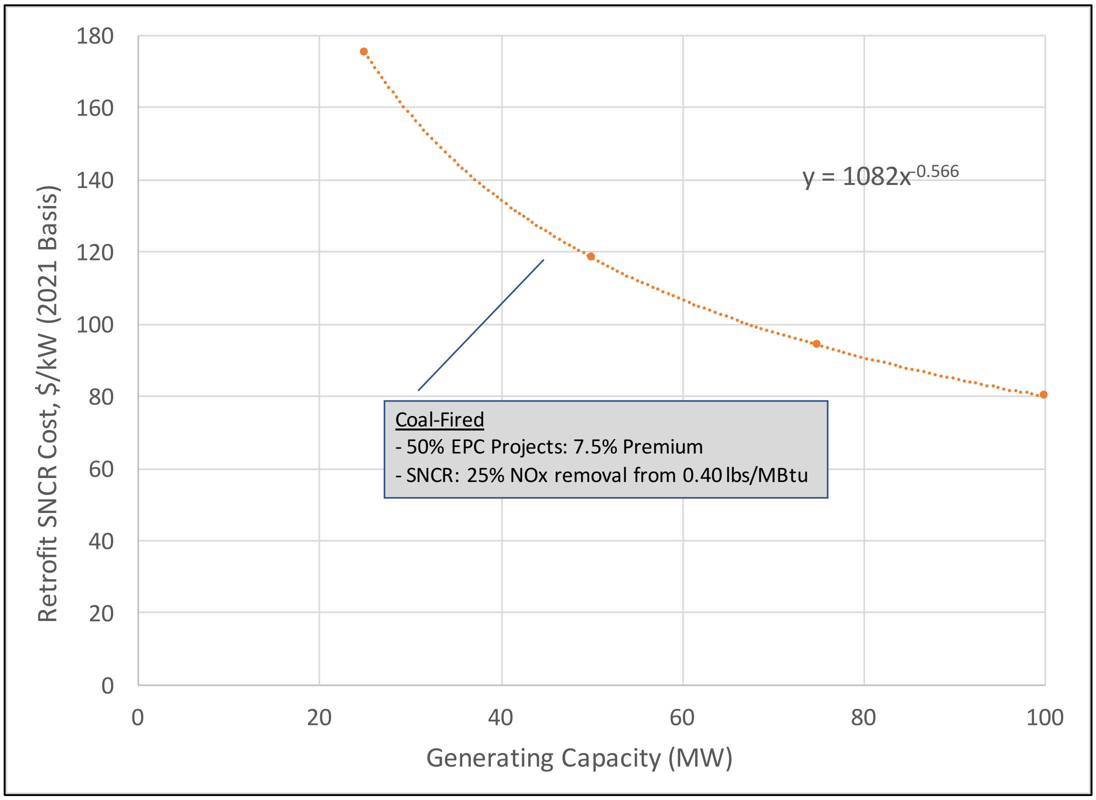

Figure 5-3. Capital Cost vs Capacity Relationship for SNCR NOx Control: Coal and Distillate Oil/Natural Gas

SNCR cost is driven by the delivered price and utilization of reagent for NOx control. In contrast to SCR, where generous time and space for reagent mixing enable almost complete utilization (with minimum loss to molecular N_2 or residual NH_3), for SNCR reagent utilization typically less than 80%.

Operating costs are mostly driven by reagent utilization. These values will vary widely with boiler size, specifics of the furnace outlet and entry to the convective section. Given the role of SNCR on outcome of the 25-state region, the EPA assumptions as stated in IPM background documentation is adopted, solely for the purpose for the present calculations.

5.3 Installation Schedule

Figure 5-4 presents installation schedule information for 18 SCR installations, as managed by ten owners. These data capture all project aspects from planning, conceptual engineering, RFP development, proposal solicitation and review, contract award and negotiation, hardware fabrication and installation. Figure 5-3 shows the typical time required for a single SCR reactor is 40 months, while retrofit of multiple reactors to one site requires 45 months. These authentic, recorded schedules suggest that retrofit of the inventory of approximately 100 units with SCR technology is not feasible.

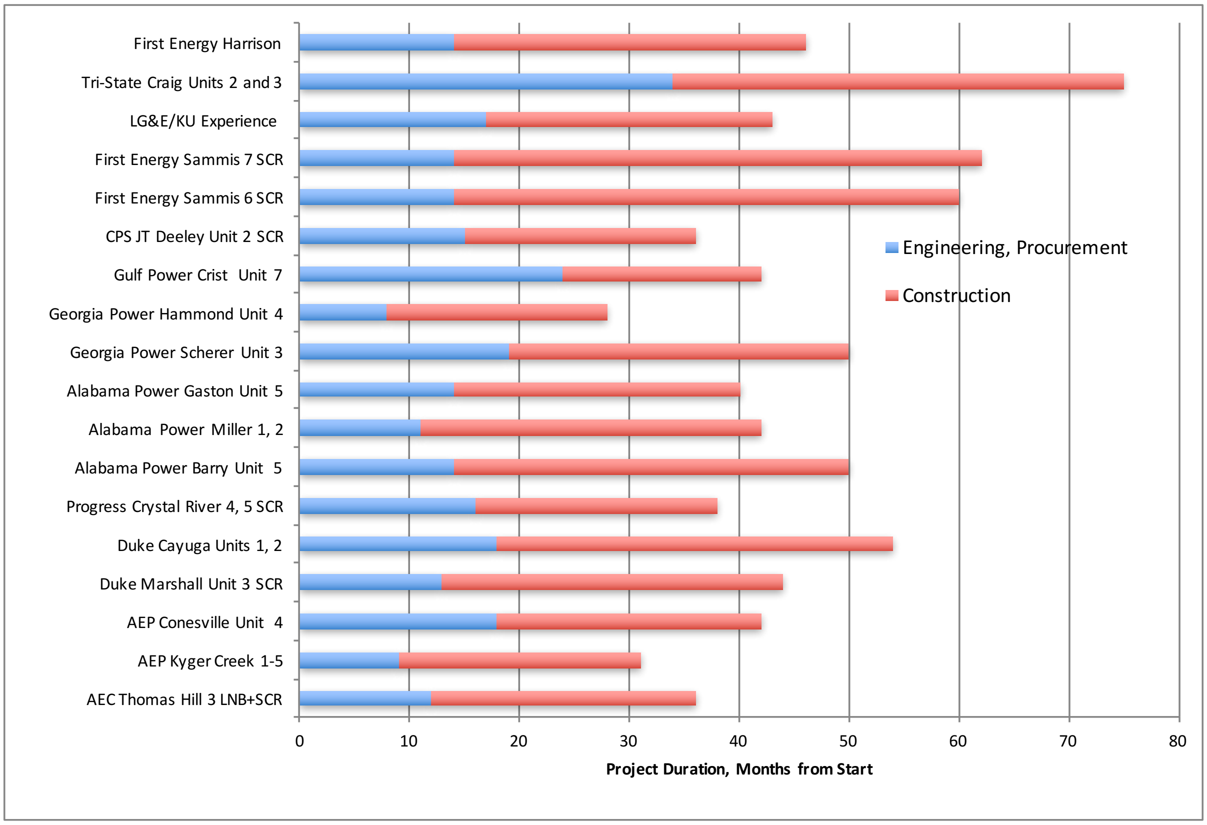

Figure 5-4. Timeline for Engineering, Procurement, and Installation of SCR Postcombustion Control Technology

Even if the installation timeline could be accelerated, there are simply inadequate resources to deploy SCR to the extent required to meet the proposed rule. Figure 5-5 shows the projected increase in SCR inventory compared to historical work, showing that if all installations entered serve in 2026, the magnitude of installations would exceed that of 2003. The inventory could be staged over several years – as Figure 5-5 shows the SCR inventory required for 2005 was installed over 4 years.

Public power and rural electric co-operative utilities face additional challenges with an abbreviated installation timeline, due to the additional step of approval for and raising capital. Three years to install an SCR for municipal utilities is not adequate. EPA should allow for an extension of compliance deadlines, similar to that afforded for non-EGUs.[29] Further, EPA's assumption that owners typically plan a 5-week outage every year – adequate to retrofit SCR – is erroneous. To the contrary, some municipal utilities plan outages of such durations at multiple years.

Finally, a further complication is that owners – to abide by their respective fiduciary responsibilities - cannot initiate major engineering or actions that require significant capital expenditure without a final rule.

[29] See 85 Fr 20104.

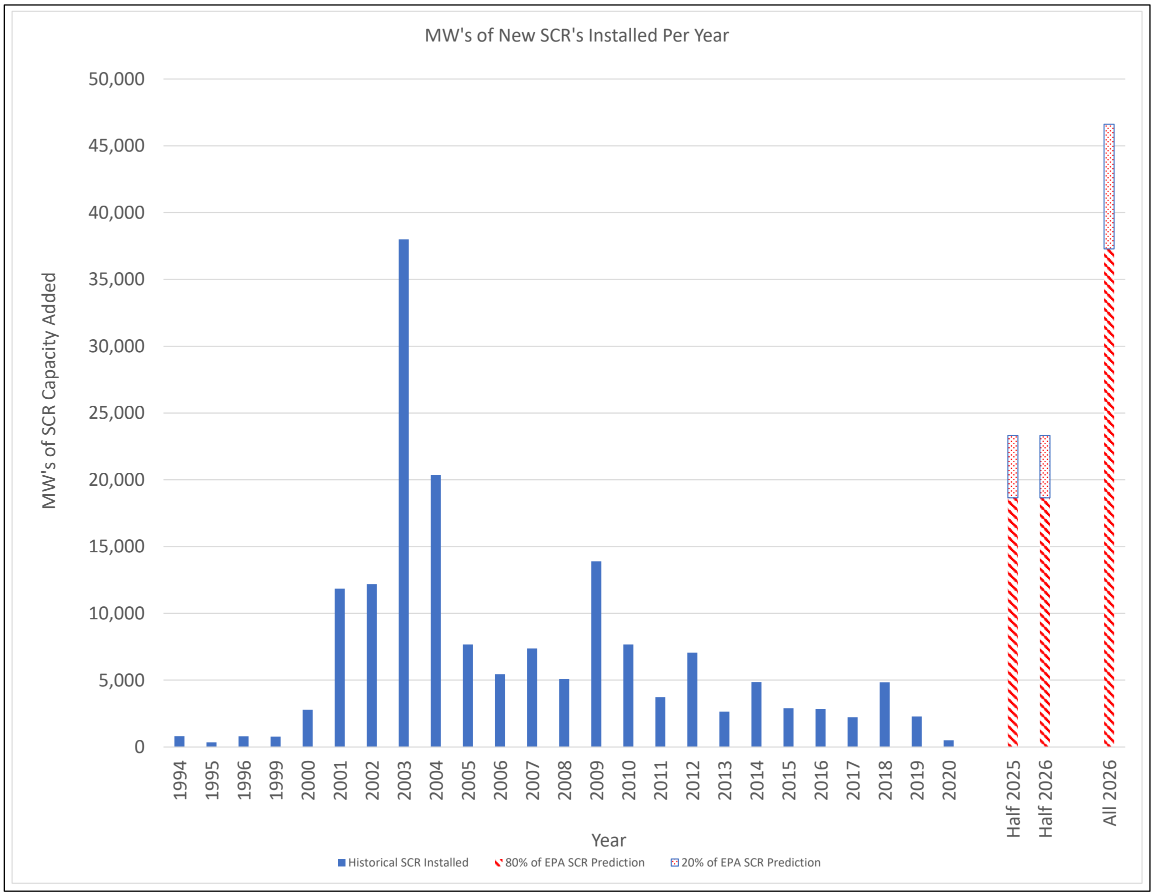

Figure 5-5. Capacity (MW Basis) of SCR Retrofits Since 1994

The requirement to retrofit numerous SCR installations within in a short time period will exacerbate the present imbalance in laborer or contractor shortage, causing delays in SCR installation schedules. Specifically, on rural co-operative owner received a construction estimate showing a 75-month timeline for SCR installation. This estimate significantly exceeds the average noted of 44 months – and means to accommodate these longer timelines should be offered.

6. Cost Evaluation Results: NOx Control Cost per Ton for Ozone Mitigation

Section 6 presents results of the evaluation of incurred cost per ton for NOx removal for several categories of units and operating scenarios. These results are based on the input cost data and assumptions described in Sections 4 and 5.

NOx removal cost is described for coal-fired units (a) with existing SCR, reporting the incremental cost to remove NOx from the 2021 emission rate, (b) equipped at present with exclusively combustion controls, reporting removal cost via retrofit SCR from the boiler NOx exit rates, and (c) less than 100 MW, applying SNCR (for 25% removal). Also reported is the removal cost via SCR retrofit to units firing distillate oil/natural gas units, greater than 100 MW, and that emitted more than 150 tons of NOx per year. The cost per ton is determined for remaining plant lifetime of 10 and 5 years, and for capacity factor (a) adopted by EPA as the reference for this analysis (56% and 26% for coal- and distillate oil/gas-fired, respectively), and (b) at each units' 2021 capacity factor.

6.1 Units without SCR: Retrofit

6.1.1 Coal-Fired Duty

Figures 6-1 summarizes results derived in this study for the 143 units in the 25 states to which SCR is proposed to be retrofit, based on a EPA's assumed capital recovery factor of 0.143 and attendant presumption of a 10-year lifetime.[30] Also shown on Figure 6-1 is the cost per ton reported by EPA for their findings on the 35 states, using their assumed input conditions. The latter EPA-derived data is shown for units in the boiler population at the 50% (median) and 90% values. Figure 6-2 presents analogous results calculated for a 5-year remaining lifetime.

Figure 6-1 shows the median cost incurred for a unit to retrofit SCR where none had previously existed to be $20,250 per ton for operation at 56% capacity factor, while 90% of units in the population will incur a cost not more than $28,103 per ton. The analysis was also conducted for each generating unit using their unique 2021 capacity factor, with results showing the median cost for the population to be $24,340 per ton, while 90% of units in the population will incur a cost not more than $50,000 per ton.

[30] EPA does not define a remaining unit lifetime, but rather states the capital recovery factor used for calculations with both the IPM and Retrofit Cost Evaluation Analyzer. The reported capital recovery factor is 0.143, which comports to the recovery of principle and simple interest using a 10-year remaining lifetime and EPA's historical 7% interest rate. This relationship accounts for return of capital only, excludes associated costs for property taxes and insurance, and assumes instant or "overnight" construction. The relationship is defined as follows: Capital Recovery Factor = [i(1+i)n]/[(1+i)n−1], where "i" is interest rate and "n" is years for recovery. For comparison, the same cost basis is calculated for a 5-year remaining lifetime, which may reflect the plans of several operators.

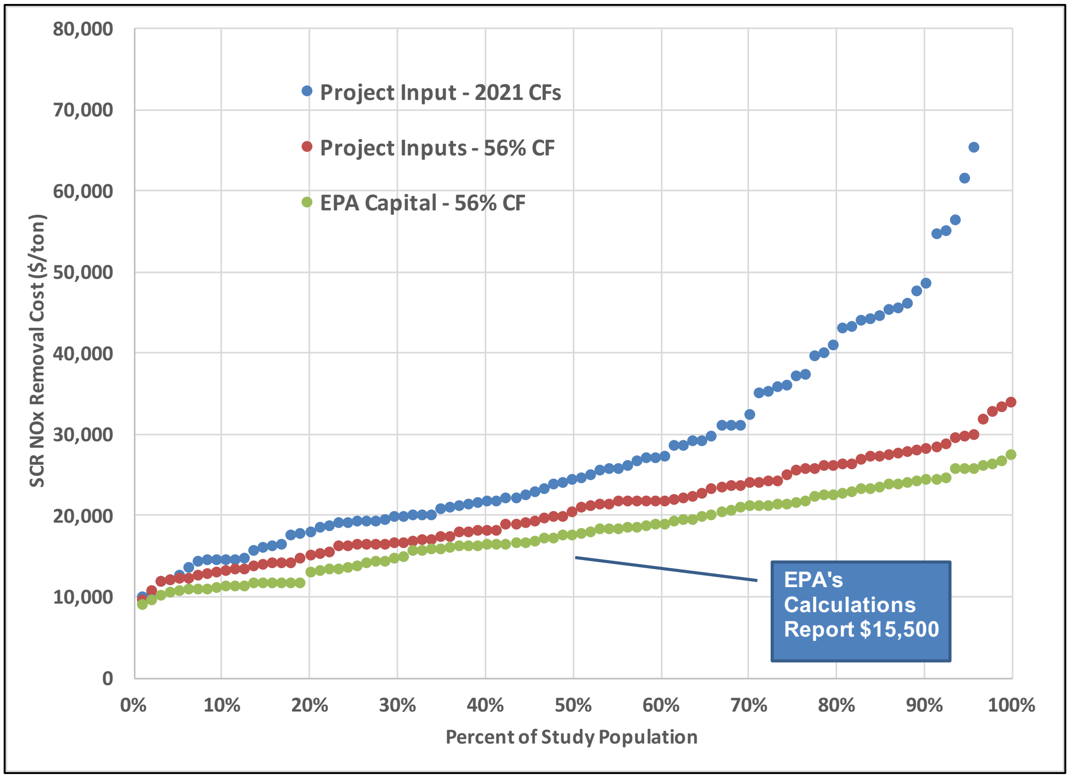

Figure 6-1. SCR Retrofit to Coal-Fired Units: Incurred Cost per Ton, 10-Year Basis

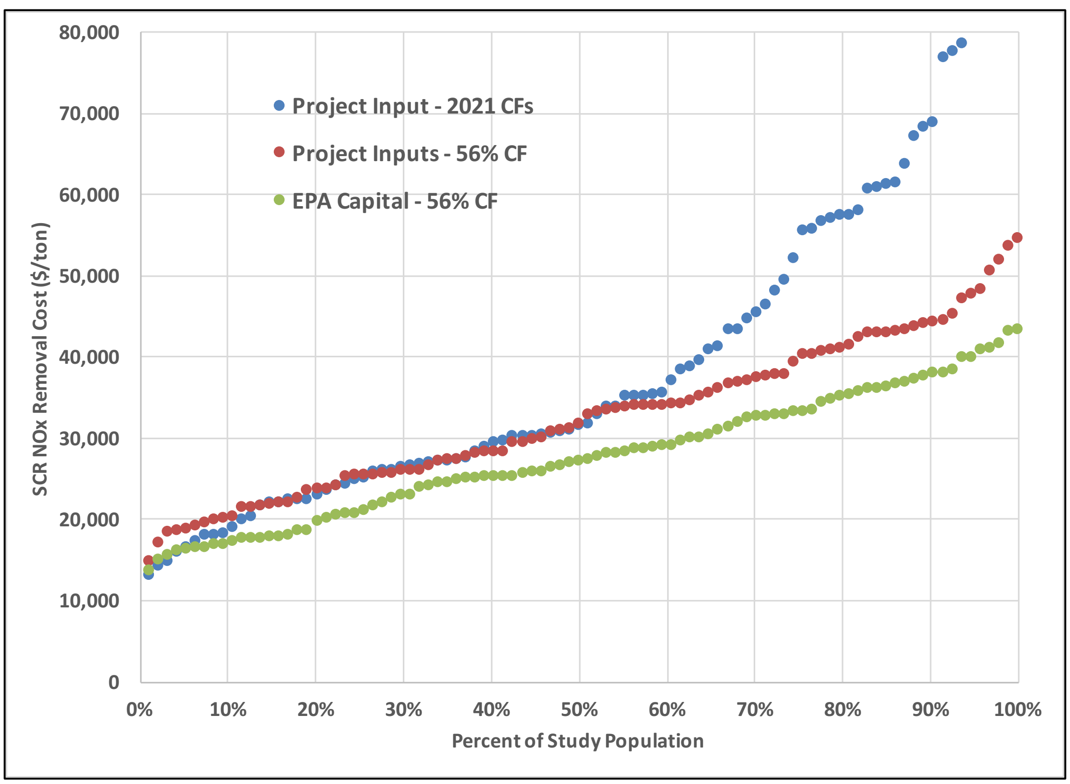

Figure 6-2. SCR Retrofit to Coal-Fired Units: Incurred Cost per Ton, 5-Year Basis

Figure 6-2 shows the decrease in lifetime from 10 to 5 years significantly increases cost. The incurred cost for a unit at the median population is projected to be $31,663 per ton for operation at 56% capacity factor, escalating to approximately $44,286 per ton for a unit at the 90% population. For operation at the 2021 capacity factor, the analysis shows the cost for the median population to be nearly identical at $32,286 per ton, while 90% of units in the population will incur a cost not more than approximately $70,000 per ton. The 5-year lifetime approximately doubles incurred costs.

As described in Section 5, we could not replicate EPA's results. The bulk of the disagreement is likely due to the different database of units, as the additional states included in EPA's analysis incur a 11% lower control cost. A second contributing factor could be the specific mathematical relationship used in SCR capital cost accounting - two were referenced in the TSD.[31] Additional transparency in how EPA derived these costs is required, and requested from the EPA. Using the Retrofit Cost Analyzer as the calculation method as described in the TSD with EPA's inputs, but confining the analysis to the 25 states, the projected cost at the median population is $17,508/ton NOx reduced, exceeding EPA's reference case value of $15,500/ton.

Two factors drive the cost per ton of NOx removed for results in Figures 6-1 and 6-2 – the capital required and the boiler NOx exit rate, the latter determining the NOx tons removed over which amortized capital and operating costs are distributed. Notably, generating units with low boiler NOx emission rates – particularly 0.15 lbs/MBtu or less – incur extremely high costs for NOx control with SCR. Figure 6-3 depicts data from Figure 6-1 as a function of boiler NOx exit rate – showing how cost ranges from $25,000 to $35,000 per ton. This cohort of units incurs significant cost penalties to deploy SCR to meet the EPA proposed rule.

6.1.2 Distillate Oil/Natural Gas

SCR retrofit is proposed for oil/gas-fired units 100 MW or greater capacity and that generate more than 150 tons of NOx annually.

Figure 6-4 summarizes results derived in this study for the 35 units in the 25 states which qualified by EPA's criteria to retrofit SCR, based on a 10-year remaining lifetime. Also shown on Figure 6-4 is the cost per ton reported by EPA for their findings on the 35 states, using their assumed input conditions.

Results from this study report the incurred cost for a unit at the median population of $11,373 per ton for operation at 26% capacity factor, escalating to approximately $19,000 per ton for units at the 90% population. For operation at the 2021 capacity factor, the analysis shows the cost for the median population to be $37,754 per ton, escalating to more than $80,000 per ton.

[31] EPA is not clear as to whether the SCR Retrofit Cost Analyzer is used, or the relationship described for IPM (Table 5-5 of Chapter 5 Emission Control Technologies.) The difference in these two mathematical relationships -- upon converting to a 2021-dollar basis using EPA's cost adjustment – is an additional 4%.

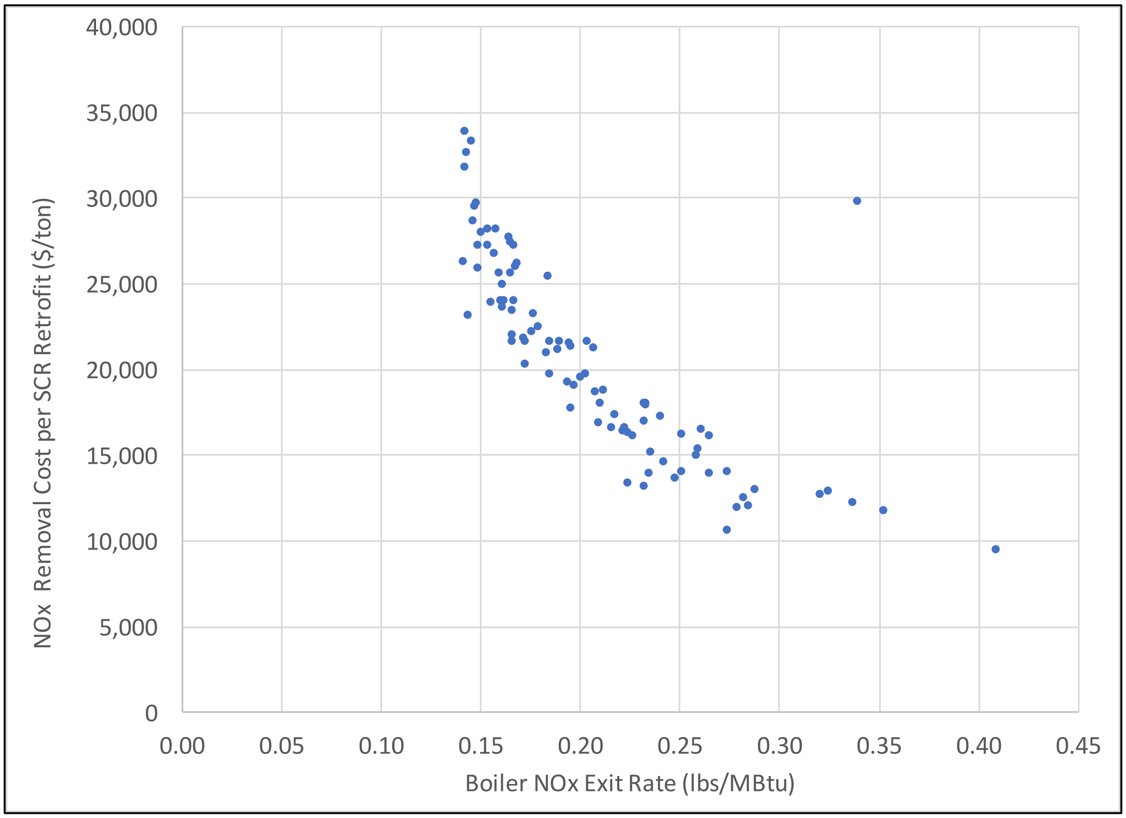

Figure 6-3. NOx Removal cost per SCR Retrofit: Role of Boiler Exit NOx Rate

Efforts to replicate EPA's calculation were reasonably successful, as among other factors, EPA's boiler inventory varied little from that used in this study. The cost at the median estimated by this study using EPA's relationships is $10,426, approximating EPA's published reference.

Figure 6-5 presents results for a 5-year remaining lifetime. Figure 6-4 reports a significant increase in costs. The incurred cost for a unit at the median population is projected to be $18,429 per ton for operation at 56% capacity factor, escalating to approximately $32,000 per ton for a unit at the 90% population. For operation at the 2021 capacity factor, the analysis shows the cost for the median population to be $62,661 per ton, escalating to more than $80,000 per ton for a unit at the 90% population. The 5-year lifetime increases costs by approximately 30%.

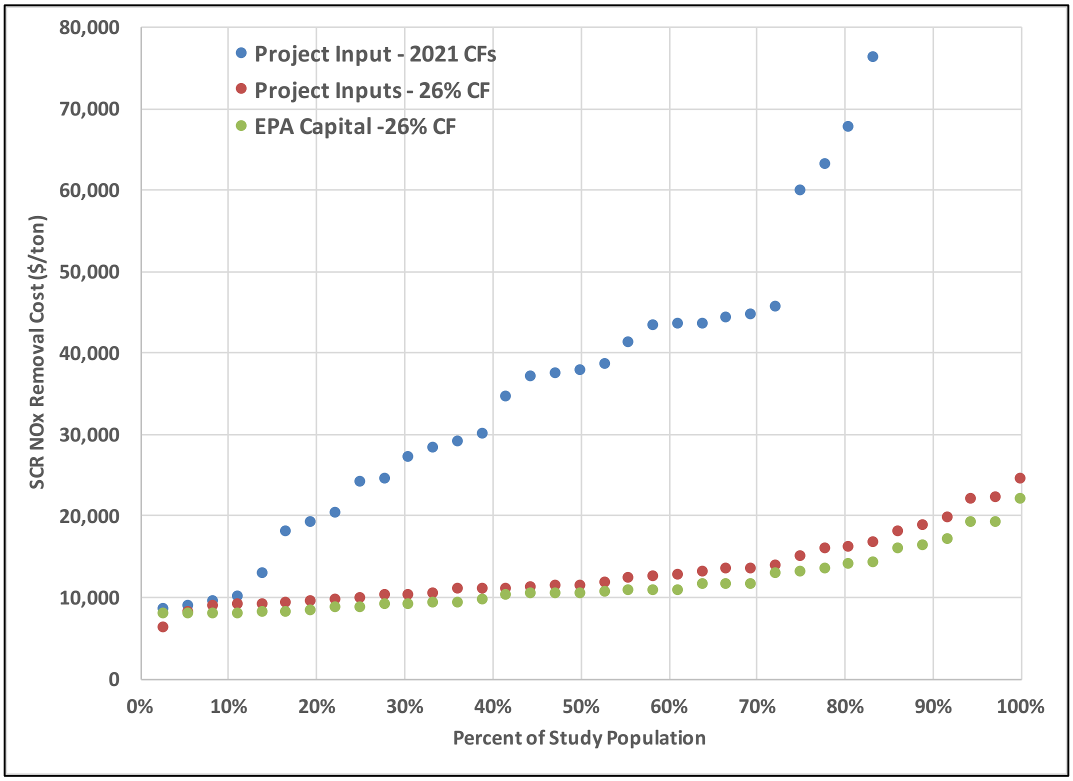

Figure 6-4. SCR Retrofit to Oil/Gas-Fired Units: Incurred Cost per Ton, 10-Year Basis

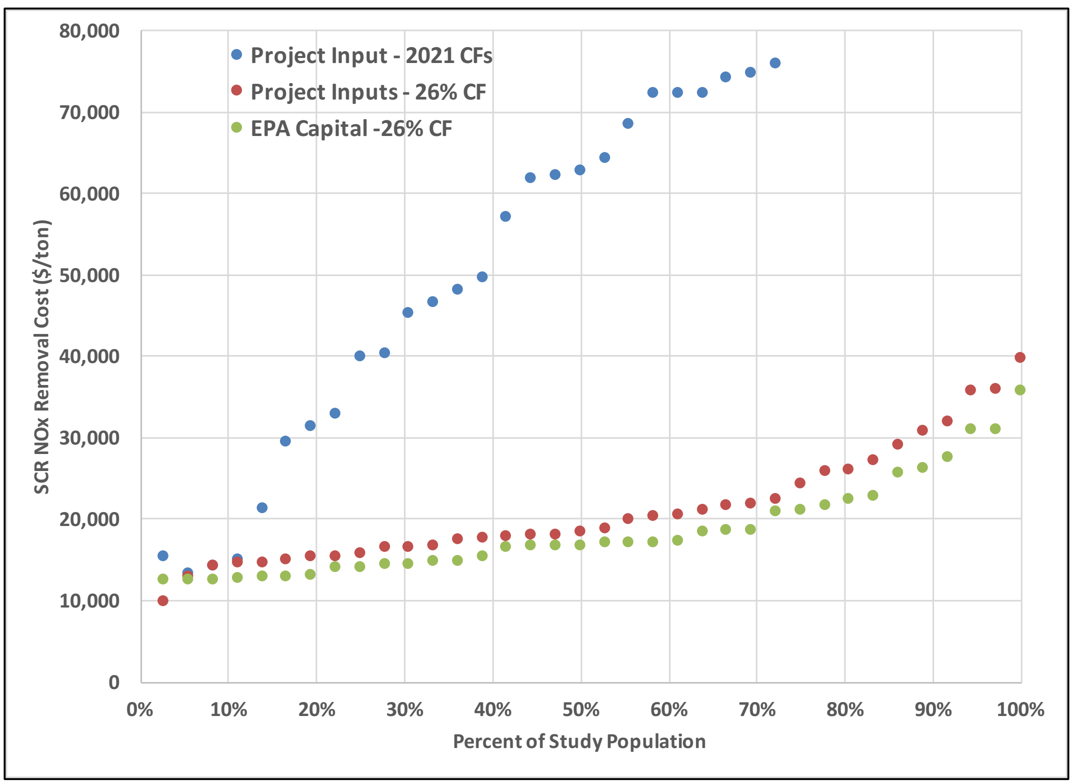

Figure 6-5. SCR Retrofit to Oil/Gas-Fired Units: Incurred Cost per Ton, 5-Year Basis

6.2 SNCR Retrofit

SNCR retrofit is proposed for both coal-fired units of capacity of 100 MW or less.

Figure 6-5 summarizes results derived in this study for the eight units in the 25 states to which SNCR is proposed for retrofit, based on a 10-year remaining lifetime. This analysis employs the same calculation methodology used by EPA (the S&L Retrofit Cost analyzer) with the exception that costs are escalated to 2021 using the CEPCI.

Results from this study report the incurred cost for a unit at the median population of $12,645 per ton, for operation at 26% capacity factor as proposed by EPA,[32] escalating to more than $100,000 per ton for a unit at the 90% population. For operation at the 2021 capacity factor, the analysis shows the cost for the median population to be $67,432 per ton. For these same input conditions and similar unit inventory, EPA reports incurred cost per ton for the median unit as $7,100/ton.

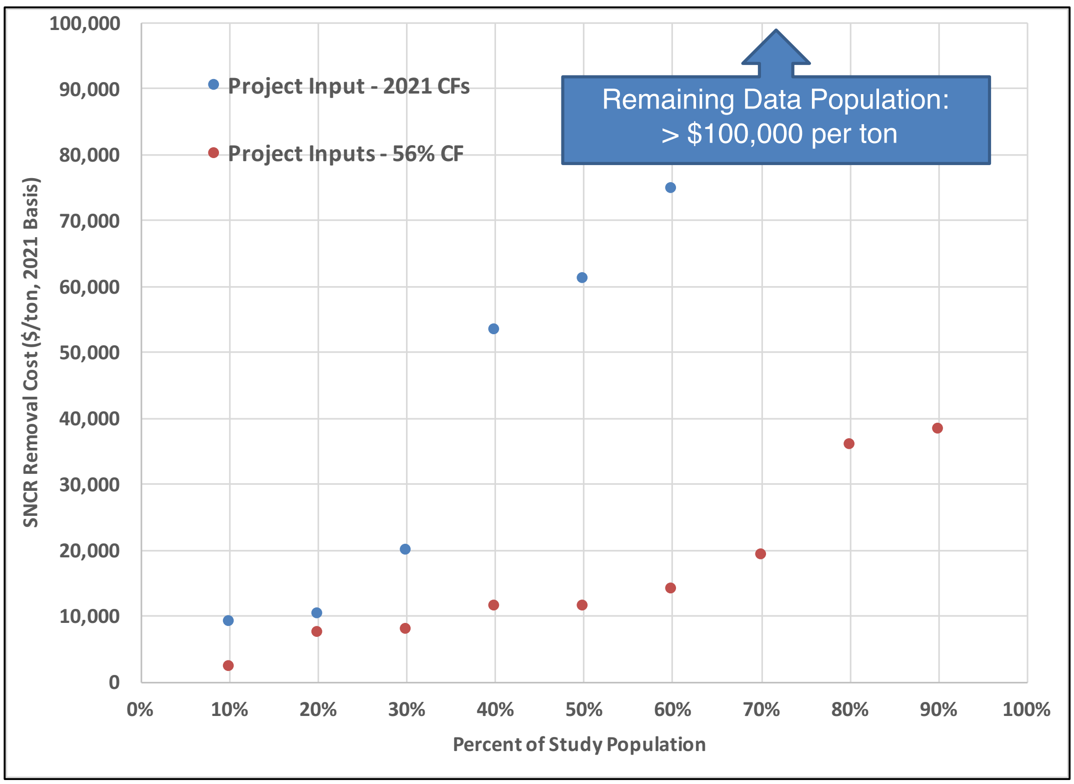

Figure 6-6. SNCR Retrofit to Coal-Fired Units: Incurred Cost per Ton, 10-Year Basis

Results for a 5-year remaining lifetime (not shown) report incurred costs that escalate by approximately 50%. The incurred cost for a unit at the median population is projected to be $19,438 per ton for operation at 56% capacity factor, escalating to more than $100,000 per ton for a unit at the 90% population. For operation at the 2021 capacity factor, the analysis shows the cost for both the median and 90% population exceed $100,000 per ton.

[32] EGU_TSD. Page 23.

6.3 Existing SCR Performance

The NOx removal costs incurred by enhancing the performance of existing SCR process equipment ae presented in this section. These costs are determined using the methodology described in Section 4, and reflect changes to EPA mathematical relationship address elevated catalyst management costs for NOx removal exceeding 80%, capital to refurbish SCR reactors entering service prior to 2005, and employ the CEPCI to escalate costs (from 2019) to mid-2021.

Figure 6-6 presents results for the study population of 94 units from the 25 states. Data are shown for a 5 and 10-year recovery period for the nominal investment (approximating $25/kW) for units that entered commercial duty prior to 2005. These results show the median cost is approximately $14,000-$15,000 per ton; 90% of units in the population will incur a cost not more than approximately $40,000 per ton.

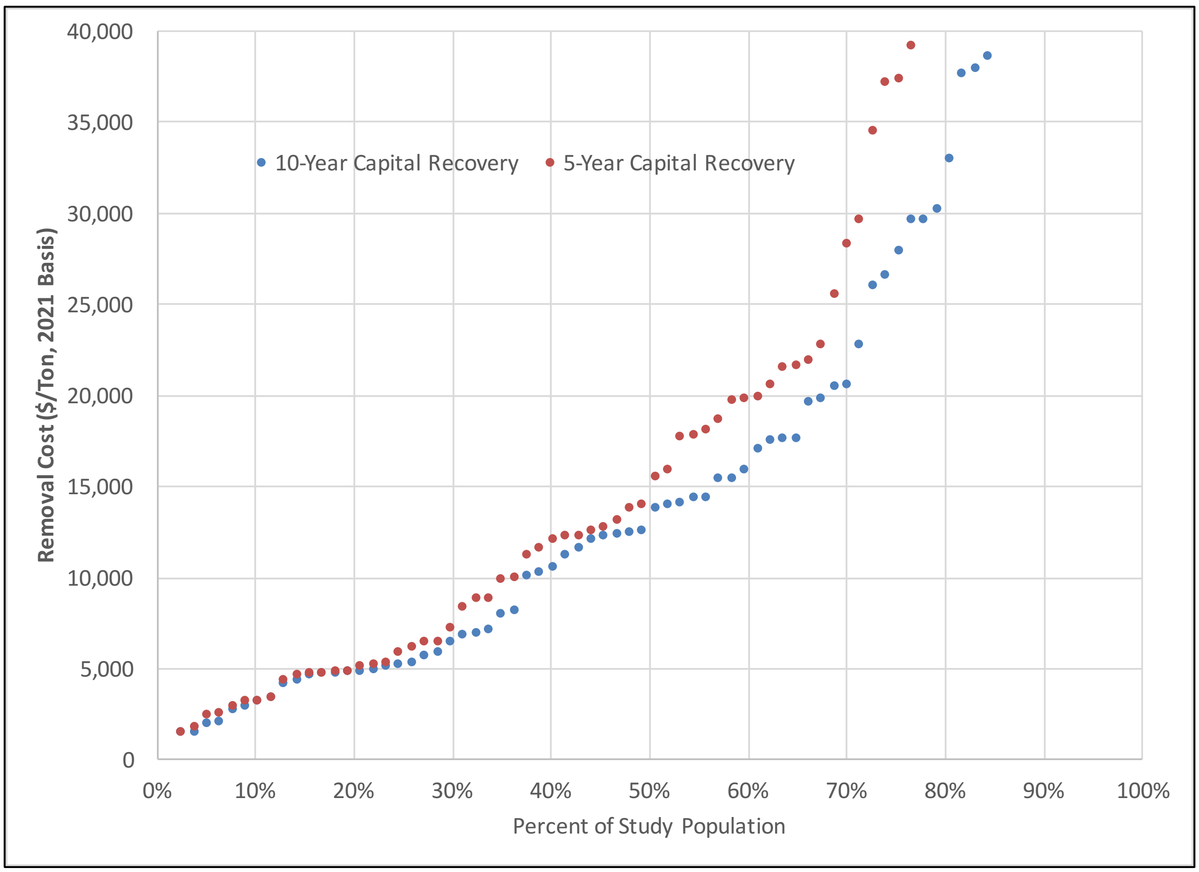

Figure 6-7 Incurred Cost per Existing SCR to Achieve 0.08 lbs/MBtu

Figure 6-7 presents the true cost EPA should be using as the metric - the marginal cost for the incremental reduction in NOx from the 2021 ozone season rate achieved by SCR. Absent EPA actions, this 2021 NOx rate would continue – thus enhancing SCR performance to meet 0.08 lbs/MBtu (with margin) is an additional benefit. The methodology to determine this cost is the proper approach to value the cost of this aspect of the proposed rule.

EPA does not address the true marginal cost. Rather, EPA focuses on estimating the cost for "re-starting" an "idled unit – an event rarely if ever encountered in practice.[33] EPA's analysis employs equations defined in the Retrofit Cost Analyzer to evaluate hypothetical "typical" units, selecting a range of inlet NOx, percent NOx removal, and capacity factor to bound the results. The highest cost projected by EPA using this method is $2,220 /ton.

6.4 Postcombustion NOx Takeaway

The retrofit of SCR to coal units, if feasible given the schedule constrain, will reduce NOx for a cost of $20,250 per ton at 56% capacity factor, escalating to approximately $28,000 per ton for units at the 90% population. These costs increase if estimated using each units' unique 2021 ozone season capacity factor, or a 5-year recovery period. Almost 100 units (94 evaluated in this study versus 88 evaluated by EPA) units will be required to retrofit SCR. The costs predicted by this study - $20,250/ton at 56% capacity factor for the median unit in the population – exceed EPA's estimate of $15,500/ton by approximately 33%.

Generating units with boiler exit NOx rates of 0.15 lbs/MBtu, if retrofitting SCR, will incur NOx removal cost <u>on a per ton basis that are exorbitant</u>. This study showed generating units in the 25-state region with boiler NOx rates approximating 0.15 lbs/MBtu incurred NOx removal costs of $25,000 to $35,000 per ton, based on a 56% capacity factor.

The retrofit of SCR to distillate oil/gas-fired units to 35 "qualifying" units incurs cost for a median unit from $11,000/ton at 56% capacity factor and 10 year remaining life, to over $66,000/ton for operation at the 2021 capacity factor and 5 year remaining lifetime.

Increasing NOx removal from existing SCR process equipment – and considering the marginal cost of this action – incurs a median cost of approximately $15,000/ton, escalating to more than $40,000/ton for a unit at the 90% population. EPA does not calculate the marginal cost for this action, but rather a cost for "restarting idled units", which in their evaluation does not exceed $2,220/ton.

SNCR retrofit as EPA proposes – to coal-fired units of 100 MW generating capacity or less - captures only six units. The incurred cost for the median unit ranges from $12,645/ton to more than $100,000/ton, the latter elevated reflecting operation at the 2021 capacity factor and 5 year remaining lifetime. These costs well exceed EPA's reference basis for SNCR for the population of boilers less than 100 MW of $10,800/ton for coal application.

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[33] See EGU TSD, page 6.

7. Proposed Backstop Daily NOx Rate

Section 7 address EPA's proposed daily backstop NOx rate of 0.14 lbs/MBtu. The derivation of this rate as described in the EGU TSD does not account for the inherent variability that even well-maintained SCR reactors encounter.

Operating data from the national fleet of units equipped with SCR provides insight to the variability of operation, particularly during the startup /shutdown events that almost without exception a unit encounters during an ozone season. This analysis considers the NOx emission trends of 110 units that during the 2021 ozone season operated SCR reactors at high performance levels, meeting the 0.08 lbs/MBtu seasonal average. These data are insightful in terms of the prospect of occasionally exceeding on a daily basis the proposed backstop rate of 0.14 lbs/MBtu

7.1 Background: Startup

Figure 7-1 presents an example timeline for SCR startup, defining the key events over three categories of time. The timeline shows in the initial time period (0-3 hours) how the induced and forced draft fans initiate operation, when coal is introduced and when the flame is stabilized. During the second time period – ranging from 3 to 24 hours –gas temperature leaving the boiler and thus entering the SCR reactor reaches 300-400 ºF; and thereafter achieves the minimum temperature at which ammonia reagent can be injected. This minimum temperature varies with many factors, most importantly fuel composition and associated sulfur content, and can be approximately 580 ºF for subbituminous coals up to 620 ºF for some bituminous coals. At this juncture ammonia reagent is injected, and postcombustion removal of NOx initiates – limited by the gas temperature and the 'activity' of the catalyst for NOx reduction, as well as limits in mixing. During the third time period – 24+ hours or more – the unit achieves full load and the SCR is able to operate at design values.

Figure 7-1 shows that "Phase 1" of SCR reactor operation initiates when the flue gas minimum operating temperature is attained – at some point within the 3-24 hour period after the coal flame is stabilized. This Phase 1 period persists for 3-6 hours, evolving into Phase 2 as the unit approaches full load – and the reactor gas temperature approaches full load values. The Phase 2 or commercial operating state is attained typically after 6 hours from ammonia in injection.

Figure 7-2 presents a timeline of data observed in May of 2020 from an actual process startup for LG&E/KU Mill Creek Unit 4, a bituminous wall-fired unit. The outage from which Unit 4 is emerging up reflects a typical 'pre-ozone season' outage, essential to inspect catalyst and equipment for reagent injection. The NOx emission rate is recorded through the startup and reflected on the left axis, while the ammonia reagent (gallons/hr), load (MW), and reactor temperature (ºF) are reported on the right axis. Also shown is the daily NOx average, constructed per EPA boiler operating day data.

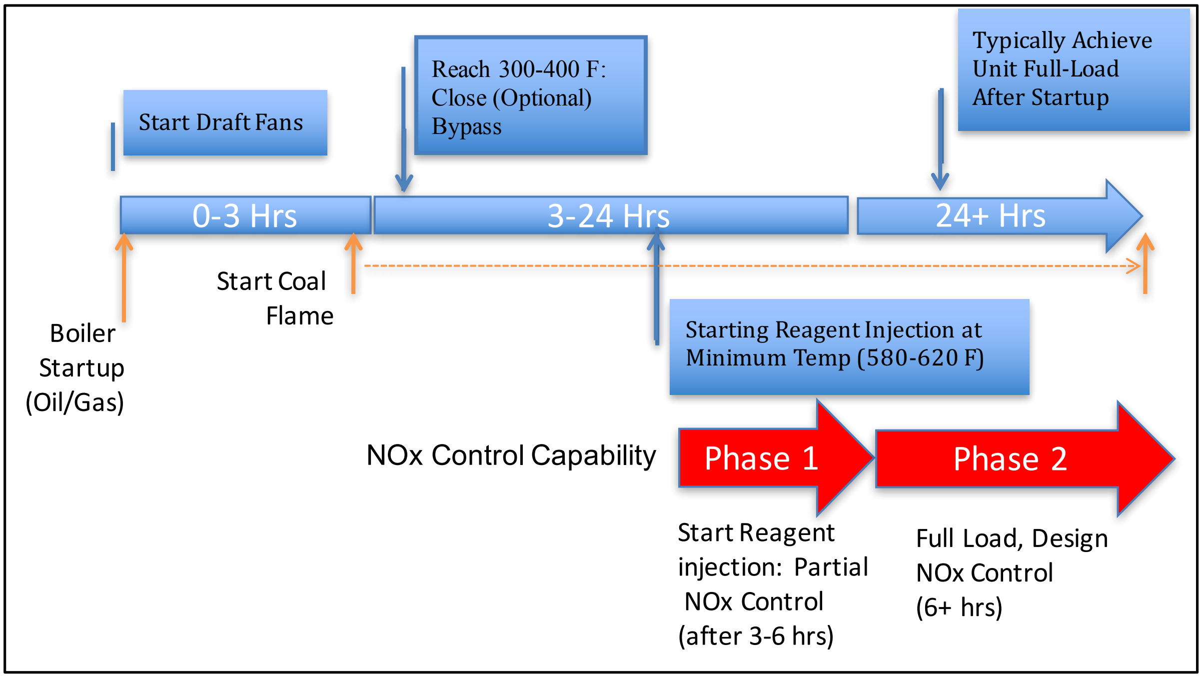

Figure 7-1. Timeline of Key Events in SCR Process Startup

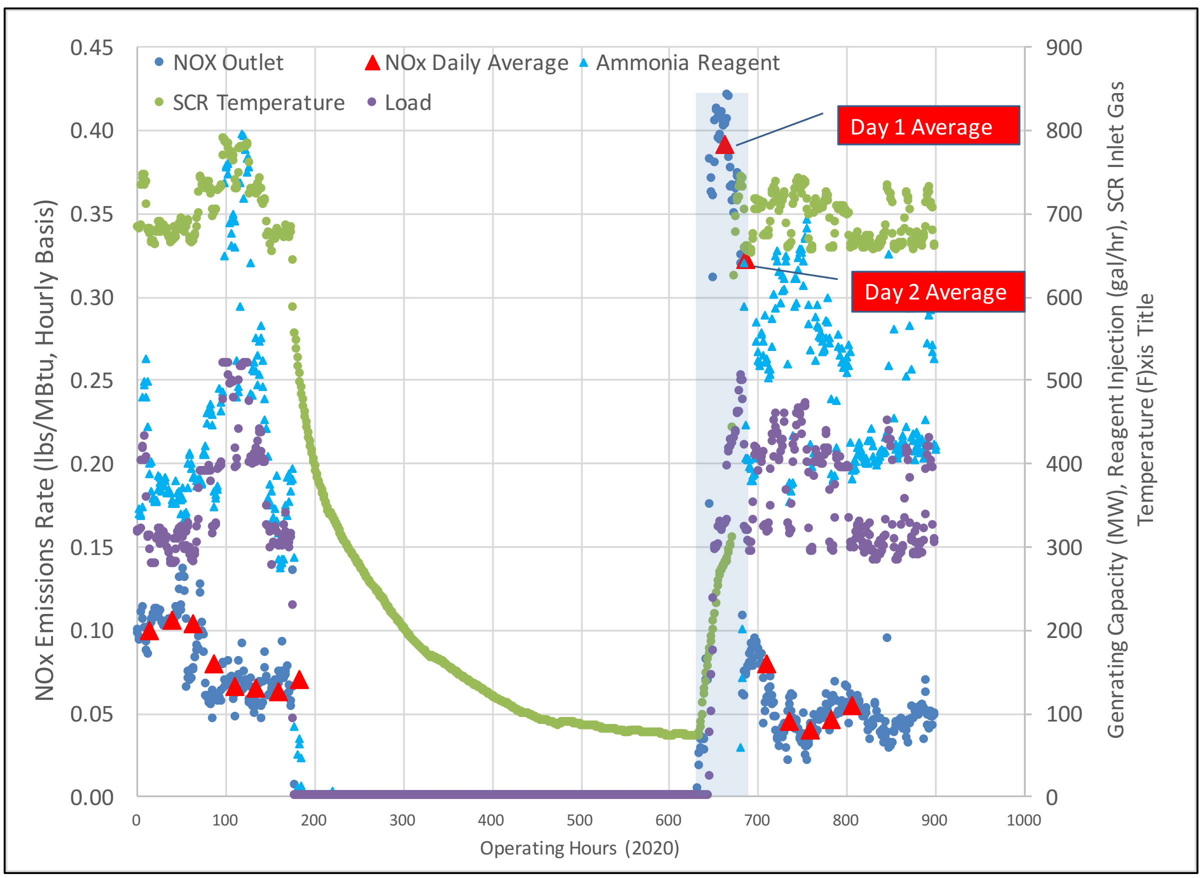

Figure 7-2. LG&E/KU Mill Creek Unit 4 Startup Data

Figure 7-2 shows that at least for two boiler operating days following ammonia injection, the daily NOx rate exceeds the proposed backstop value of 0.14 lbs/MBtu. Consistent with Figure 7-2, EPRI reports typical SCR startup periods are 7-24 hours, and impact the ability of the SCR process to effectively remove NOx.[34]

Additional insight as to the role of startup on delaying operation of SCR and control of NOx emissions is reflected data from six startup events experienced by LG&E/KU Trimble County Unit 2, from January 31 2020 to April 28 2021. Figure 7-3 presents a bar chart summarizing the time required for from establishing combustion to (a) "sync" with the power grid, (b) initiate reagent flow, and (c) to achieve 80% NOx reduction.

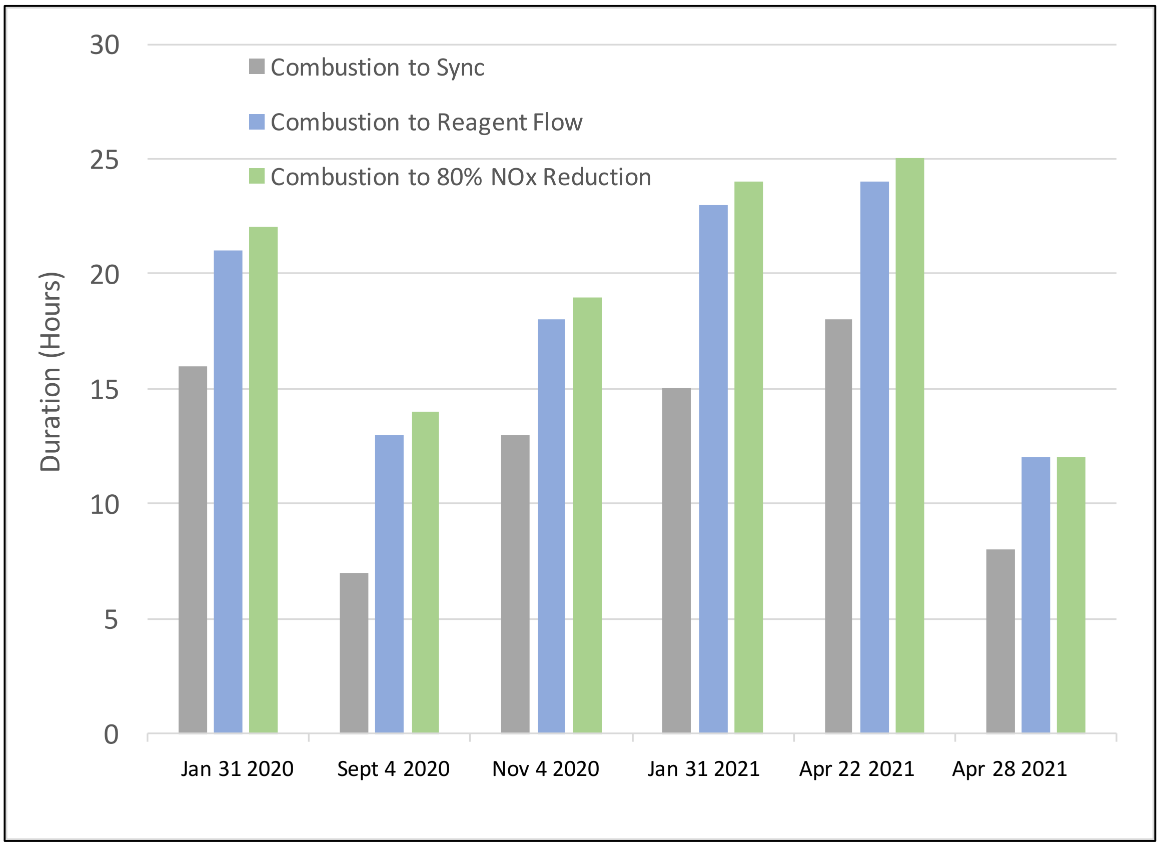

Figure 7-3. LG&E/KU Trimble County 2: Time Duration of SCR Startup Events

The key takeaway from Figure 7-3 is the time required for 80% NOx reduction, which over six startup events ranges from 12 to 25 hours.

Additional experience shared by LG&E/KU with startup of an SCR-equipped unit firing eastern bituminous fuel is insightful. LGE/KU documented elapsed time from firing to ammonia injection of approximately 16 hours for many of their SCR-equipped units, from a cold start <u>under ideal conditions</u> – that is, as long as there were no other equipment failures.[35] In some

[34] EPRI 3002015872 – Operation and Maintenance Guidelines for Selective Catalytic Reduction Systems, December, 2011.

[35] Personal Communication, LG&E and KU Energy LLC Staff: June 15, 2022.

cases, multiple starts are required to address unanticipated issues with ancillary equipment. Some unit startups require longer – a few days – to reach ammonia injection temperatures. Notably, the time to initiate ammonia injection is not up to the discretion of the owner – but specified by the SCR or catalyst supplier.

Although not the focus of this discussion, the "mirror" step of startup - shutdown - can remove SCR from service with the unit continuing to operate for 1-2 hours.

7.2 2021 Inventory Data

NOx emissions from a subset of units operating at high NOx removal over the ozone season illustrate how startup/shutdown events affect emissions. For each of the 110 units in the SCR-equipped inventory which emit less than 0.08 lbs/MBtu for the ozone season, the daily NOx emission rate (per EPA's definition of a boiler operating day) is calculated. As subsequent data shows, even well-performing units experience daily NOx emissions exceeding 0.14 lbs/MBtu. Both the number of units for which a daily rate exceeds 0.14 lbs/MBtu and the number of events were recorded. Results are reported in Figures 7-4 to 7-8.

Count of Units with Daily Emissions Above the Proposed Backstop Rate. Figure 7-4 reports for the 110 units that achieved 80% NOx reduction for the 2021 ozone season, the number of units for which NOx is observed to exceed the proposed daily rate of 0.14 lbs/MBtu. Figure 7-4 shows about 1/3 of the total units in this population – 36 – do not experience excursions in NOx daily rate exceeding the proposed 0.14 lbs/MBtu. The horizontal axis describes the increase in units that emit more than 0.14 lbs/MBtu, for multiple days. For example, eleven units operated above 0.14 lbs/MBtu for three days, while five units exceed that rate for 7 days.

Count of Units with Startup Days. Figure 7-5 reports the number of units that experienced a startup in the 2021 ozone season, ranging from none ("0") to 13 days. Figure 7-5 shows only 6 units did not encounter any startup days. The largest number of units – 21 – encountered three startup days, while three units encountered 10 startup days.

Count of Units per Hours of Outage. Figure 7-6 reports the number of units that experience outages of at least one hour a day – necessitating as a minimum a "hot" startup. Figure 7-6 describes the wide range of outage days incurred by the 110 units that achieved the 2021 ozone season limit of 0.08 lbs/MBtu.

Figure 7-6 shows the median unit encountered 27 days of the 153-day season – almost 20% - affected by an outage (requiring at least one startup and affecting NOx emissions). The units that were least influenced by outages – units at the 10% of the study population – experienced four days affected by an outage. Conversely, units most influenced by outages –units at the 90% percentile - encountered 76 days.

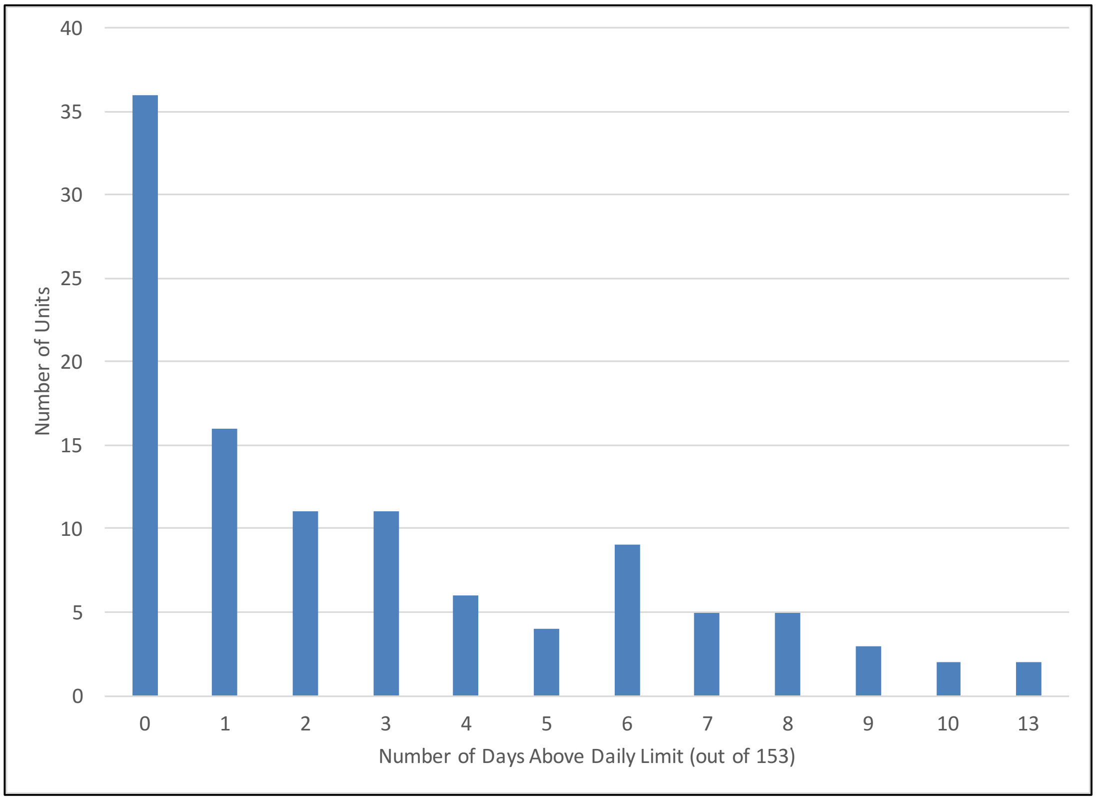

Figure 7-4. Count of Units Emitting Above Proposed Backstop Rate

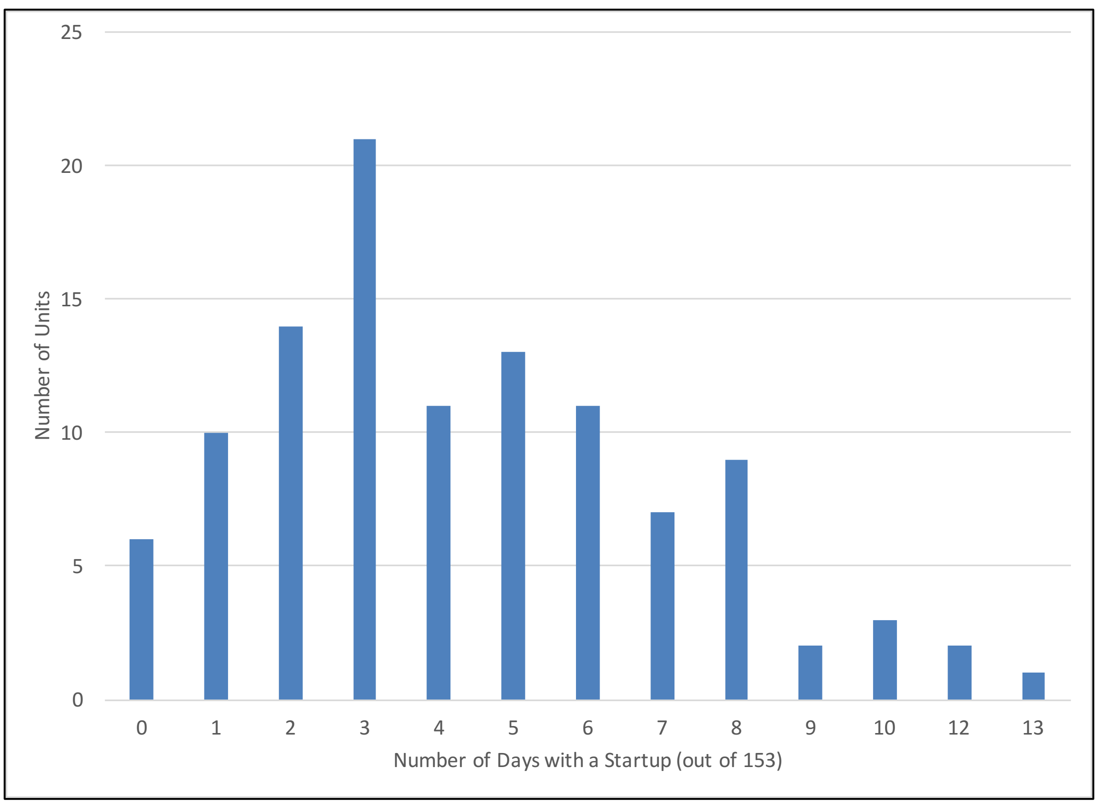

Figure 7-5. Role of Startup days on Count of Units Emitting Above Proposed Backstop Rate

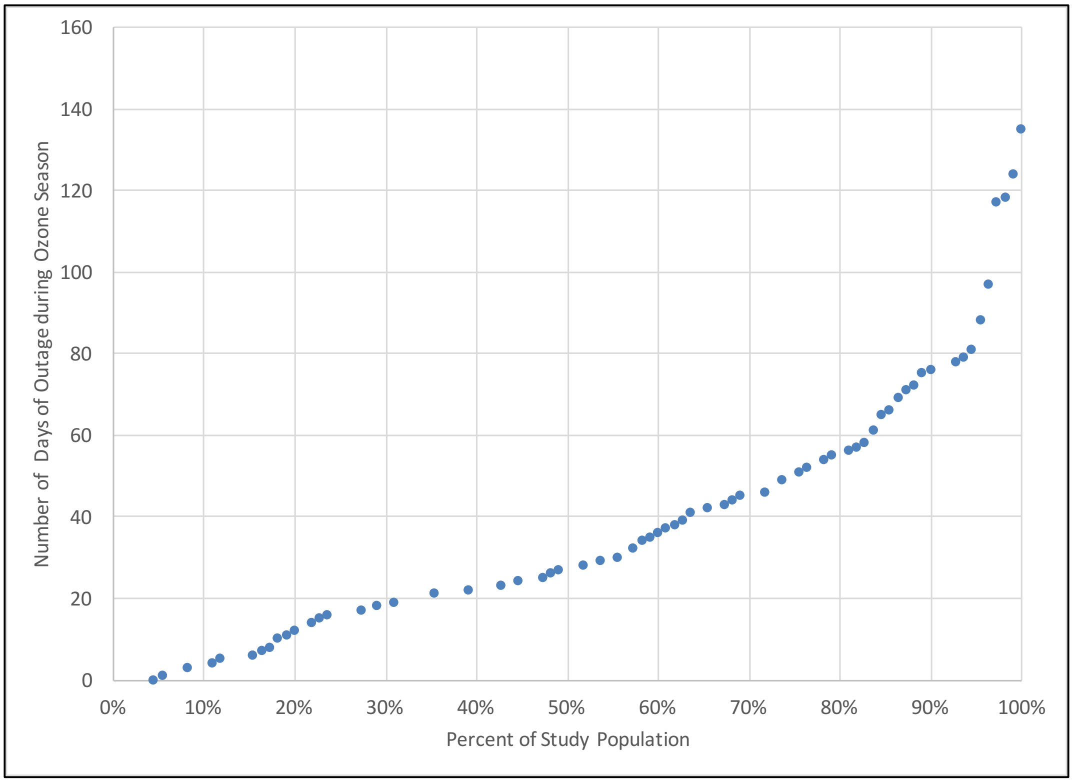

Figure 7-6. Count of Units Experiencing at Least One Hour of Outage

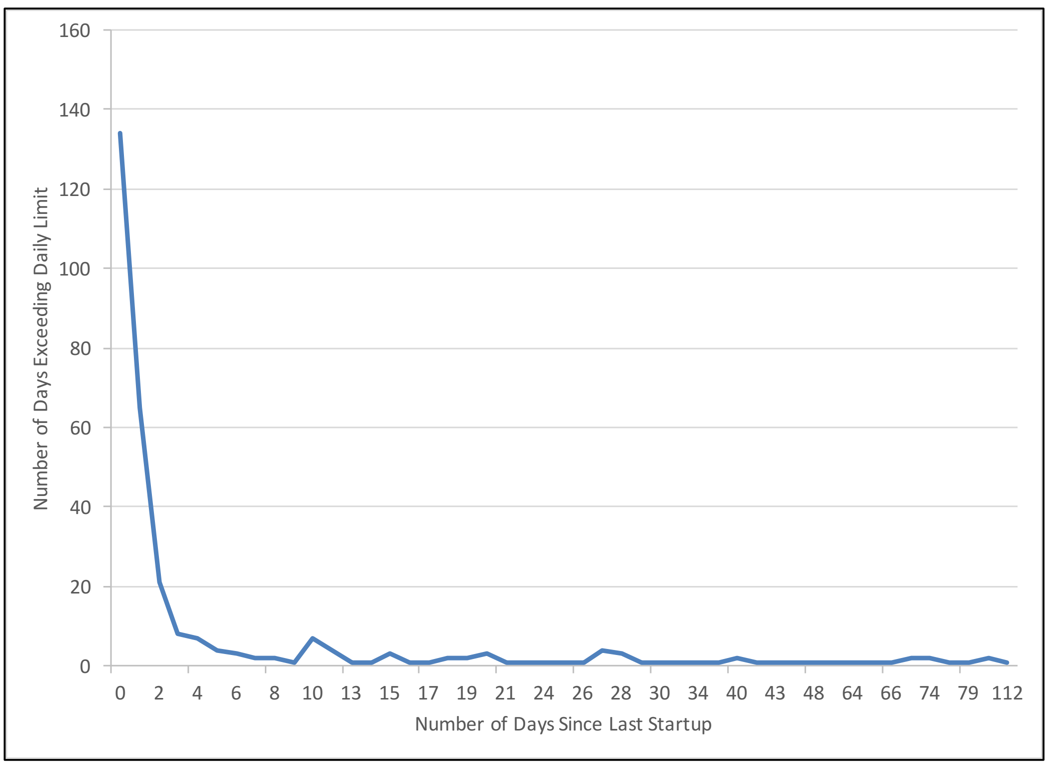

Figure 7-7. Role of Days Following Startup on Days Exceeding Daily Rate

Role of Days Following Startup. The operating time subsequent to a startup is one indicator potential for daily rate exceedances. Figure 7-7 presents data derived from the inventory of units operating over the 153 day 2021 ozone season, describing the number of days that exceed the proposed daily backstop rate.

Figure 7-7 shows operating within 1 full day of startup, a total of 65 observed days were recorded with NOx exceeding the 0.14 lbs/MBtu rate. But within a second day the observed days exceeding 0.15 was dropped by 1/3, to 21 total days. After 4 days such observations are negligible.

Role of Load. Operating load affects performance of the SCR process, with load less than 40% frequently inducing boiler outlet gas temperature below the minimum operating temperature for ammonia injection. At these conditions reagent is typically terminated to prevent possible catalyst damage from residual ammonia emissions.

Fossil-fuel generating units are presently under pressure to increase –not decrease - flexibility to operate for extended periods at low load to balance the grid and compensate for variable renewable generation. The need for coal-fired units to consistently operate at loads where SCR operation either is not optimal or must be terminated will increase, and not decrease, in future years. Retrofitting SCR limits the flexibility of coal-fired units to provide variable load.

Figure 7-8 reports the cumulative number of days that all units in the 110-unit study population exceeded the proposed backstop rate of 0.14 lbs/MBtu for the 2021 ozone season. The left axis reflects the fraction of total operating days in each load "bin" that exceeded the proposed backstop rate. For example, over the 2021 ozone season, units operating at or below the 20% load "bin" recorded a total of 390 days exceeding the proposed backstop rate – equal to 47% of operating days in that load bin. A similar number of operating days – 370 – were recorded for all units operating in the 21-40% bin with NOx exceeding the proposal backstop rate, comprising 12% of all operating days in that bin.

The combined operating time for these two low load categories – 756 days – represents conditions where SCR is not operating in an optimal state, or must be terminated as inlet gas temperature is below the minimum required for injection. At these conditions, the generating units operate with no material postcombustion control of NOx emissions. Conversely, above 80% load, 6,971 operating days were recorded with NOx emissions less than 0.14 lbs/MBtu.

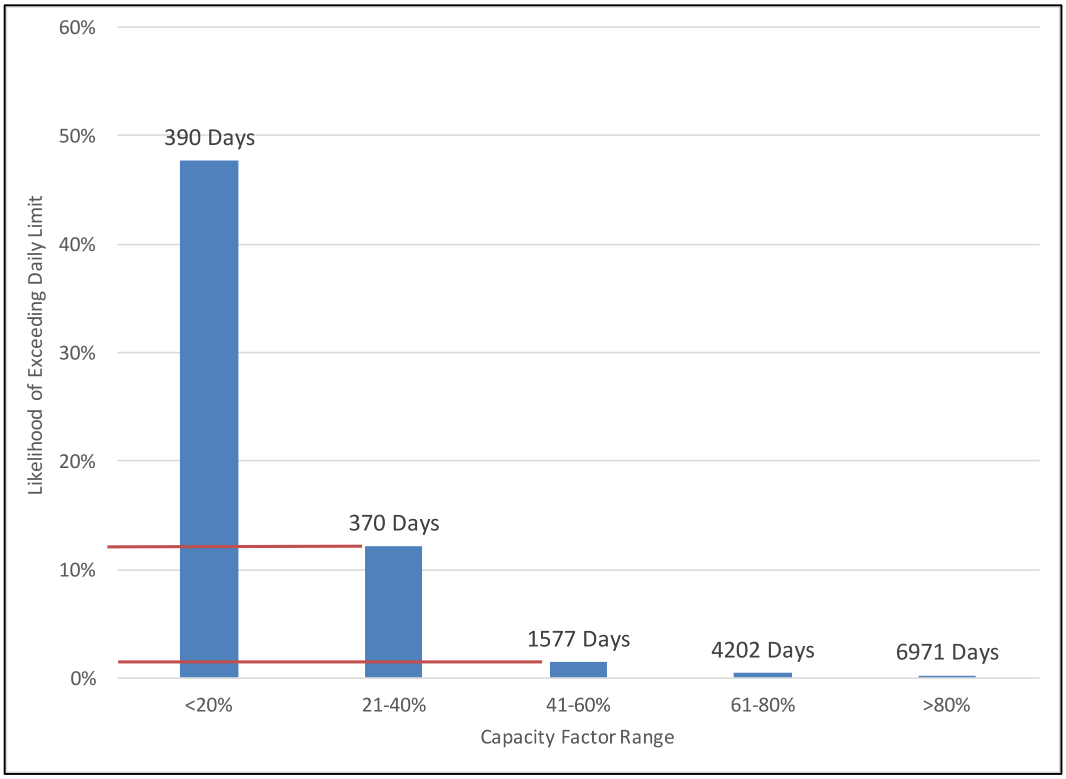

Figure 7-8. Role of Load Factor

These data show units in the select boiler population which meets the 0.08 lbs/MBtu limit, it is almost unavoidable to incur an outage and thus startup that causes a unit to emit more than 0.14 lbs/MBtu. Even altering the definition of how the rate is calculated - from a daily rate to a short-term, multi-day rate such as an average of 2 or 3 days –leaves significant number of operating events exceeding the 0.14 lbs/MBtu rate.

Table 7-1 compares the "count" of units that exceed the 0.14 lbs/MBtu proposed daily rate and the total number of days in which exceedances are observed – for three averaging methods. Table 7-1 shows the scope of lost operating time, with and without startup. There are no periods where a unit experiences startup/shutdown and does not exceed the proposed backstop rate.

Two observations are clear from Table 7-1. First, altering the calculation to consider a 2- or 3-day average lowers the count of units that experience exceedances, and the total count of exceedances – but does not eliminate them. Even if the EPA were to revise the proposal to employ a 3-day averaging period, a relatively large number of exceedances would still occur. In this data set, 62 are experienced by 24 units.

Second, it is unavoidable units will have outages – even eliminating the role of startup, there are unavoidable outage days for each averaging period that would prompt NOx emissions to exceed the proposed backstop rate.

Table 7-1. Units, Exceedances of Exceeding Proposed Backstop Rate of 0.14 lbs/MBtu

Proposal Rule Structure	Count of Units with Exceedances	Total Number of Exceedances
1-Day Average: with SU/SD	74	317
1-Day Outage: without SU/SD	52	183
1-Day Average: with SU/SD	53	149
1-Day Average: without SU/SD	22	46
1-Day Average: with SU/SD	24	62
1-Day Outage: without SU/SD	9	21

Longer averaging times do eliminate exceedances – specifically, calculating the 30-day average resulted eliminated any exceedances, even including startup/shutdown.

7.3 Takeaway

The introduction of a daily backstop rate – at the proposed value of 0.14 lbs/MBtu - will prompt even units with well-run SCR processes into exceedances, mostly due to unavoidable startup operation. An increase in averaging times to 3 day averaging period does not alleviate the considerable restriction that the daily backstop rate would impose. Imposing such a backstop will change the way units operate – and could compromise achieving the targeted NOx outlet rate of 0.08 or 0.05 lbs/MBtu. Specifically, an equipment malfunction – such as inadequate control over reagent injection - if left uncorrected to avoid a shutdown and exceeding the backstop rate, could compromise SCR operation at full load.

It should be noted owners are restricted in startup to abide by recommendations imposed by boiler and steam turbine suppliers. Specifically, the unit 'ramp rate" – the rate at which electricity generation can be increased and operating temperature of the SCR reactor attained – is defined by the SCR and catalyst supplier, and the steam turbine. The cost consequences of accelerating startup to minimize exceeding the backstop rate could damage steam turbine precision moving parts, incurring significant repair cost.

8. Generation Shifting

EPA proposes Generation Shifting as a means for NOx control, augmenting the proposed actions described in the previous sections. EPA considers Generation Shifting a step in establishing the State Budget Setting process- thus as a control step. Consequently, EPA's methodology for Generation Shifting is described here immediately subsequent to control technology.

The nine states selected to identify, evaluate and demonstrate issues with EPA's approach are: Arkansas, Indiana, Kentucky, Missouri, Ohio, Pennsylvania, Texas, West Virginia, and Wyoming. Generation Shifting occur not only with transport region program units but also non-program units such as, renewables, landfill gas, reciprocating units, and non-fossil capacity. [36] . In some states, a generation unit may have an equal reduction to an increase in generation, e.g., modeled as having the same GWh value produced from different sources. Therefore, units that contribute equally to loss and gain ("cancel") are not included in the generation shifting charts but are included in the overall Total GWh produced and NOx tons emitted per state.

EPA uses Generation Shifting to bias generation and NOx emissions from higher to lower NOx emitting sources. EPA uses the IPM where EPA's v6 models' regional breakdowns of net energy for load in each of the 67 IPM U.S. regions presented in the Figure 8-1.[37]

Generation Shifting is the third and final step in determining state budgets. Generation shifting is quantified by three IPM runs – Base Case, Run 1 and Run 2. The Base Case is the Integrated Planning Model (IPM) Summer 2021 Reference Case, while Run 1 represents base case optimization and LNB upgrade and Run 2 represents $1,800 per ton threshold. The Summer 2021 Reference Case is based upon electrical demand from EIA's Annual Energy Outlook 2020 and specific fuel prices and technology costs outlined IPM's most recent documentation.[38] In addition to these IPM runs, EPA adds a further calculation which determines the differential NOx emission rates between average IPM emission rates and Engineering Analytics emission rates. The minimum of these differential rates is applied to a state heat input to derive emission reductions, which are subtracted from the Optimized Baseline to yield a final state budget.

EPA's description of Generation Shifting is inadequate, and lacks of transparency on the steps and data used. Given the significance of Generation Shifting in affecting state budgets in some states, it is critical that EPA clearly explain how this step is down.

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[36] Non-Program units are not regulated by the proposal and do not contribute to the state budget or receive allowances. Non-Fossil do not qualify as biomass, but include waste products of liquid and gaseous renewable fuels.

[37] Figure 3-1 from EPA document. Available at: https://www.epa.gov/sites/default/files/2019-03/documents/chapter_3_0.pdf

[38] Documentation for EPA's Power Sector Modeling Platform v6: Using the Integrated Planning Model, September 2021.

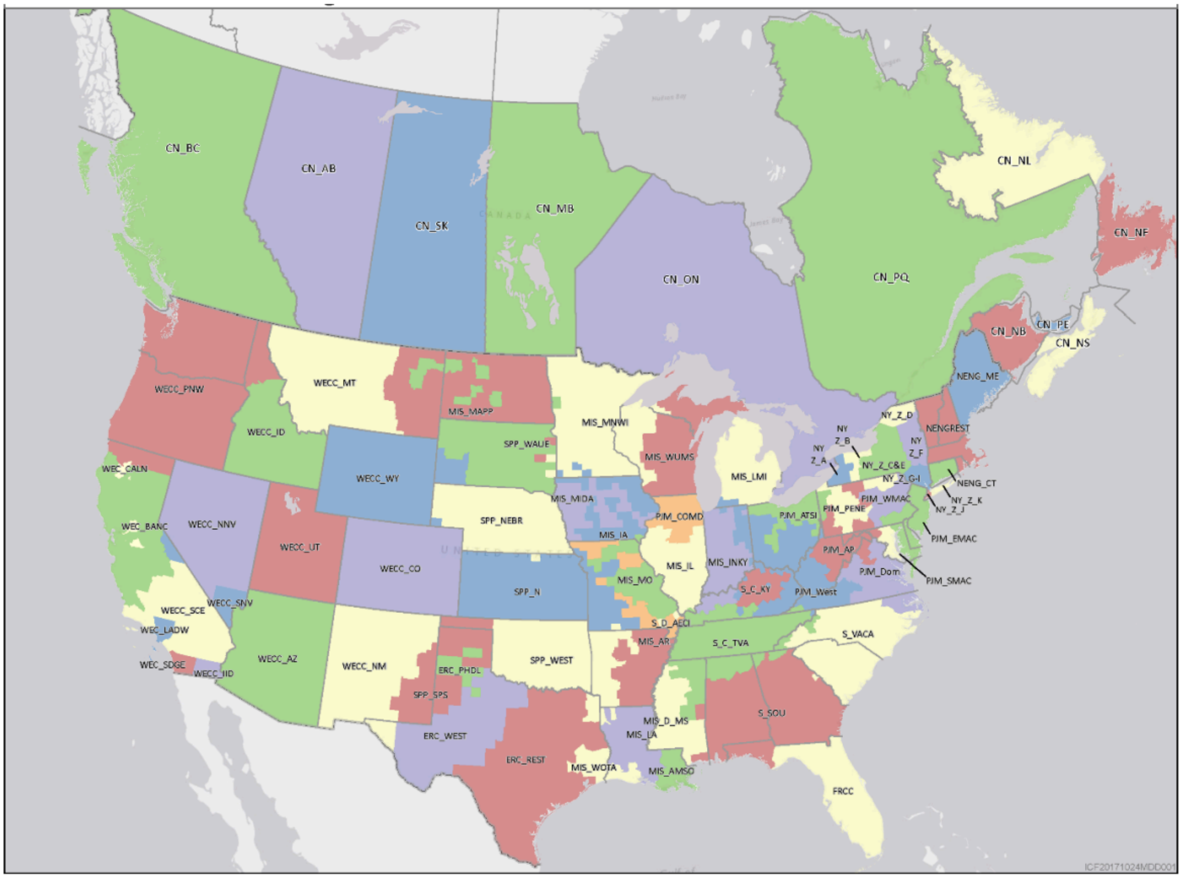

Figure 8-1. IPM Model: Definition of 67 Modeling Regions

8.1 Overview of Findings

Specific issues are identified and discussed addressing how shifting is used in state budgets. Generation Shifting is quantified by three IPM runs – Base Case, Run 1 and Run 2.

The Project Team only considered at generation shifting in 2023, since EPA indicated that by the 2025 budget year heat input should reflect such shifting in generation.[39] Of the three IPM runs that establish Generation Shifting results, the Base Case as the foundation is the most critical. However, the Base Case is flawed in that it does not represent the generating unit profile in many of the 25 states that comprise the proposed Transport Rule region.

Specifically, within the nine example states addressed in this analysis, in 2023 IPM erroneously retired 32 coal units representing 9.7 GW of capacity. None of the owners of these 32 units have announced retirement for 2023; notably 9 units totaling 6.6 GW are SCR-equipped and thus are expected to contribute to low NOx emissions. IPM also in 2023 idled 42 coal units representing 14.9 GW, also significant capacity with low NOx emissions. These 42 coal units that are idled by IPM do not generate any electricity in 2023. In regard to this outcome, NRECA previously

[39] 87 Fed Reg 20108.

expressed concern to EPA that IPM modeling does not capture the true cost of idling. Of these 42 units, 17 are SCR-equipped and represent 8.5 GW, despite featuring an average ozone season NOx rate of 0.07 lbs/MBtu. In addition, IPM idles an additional 14 coal units representing 7.4 GW of coal capacity during the 2023 ozone season.

Table 8-1 presents the coal capacity by state that EPA has either retired or idled in the nine example states evaluated. The table indicates that IPM has slightly over 28 percent of the operable coal capacity idled in the nine-state study region during the 2023 Ozone Season.

Table 8-1. IPM 2023 Retired and Idled Coal Capacity in the Nine-State Study Region (MW)

State	IPM Operable Coal Capacity	IPM Year-Round Idled Capacity	IPM Ozone Season Idled Capacity	IPM Retired Coal Capacity
AR	5,105	1,817	0	0
IN	11,147	1,118	4,252	0
KY	8,890	1,286	1,017	0
MO	9,417	275	0	240
OH	10,163	136	751	0
PA	1,964	112	767	6,958
TX	17,534	9,632	0	0
WV	11,220	520	80	0
WY	3,830	0	530	2,505
TOTAL	79,270	14,896	7,397	9,703

The flaws in the Base Case generation profile impart flaws in results from Run 1 and Run 2 (derived from the Base Case) that cannot accurately represent shifting of generation within a state. Specifically, EPA projects generation shifted to non-regulated sources (e.g., sources not covered in the Transport Rule), such as renewables, non-fossil, storage and industrial facilities as a consequence of eliminating low NOx emitting coal units due to retirements and idling. Most of these non-regulated sources are non-dispatchable facilities/units that cannot perform on demand.[40] This is particularly true for storage capacity, which is not a generating source and cannot provide enough electricity during the peak event. This becomes a major flaw in the modeling and can be attributed to the flaws in the Base Case. It should be noted, if a facility/unit is not shown, there was no shifting in generation modeled for that unit. Specifically, the facility/unit did not increase or decrease its generation in 2023.

Perhaps the most notable concern is EPA's erroneous assumption of unrestricted transfer of generation across a state, particularly so for states with multiple RTOs. EPA and IPM do not consider transmission constraints and the associated reliability issues that can occur during the height of the ozone season.

[40] A non-dispatchable source of generates electrical energy but cannot be turned on or off in order to meet demand. It is the opposite of dispatchable sources of electricity which flexible and able to change output quickly to meet electricity demands.

The Project Team recommends EPA eliminate the Generation Shifting step in the State Budget setting process and only use the Optimized Baseline values as the final state budget numbers.

Finally, EPA's Budget Setting Engineering Analytics and IPM Policy Case in 2026 NOx reduction potential are in conflict. EPA estimates 64,000 tons NOx reduction potential in 2026 from 42 GW of SCR retrofits on coal and 19 GW of SCR retrofits on oil/gas steam units. However, IPM projects a 47,000 tons NOx reduction in 2026 from 32 GW of EGU capacity being retrofitted with SCRs. This disconnect can be attributed the flawed IPM Base Case, which does not represent an accurate generation profile in the affected states.

Summary charts, are based upon the three IPM RPE output files for 2023 that can be found in the proposed rule's docket and that illustrates Generation Shifting in each of the nine states. Appendix A presents a map for each of the nine states identifying the location of the major generation sources for which Generation Shifting either increases or decreases generation output.

8.2 Arkansas

Figure 8-2 summarizes the generation-shifting in Arkansas, resultant to 3 IPM regions identified as MISO Arkansas, SERC Delta AECI, and SPP West (Oklahoma, Arkansas, Louisiana). The modeled runs are based on a total of 27,807 GWh of generation in Arkansas for 2023. Ten units are identified as part of generation shifting. Increases in GWh are primarily from the combined cycle Dell Power Station in SERC. Generation losses are solely from MISO. An Arkansas state map in Appendix A identifies the locations of the most significant sources affected.

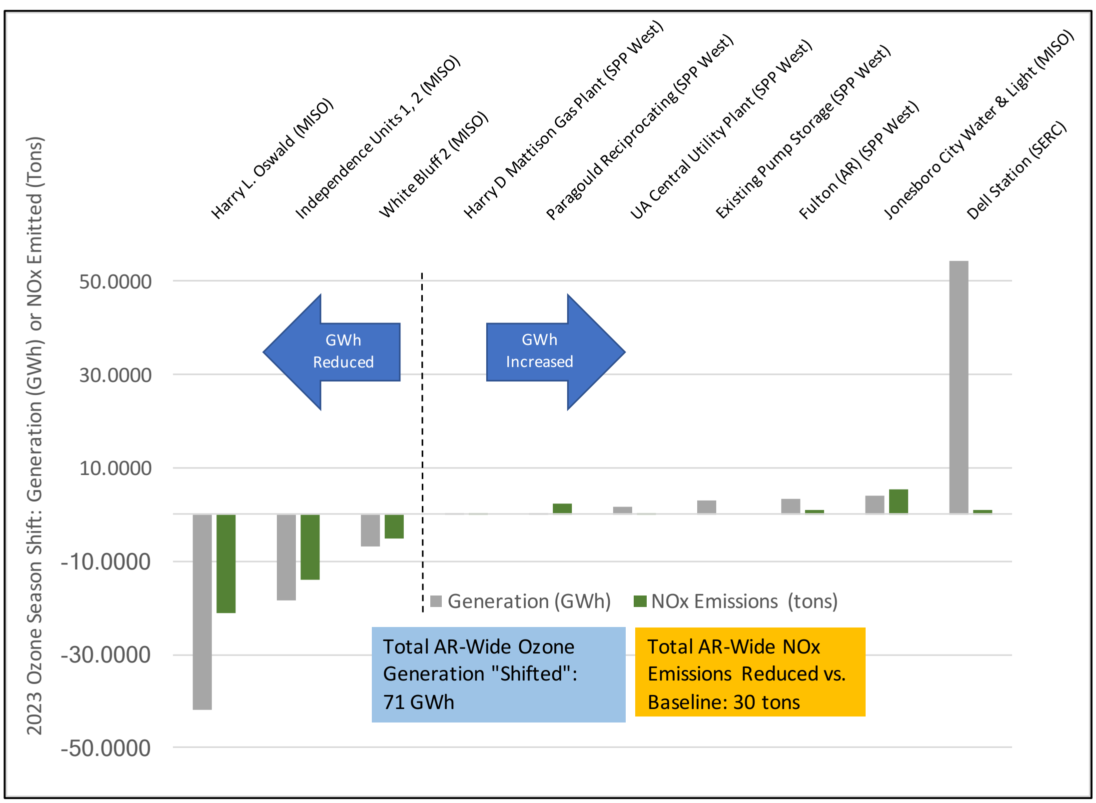

Figure 8-2. Generation Shifting Summary: Arkansas

Four units surrender generation: two coal (Independence Units 1, 2; White Bluff 2), one combined cycle (Harry L. Oswald), and a non-fossil unit. Non-program capacity pumped storage and Paragould Reciprocating pick up generation, which are non-dispatchable and not able to perform on demand. The generation shift of 71 GWh results in a reduction of 30 tons of NOx.

8.3 Indiana

Figure 8-3 summarizes the generation-shifting in Indiana, resultant from two IPM regions - MISO Indiana (including parts of Kentucky) and PJM West. The modeled runs are based on a total of 36,894 GWh generation in Indiana for 2023. All generation shifts occur within MISO. Sixteen units are identified as part of the generation shifting. Five units included have a generation net gain from Gibson 1-3, Gibson 5, Clifty Creek 4-5, Michigan City and Warrick 4, with a net loss from Warrick 1-3 and Clifty Creek 6 Since IPM idled 5.3 GW of Indiana coal capacity, to squeeze out additional NOx tons, IPM reduced generation from three non-program units, Warrick 1-3. The generation shift of 318 GWh results in a reduction of 335 tons of NOx. An Indiana state map in Appendix A Identifies the locations of the most significant sources affected.

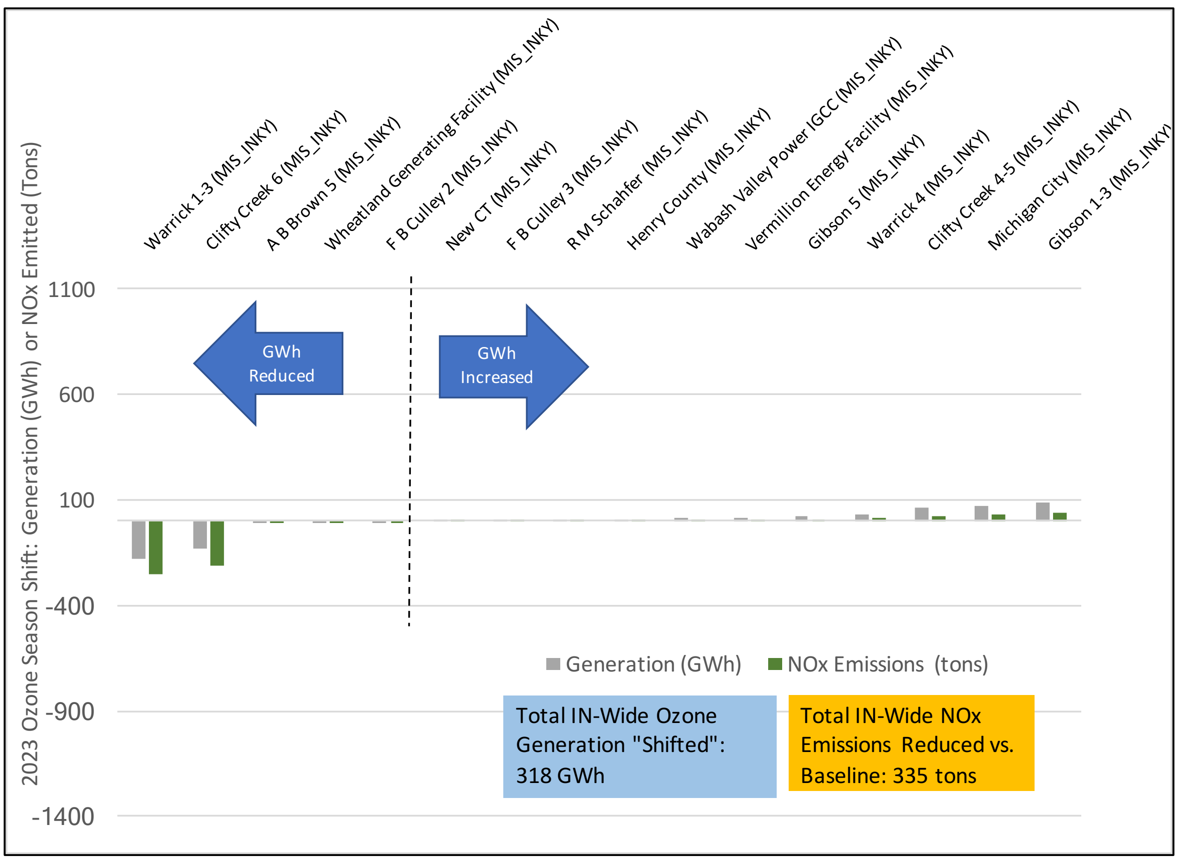

Figure 8-3. Generation Shifting Summary: Indiana

8.4 Kentucky

Figure 8-4 summarizes the generation-shifting in Kentucky, considering four IPM regions in–- MISO Indiana (including parts of Kentucky), PJM West, SERC Central Kentucky, and SERC Central TVA. The modeled runs are based on a total generation of 26,254 GWh in Kentucky for 2023. There is a net loss in PJM and SERC Central Kentucky, with the greatest net gain in MISO. Twenty-one units are identified as part of the generation shifting. Non-program units include a landfill gas facility which is non-dispatchable. A Kentucky state map in Appendix A identifies the locations of the most significant sources affected.

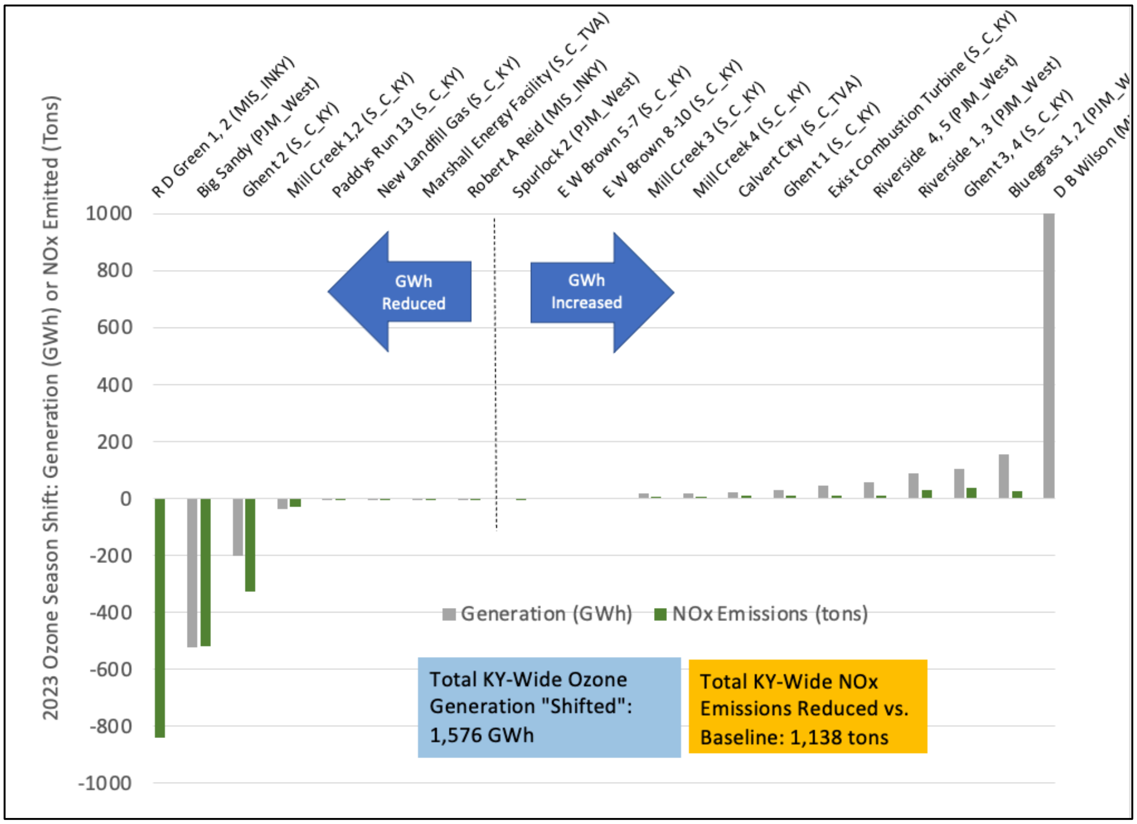

Figure 8-4. Generation Shifting Summary: Kentucky

IPM idled 2.4 GW of Kentucky coal capacity in 2023, many of which had post-combustion controls. As a consequence of this idling, IPM idled both RD Green 1/2 (MISO) and Big Sandy (PJM), and brought on-line during the ozone season a low emitting coal unit – DB Wilson (MISO)- to offset generation, resulting in generation being shifted between two RTOs The generation shift of 1,576 GWh results in a reduction of 1,138 tons of NOx.

8.5 Missouri

Figure 8-5 summarizes generation-shifting in Missouri, based on the four IPM regions of MISO Missouri, SERC Delta AECI, SPP North (Kansas, Missouri), and SPP West (Oklahoma, Arkansas, Louisiana). The modeled runs are based on a total generation of 35,627 GWh in Missouri in 2023. Loss in generation occurs only in MISO.

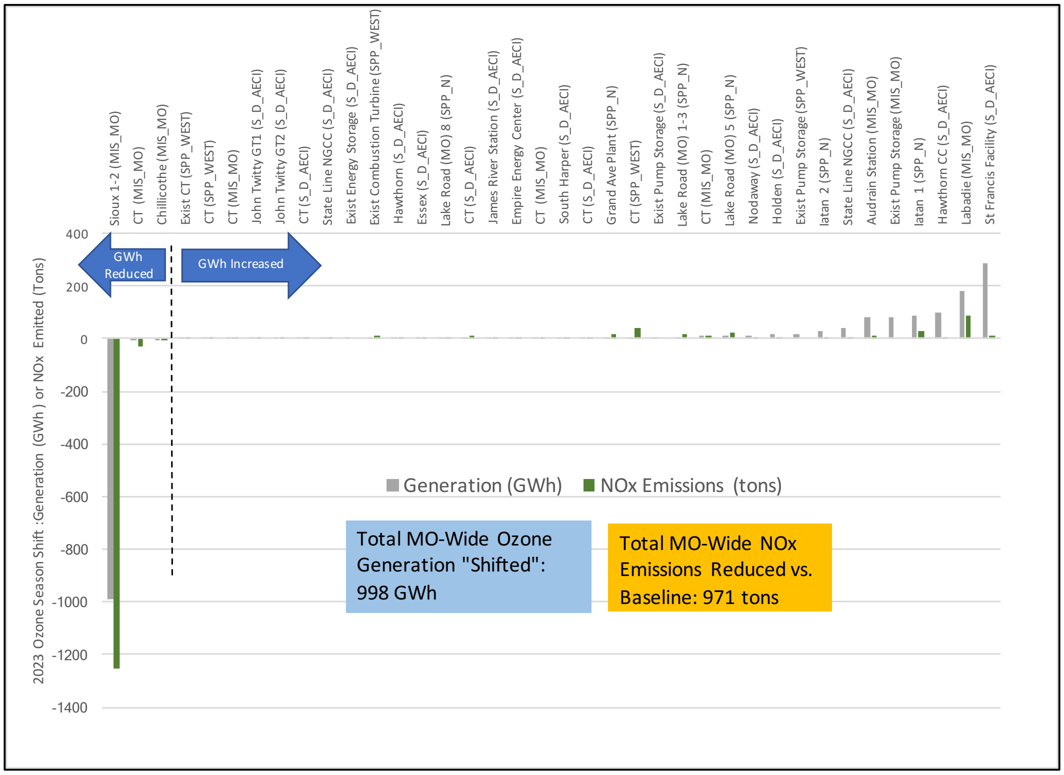

Figure 8-5. Generation Shifting Summary: Missouri

The major reduction is from Sioux 1-2, which is idled by IPM during the 2023 ozone season Thirty-eight units are identified as part of the generation shifting. Non-program units include an energy and pump storage, both non-dispatchable. The generation shift of 998 GWh results in a reduction of 971 tons of NOx and cuts across SERC, MISO and SPP A Missouri state map in Appendix A identifies the locations of the most significant sources affected.

8.6 Ohio

Figure 8-6 summarizes generation-shifting in Ohio, based on the IPM regions PJM ATSI and PJM West. The modeled runs are based on a total generation of 60,358 GWh in Ohio for 2023. The net reduction in PJM West of 529 GWh is balanced by the net increase in PJM ATSI.

Twenty-one units are identified as part of the generation shifting in Ohio, with WH Sammis 5 being idled in the ozone season. IPM includes three non-program, non-dispatchable resources – two non-fossil facilities and one biomass facility. The generation shift of 1,188 GWh results in a reduction of 717 tons of NOx. A Ohio state map in Appendix A identifies the locations of the most significant sources affected.

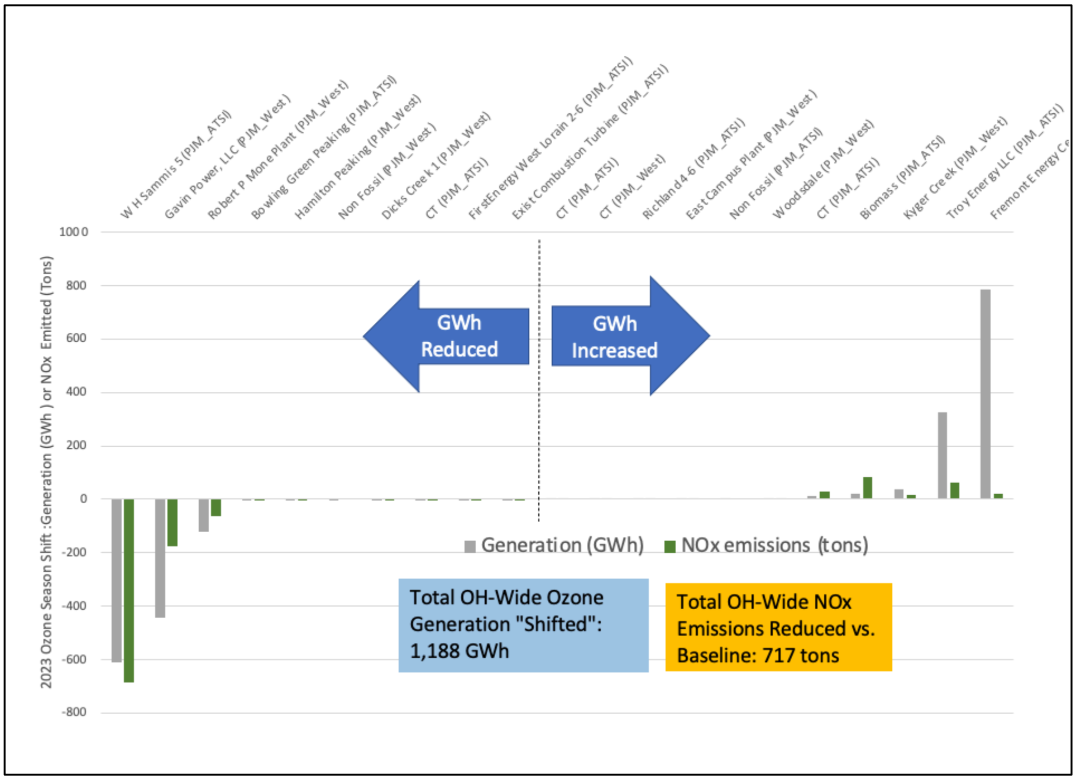

Figure 8-6. Generation Shifting Summary: Ohio

8.7 Pennsylvania

Figure 8-7 summarizes generation-shifting in Pennsylvania, across six IPM regions, all of which are within PJM. These are: AP, ATSI, EMAAC, PENELEC, West, and Western MAAC. The modeled runs are based on a total of 108,258 GWh in 2023, of which 12,499 GWh from PJM ATSI and PJM West do not contribute to the generation shifting. Net losses occur in Western MAAC and PENELEC, with increases AP and EMAAC. Twelve units are identified as part of the generation shifting, with two non-program, non-dispatchable resources (energy and pumped storage) are involved in picking up additional generation. One of the main contributing factors to the results in Pennsylvania, is that IPM retired almost 7.0 GW of coal capacity in 2023. The generation shift of 254 GWh results in a reduction of 3 tons of NOx. A Pennsylvania state map in Appendix A identifies the locations of the most significant sources affected.

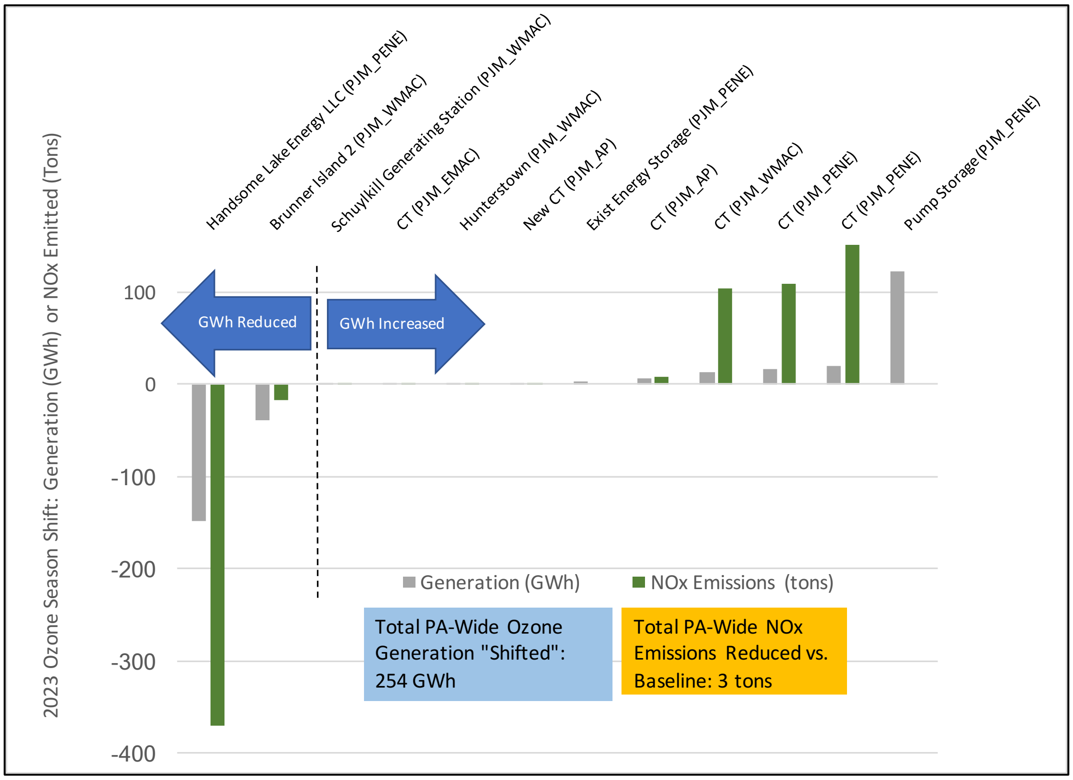

Figure 8-7. Generation Shifting Summary: Pennsylvania

8.8 Texas

The four main regions in Texas are ERCOT, MISO WOTAB (including Western), SPP, and WECC New Mexico. The IPM regions for SPP include SPS (Texas Panhandle) and West (Oklahoma, Arkansas, Louisiana). The IPM regions for ERCOT include the following five: Panhandle, Rest, Tenaska Frontier Generating Station (Frontier), Tenaska Gateway Generating Station (Gateway), and West. The modeled runs are based on a total generation of 217,853 GWh in the state for 2023, of which 187,971 GWh are from two IPM ERCOT regions (Rest, West). The other three ERCOT regions do not contribute to the generation shifting. SPP contributes 15,404 GWh, MISO contributes 11,835 GWh, and WECC 2,643 GWh. Statewide, fifty-eight units participate in generation shifting. Non-program, non-dispatchable units include biomass and storage units. The Texas-wide generation shift of 2,435 GWh reduces 1,034 tons of NOx.

Three figures are presented for Texas. Figure 8-8 summarizes generation shifting across the four main regions. EPA's Generation Shifting strategy involves ERCOT and non-ERCOT regions. IPM models SPP losing up to 40.3 GWh of generation in 2023 and ERCOT gaining 25.1 GWh of generation, with MISO and WECC gaining 4.2 GWh and 11.0 GWh, respectively. This modeled generation shift presents a major flaw. Specifically, generation from ERCOT cannot transfer to SPP and only ERCOT can shift generation within ERCOT. Another modeling issue is the CT capacity acquiring generation - CTs are generally designed to produce at peak only. CTs may not have sufficient authorization for operation at higher rates for additional emissions. Figures 8-9 and 8-10 separate ERCOT and non-ERCOT regions, respectively. A Texas state map in Appendix A identifies the locations of the most significant sources affected.

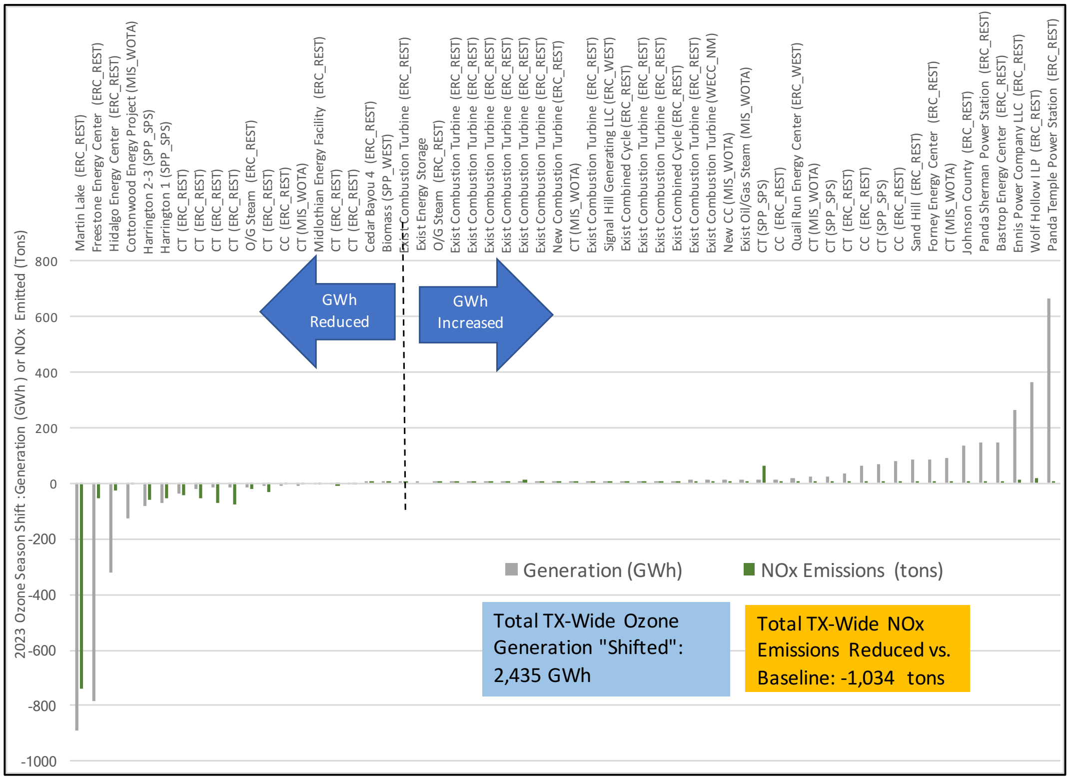

Figure 8-8. Generation Shifting Summary: Texas

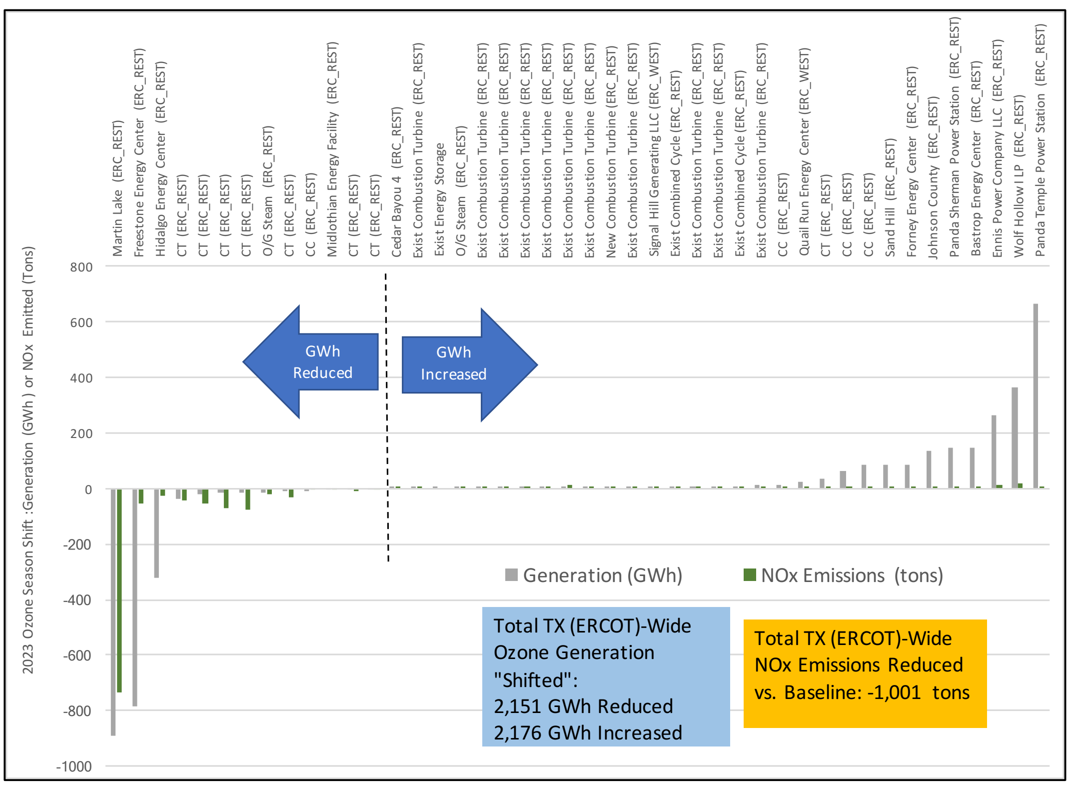

Figure 8-9. Generation Shifting Summary: Texas, ERCOT

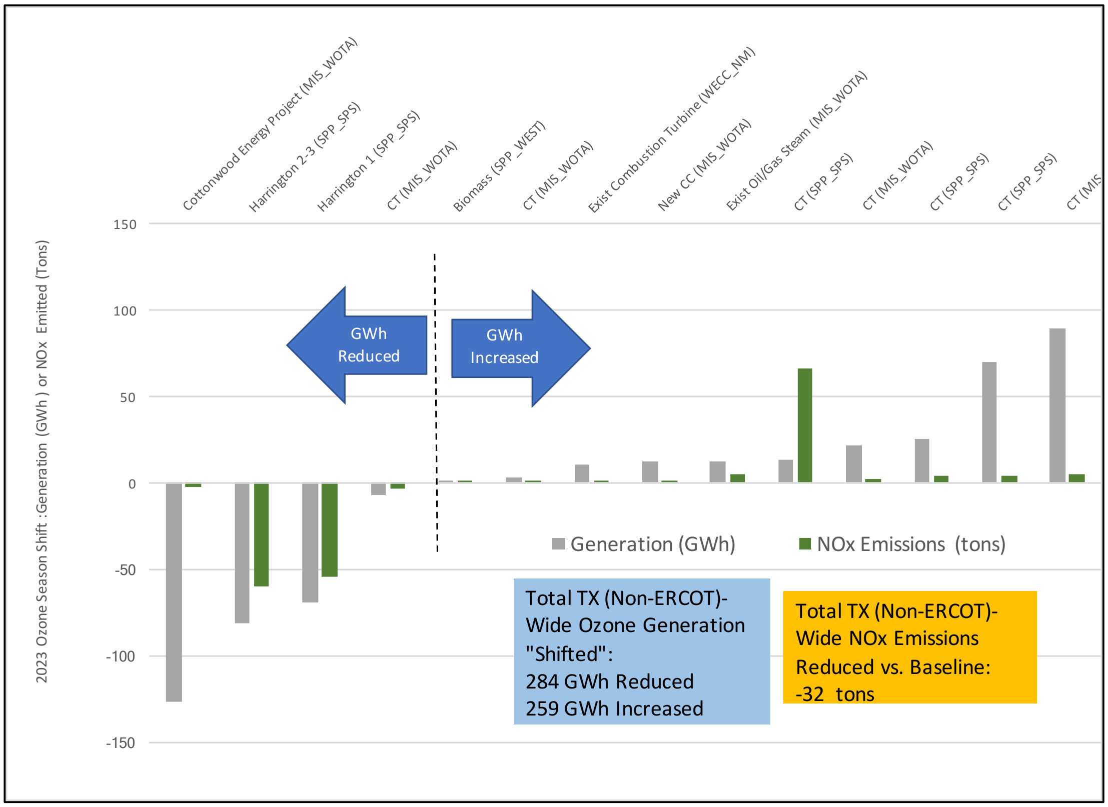

Figure 8-10. Generation Shifting Summary: Texas, Non-ERCOT

8.9 West Virginia

Figure 8-11 summarizes generation-shifting in West Virginia, based on West Virginia IPM regions PJM AP and PJM West, which are all within PJM The modeled runs are based on a total of 26,717 GWh in West Virginia for 2023. The net reduction in PJM AP of 777 GWh is directly balanced out by the net increase in PJM West. Five units are identified as part of the generation shifting Modeled generation loss is primarily from idling Fort Martin Power 2 during the ozone season. The generation shift of 1,124 GWh results in a reduction of 1,123 tons of NOx. A West Virginia state map in Appendix A identifies the locations of the most significant sources affected.

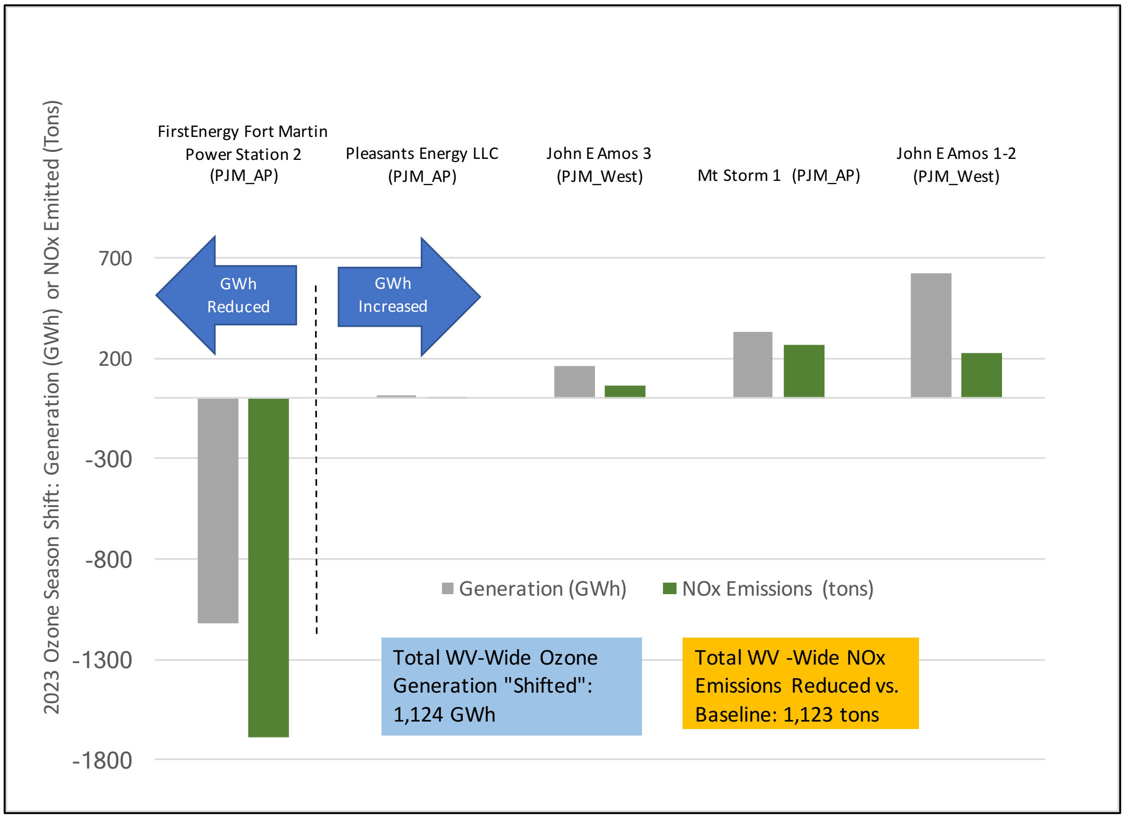

Figure 8-11. Generation Shifting Summary: West Virginia

8.10 Wyoming

Figure 8-12 summarizes generation-shifting for the sole IPM region in Wyoming - WECC Wyoming. The modeled runs are based on a total of 14,013 GWh of generation in Wyoming for 2023. Generation reductions are mainly from Laramie River Station (LRS) 2 and 3, two non-SCR units, with Jim Bridger 4 proving the majority of generation increases. Eight units are identified as part of the generation shifting including a non-program CT - Arvada-Barber Creek-Hartzog. The generation shift of 1,090 GWh results in a reduction of 460 tons of NOx. A Wyoming state map in Appendix A identifies the locations of the most significant sources affected.

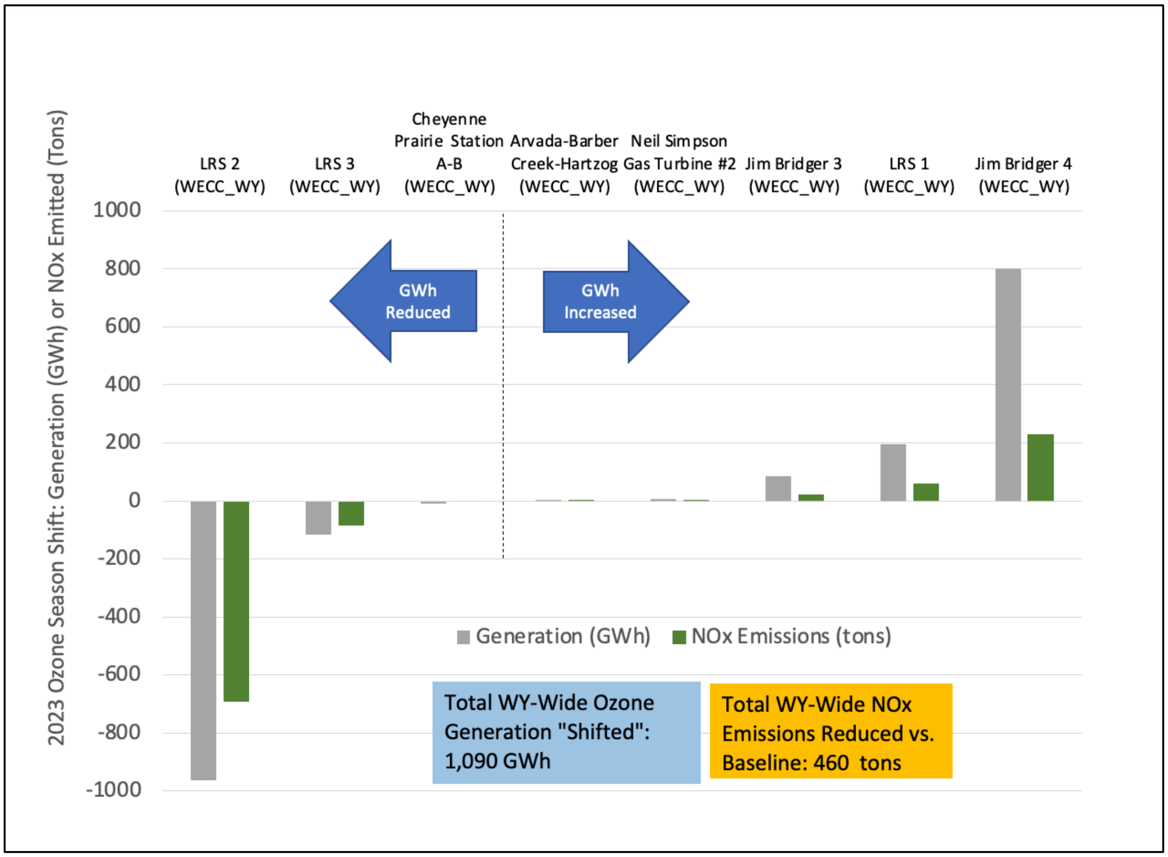

Figure 8-12. Generation Shifting Summary: Wyoming

The implications of faulty IPM modeling related to Generation Shifting on individual state distorts the assignment of allowance allocations within the nine states. Table 8-2 summarizes the Generation Shifting step has cost the nine states 6,054 allowances.

Table 8-2. Allowances Lost to Generation Shifting in 2023

State	Allowances Lost
AR	38
IN	335
KY	1,213
MO	668
OH	765
PA	409
TX	1,422
WV	828
WY	376
TOTAL	6,054

9. State Budgets, Emissions Allocations, and Reliability

Section 9 addresses issues related to the state budgets for the 25-state proposed Transport Rule, and the impact of assigned state budgets on allowance allocation and reliability.

9.1 State Budget Setting Process

EPA's State Budget Setting Process under the proposed Transport Rule contains numerous errors and omissions, and adopts incorrect assumptions pertaining to technology deployment and NOx emission rates.

The Project Team selected as examples nine states within the 25-state Transport Rule region to evaluate; however, EPA needs to review all the state budget setting process to ensure the accuracy of the budget process. These states selected for sample analysis - Arkansas, Indiana, Kentucky, Missouri, Ohio, Pennsylvania, Texas, West Virginia and Wyoming – represent different geographic sectors of the Transport Region. These states also represent various RTOs and different utility structures (IOUs, Public Power and Cooperatives).

9.1.1 Identification of Errors and Omissions

EPA's Budget Setting Process did not accurately assign NOx emission rates to SCR and non-SCR units sharing a common stack. Table 9-1 lists those SCR-equipped units in both Indiana and Kentucky that share a common stack with non-SCR-equipped units, as determined from discussions with unit operators.

Table 9-1. 2021 Unit Emission SCR Emission Rates (lbs/MBtu)

Unit	2021 SCR Rates (lbs/MBtu)
Clifty Creek 4 and 5	0.07
Ghent 3	0.021
Cooper 2	0.06
Shawnee 1	0.048
Shawnee 4	0.062

Correcting NOx emissions from SCR–equipped units to a lower value increases the NOx tons assigned to the non-SCR-equipped unit, as total common stack emissions must remain the same. If the non-SCR-equipped unit features state-of-the-art combustion controls, any such revision of assigned NOx tons increases the budget for 2024 and forward years. If the non-SCR-equipped unit does not have state-of-the-art combustion controls, the 2024 and forward NOx emissions are adjusted based upon retrofitting the unit with a state-of-the-art emission factor.

EPA's Budget Setting Process did not accurately reflect natural gas conversions in the nine-state study region and it is anticipated that EPA has made similar errors in the remaining states to covered by the proposed rule. EPA either did not correctly identify the timing of a natural gas conversion or utilize the appropriate post-conversion NOx emission rate in the State Budget Setting process. Table 9-2 lists units for which conversion to natural gas is planned for which EPA needs to adjust the timing or emission rates in the State Budget Setting process.

Table 9-2. Natural Conversions in the Nine State Study Area

State	Unit	Change
KY	RD Green 1 & 2	Change unit emission rates of 0.17 for 2023
PA	Brunner Island 1-3	Begin burning only gas between May and September in 2023 to generate 0.15 lbs/MBtu
PA	Montour 1 & 2	Possible conversion to natural gas in 2025 at an emission rate of 0.04 lbs/MBtu
WY	Jim Bridger 1 & 2	Conversion to natural gas in 2024 at emission rates of 0.09 (Unit 1) and 0.084 (Unit 2) lbs/MBtu
WY	Neil Simpson II (001)	Conversion to natural gas in 2025 at an emission rate of 0.075 lbs/MBtu

EPA also incorrectly assumes several unit retirements dates which significantly affect a state budget. Table 9-3 lists corrections required to remedy errors in retirement dates.

Table 9-3. Retirement Date Changes in the Nine State Study Area

State	Unit	Change
IN	Merom 1 & 2	Hoosier sold the plant to Hallador Power, which expects to operate beyond 2027
IN	Schahfer 17 & 18	NIPSCO delaying retirement until 2025, as replacement capacity could not be acquired
MO	Rush Island 1 & 2	To be retired in 2024
WY	Naughton 1 & 2	To be retired in 2025
WV	Pleasants 1 & 2	To be retired in 2023

9.1.2 Technology Assignment Issues

In reviewing unit information with owners, the Project Team identified incorrect technology inventory data that need to be addressed in determining final state budgets. Table 9-4 presents examples of EPA's errors in technology inventory.

Table 9-4. Technology Assignment Issues in the Nine State Study Area

State	Unit	Change
IN	Whitewater Valley 1 & 2	Does not have an operating SNCR
KY	Bluegrass Generating Units 1,2 &3	Not equipped with SCR
KY	Cane Run CC	Not equipped with SCR
MO	Sikeston Unit 1	Not equipped with SNCR
MO	John Twitty CT1A	Not equipped with SCR
OH	AMP Gas Turbines	Uses default emission factors in 75.19 as a Low Mass Emitting (LME) unit
PA	Helix Ironwood	Not equipped with SCR
PA	Seward	The plant operated SNCR in the 2021 Ozone Season
TX	Newman GT6A	Not equipped with SCR
TX	San Miguel	The unit operated SNCR in the 2021 Ozone Season
TX	Silas Ray 9	Not equipped with SCR

9.1.3 Technology Deployment Issues

As discussed in Section 4, the timing for installation of Combustion Controls and SCR processes should be revised to determine state budgets in 2023 and 2026. Specifically, Combustion Controls require on average 22 months from project inception to commercial operation, and thus will not be available for the 2023 Ozone Season (see Section 4.5). The earliest time for which Combustion Controls could be operational is the 2024 Ozone Season, which is consistent with the language in the proposal that says state-of-the-art combustion controls are to be readily available at the start of the 2024 ozone season[41]. This is contrary to how EPA established the 2023 state budgets, which assumed the availability of combustion controls in 2023. New SCR retrofits will require 40 months on average, and thus will not be broadly available until the 2027 Ozone Season (per information from 18 SCR installations reported in Section 5.3). In calculating the state budgets for 2023, EPA should revise its methodology and not presume Combustion Controls will be operating until the 2024 Ozone Season, and SCR will not be broadly available until the 2027 Ozone Season.

EPA uses a single emission rate for Combustion Controls (0.199 lbs/MBtu) and thus fails to consider fuel and boiler type, which as discussed in Section 4 assert a significant impact on achievable NOx emission rate. Table 9-5 presents achievable NOx emissions on a fleet average basis, and should be used is establishing emissions attributed to the 2024 budget year.

[41] 87 Fed Reg 20079.

Table 9-5. Average Achievable NOx Emission Rates (lbs/MBtu)

Coal Rank	Tangential-Fired	Wall-Fired
Bituminous	0.28	0.32
Lignite	0.20	0.22
Subbituminous	0.15	0.19

In addition to issues related to the calculation of state budgets, EPA has incorporated in Appendix A of the *Ozone Transport Policy Analysis Proposed Rule TSD* each units' gross generation and generating capacity, and computed capacity factors. Although the description of Appendix A material is incomplete, it appears capacity values are reported on the basis of *summer net*, implying an appropriate capacity factor that requires knowledge of net and not gross generation. The Project Team could not reproduce capacity factors listed in Appendix A. The inability to corroborate EPA's calculations creates concerns Appendix A data does not correctly establish the threshold NOx emission rate of 150 tons per year that determines if oil/gas-fired units are required to deploy SCR.

9.1.4 Recalculation of State Budgets

Based upon issues and omissions identified, EPA should review and adjust all state budgets beginning with budget year 2023. The focus of these adjustments should reflect: (i) the timing for installation of Combustion Controls in 2024 and retrofit of SCR in 2027; and, (ii) the correct technology inventory, and (iii) accurate NOx emission rates and retirements.

The Project Team recalculated budgets for the nine example states based upon the information described in Section 9.1 for the years 2023 and 2026. Table 9-6 compares the Optimized Baseline developed by EPA in the proposal to a Recalculated Optimized Baseline. The Optimized Baseline consists of retirements, natural gas conversions, and new SCR processes installed prior to the budget year, plus adjustments to the baseline from SCR and SNCR Optimization and Combustion Controls.

Table 9-6 contrasts the Optimized Baselines for each state - the state budgets under the proposed Transport Rule. The Generation Shifting step of the State Budget Setting process should be eliminated, which is discussed in Section 8.

Utilizing the revised timing and technology/retirement adjustments will increase Optimized Baseline values; thereby increasing state budgets for each of the nine states in both 2023 and 2026. The Project Team recommends EPA evaluate each state and employ the type of adjustments identified and revise the state budgets.

Of particular note, EPA is presenting inconsistent data or has erred in estimating the tons of NOx reduced in the nine states that are attributed to 2023 generation shifting. These discrepancies appear in the table below and are from Proposed Appendix A Proposed Rule State Budget Calculations and Engineering Analytics Spreadsheet and Appendix D-1 of the Ozone Transport Policy Analysis Proposed Rule TSD.

Table 9-6. Recalculated State Optimized Baselines: 2023 and 2026

State	Year	Optimized Baseline (Ozone Season Tons)	State Budget (Ozone Season Tons)	Recalculated Optimized Baseline (Ozone Season Tons)
AR	2023	8,927	8,889	8,927
	2026	4,031	3,923	8,702
IN	2023	11,486	11,151	12,556
	2026	7,997	7,791	9,033
KY	2023	12,853	11,640	14,182
	2026	7,761	7,573	12,681
MO	2023	12,525	11,857	12,531
	2026	7,373	7,246	11,047
OH	2023	9,134	8,369	9,140
	2026	8,941	8,586	9,089
PA	2023	9,264	8,855	8,675
	2026	7,228	6,819	8,448
TX	2023	39,706	38,284	39,752
	2026	23,369	21,946	35,842
WV	2023	13,306	12,478	13,849
	2026	11,026	10,597	12,452
WY	2023	9,501	9,125	11,607
	2026	4,580	4,490	8,635

Table 9-7 shows six of the nine states exhibited discrepancies in the role of generation shifting, based on comparing the two sources. These discrepancies further reinforce the argument that the generation shifting step in the State Budget Setting process should be eliminated.

Table 9-7. 2023 Generation Shifting Discrepancies

State	Appendix A Budget Shifting Tons	Appendix D-1 Budget Shifting Tons
AR	38	38
IN	**335**	**326**
KY	1,213	1,213
MO	**668**	**444**
OH	765	765
PA	**409**	**309**
TX	**1,422**	**1,190**
WV	**828**	**547**
WY	**376**	**958**

9.1.5 Non-SCR Unit Retirements between 2026 and 2030

Utility owners are planning to retire or cease firing coal at 29 non-SCR-equipped coal units between 2026 and 2030, representing 17.8 GW of capacity in the 25 State Transport Region (See Appendix A). These units should be exempted from the Backstop Emission Rate of 0.14 lbs/MBtu. Since there will be no NOx emissions when they retire, for budget setting purposes their emission rate for the 2026 thru 2030 budget years should be based upon the optimization of current controls.

9.1.6 2021 Baseline

The State Budget Setting process employs data at one point in time - 2021 – to project state budgets for 2023 and 2024. This approach is flawed as future electric utility operations based upon one historical year will not represent volatility in fuel prices and demand. This static approach does not account for changing dispatch conditions and unit performance, specifically changes in load. For example, a unit may meet EPA's mandated emission rate at a particular point in time, based on historical heat input which will not reflect future unit operations – which could be compromised due to greater operating duty at minimum load. This static approach also commits units to a fixed capacity factor for state budget purposes. EPA should consider an alternative approach that consider changes in demand in computing individual state budgets.

9.2 Emission Allowances and Reliability

The major concern of electric generators beginning in 2023 is their ability to meet demand and insure system reliability under the proposed rule's state allowance allocation system. As shown in Table 9-8, many electric generating units will not be able to comply with their allowance allocations in 2023.[42] More specifically, looking at the nine example states addressed in this evaluation, the Project Team estimated an overall allowance shortfall of 6,310 allowances during 2023 Ozone Season.

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[42] Generation forecast was based upon EIA's AEO22 regional electric generation forecasts by fuel type and takes into account retirements, technology deployment schedules and EPA mandated technology emission rates for SCR-equipped units. The 2023 allowances assume a redistribution of unused New Source Set-Aside allowances.

Table 9-8. EGU 2023 Ozone Season Emission and Allocations by State

State	2021 Ozone Season Emissions	2023 Ozone Season Emissions	2023 Allocations	Deficit/Overage
AR	8,955	8,047	8,889	842
IN	14,162	12,595	11,111	-1,484
KY	14,571	14,146	11,640	-2,506
MO	20,388	11,705	11,857	152
OH	11,728	9,961	8,077	-1,884
PA	12,792	8,488	8,782	294
TX	42,760	37,595	38,206	611
WV	14,686	13,607	12,478	-1,129
WY	11,643	10,331	9,125	-1,206
Total	151,684	127,615	120,165	-6,310

Surplus allowances – where estimated for some states - are extremely limited in supply, leaving negligible margin for unforeseen events. The limited allowance market implies allowance purchase will be costly. Consequently, EPA may consider establishing a "Price Ceiling" for such allowances, similar to the structure of the allowances managed for the California Cap-and-Trade Program for CO_2.[43]

One additional evaluation by the Project Team considered the 2026 Ozone Season emissions and allocations for Kentucky and Texas, as shown in Table 9-9.

Table 9-9. Electric Generating Unit 2026 Ozone Season Emissions and Allocations

State	2021 Ozone Season Emissions	2026 Ozone Season Emissions	2026 Allocations	Deficit/Overage
KY	14,571	11,794	7,675	-4,119
TX	42,760	30,975	22,195	-8,780

A revision of EPA's budget-setting methodology is required to address this potential negative impact in reliability.

Table 9-9 shows Kentucky and Texas experience significant allowance shortfalls in 2026, even with decreasing ozone season emissions. The 2026 Effective Allowance Emission Rate for both Kentucky and Texas is expected to be 0.048 lbs/MBtu and 0.028 lbs/MBtu, respectively.[44] These Effective Allowance Emission Rates, along with the allowance shortfall in each state will

[43] https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/cost-containment-information/price-ceiling-information

[44] The 2026 ozone season emission levels in both Kentucky and Texas assume retrofit SCRs would not be operable until the 2027 ozone season and 2026 allowances assume a redistribution of unused New Source Set-Aside allowances.

constrain how electric utilities will meet demand during the 2026 ozone season. Some utilities may have to constrain operation of coal units, possibly by idling during the ozone season or operating at limited output. These limitations on unit operations can be traced to how the state budgets are determined, such as employing a single year to predict the future thereby locking units into a specific capacity factor. Any limits on unit operation due to allowance shortfalls - with already tight reserve margins – will prompt reliability issues.

An additional reliability issue could result from the approximate 79 units representing 42 GW of coal-fired capacity in the 25-state Transport Region required to retrofit SCR in 2026. Texas and Kentucky alone have 25 units representing 11.8 GW of coal capacity, almost 30 percent of the affected inventory. Many of these units could be forced into retirement in the next four years due to the punitive economics of retrofitting SCR.

Finally, reliability concerns – discussed subsequently - have been identified in the Western half of the United States for the 2022 summer. The proposed Transport Rule could exacerbate these issues for operation in the 2023 ozone season. Specifically:

ERCOT

- ERCOT is forecasting record summer demand in Texas but is confident of capacity. However, ERCOT told Calpine to delay its scheduled repairs and keep plants operating to meet the demand in the hotter-than-expected May. On May 13, a malfunction removed a Calpine unit from service; by 5 PM of May 13, a total of six plants (2,900 MW) had gone offline and ERCOT required consumers lower demand.[45]

- Texas has boosted reserve margins through the addition of wind and solar generation, but NERC still considers ERCOT an elevated risk due to the potential of extreme weather and the ongoing drought.[46]

MISO

- In its Seasonal Readiness Workshop Summer 2022, MISO projected a warmer-than-normal-summer and likely capacity shortfalls in June, July and August. MISO is forecasting in its Probable Generation Scenario a July peak at 124 GW, with 118.5 GW of probable generation available. According to MISO, emergency resources and non-firm energy imports will be needed to maintain system reliability.[47]

- MISO's 2022/2023 Planning Resource Auction (PRA) further supports a capacity shortfall for the MISO North/Central Regions. Despite importing over 3,000 MW, MISO

[45] Mitchell Ferman, *Texas Grid Operator Told a Power Plant to Delay Repairs Ahead of a May Heat Wave. It Was Among Six Crashed*, Texas Tribune, May 17, 2022.
[46] North American Electric Reliability Corporation (NERC), *2022 Summer Reliability Assessment* (SAS), May 2022.
[47] MISO, *Seasonal Readiness Workshop Summer 2022*, April 28, 2022.

may not be able to meet demand. The auction indicates MISO North/Central Regions have a slightly increased risk to implement temporary controlled load sheds.[48]

SPP

- SPP anticipates sufficient resources to meet 2022 Summer Demand; however, NERC considers SPP an elevated risk in extreme weather events. NREC indicated the persistent drought in the Missouri River Basin could disrupt hydropower production and affect fossil units that use the river for heat rejection, which limit generator output - leading to energy shortfalls at peak demand periods. Above normal wind generation may provide some relief; however, this energy is not assured according to NERC.[49]

A revision of EPA's budget-setting methodology is required to address this potential negative impact in reliability.

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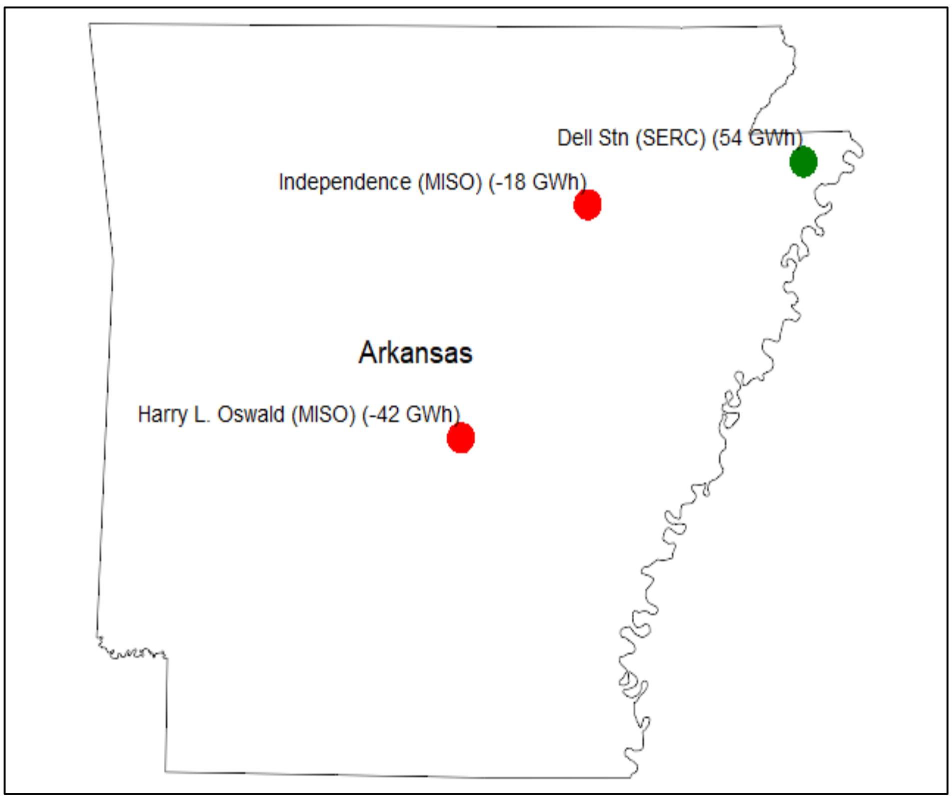
[48] MISO, *2022/2023 Planning Resource Auction (PRA) Results*, April 14, 2022.
[49] NERC, *SAS*, May 2022.

Appendix A: State Maps

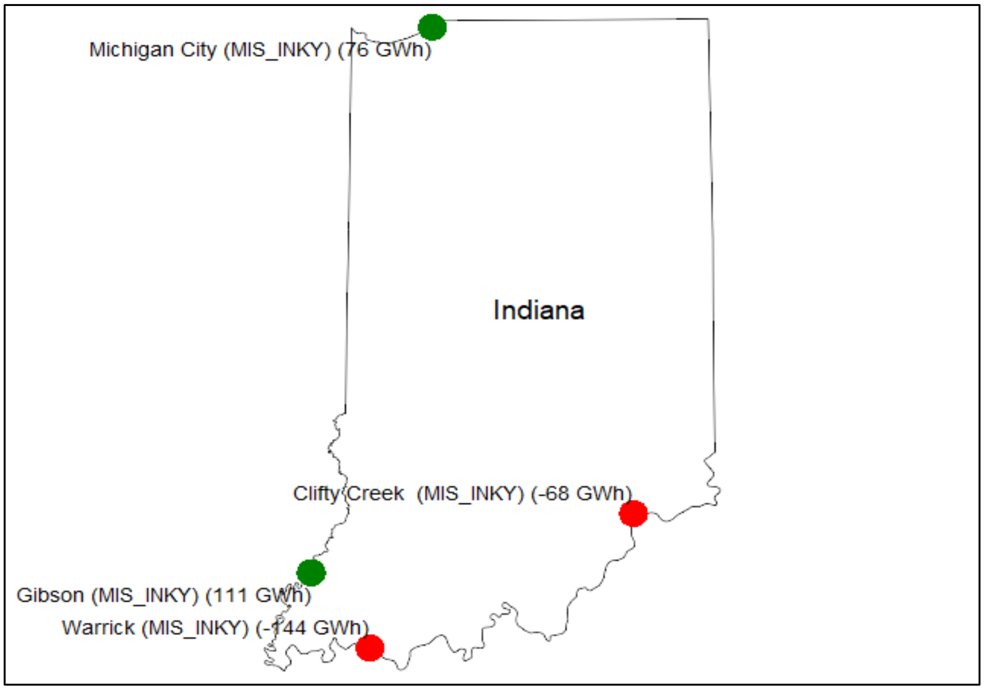
Appendix A presents maps for the nine states evaluated, depicting the stations that - per EPA's analysis - are most affected by generation shifting. These maps denote in "red" those generating stations (per EPA) projected to reduce generation, while those projected to increase generation are depicted in "green". The magnitude of generation shifted (in terms of GWh) for each station is numerically summarized in parenthesis. For simplicity, only the sources most significantly affected are displayed - thus the generation "decrease" vs. "increase" as shown on each map will not balance.

Details are discussed in respective state summaries in section 8 of draft report

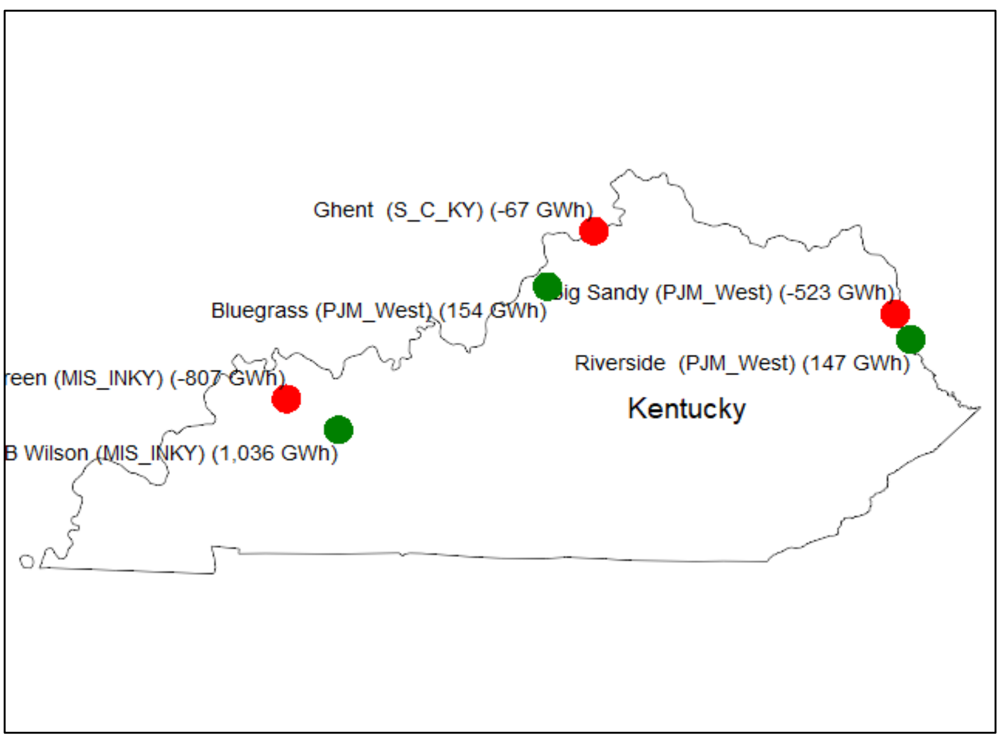
Arkansas: Major Generation Shifting Impact



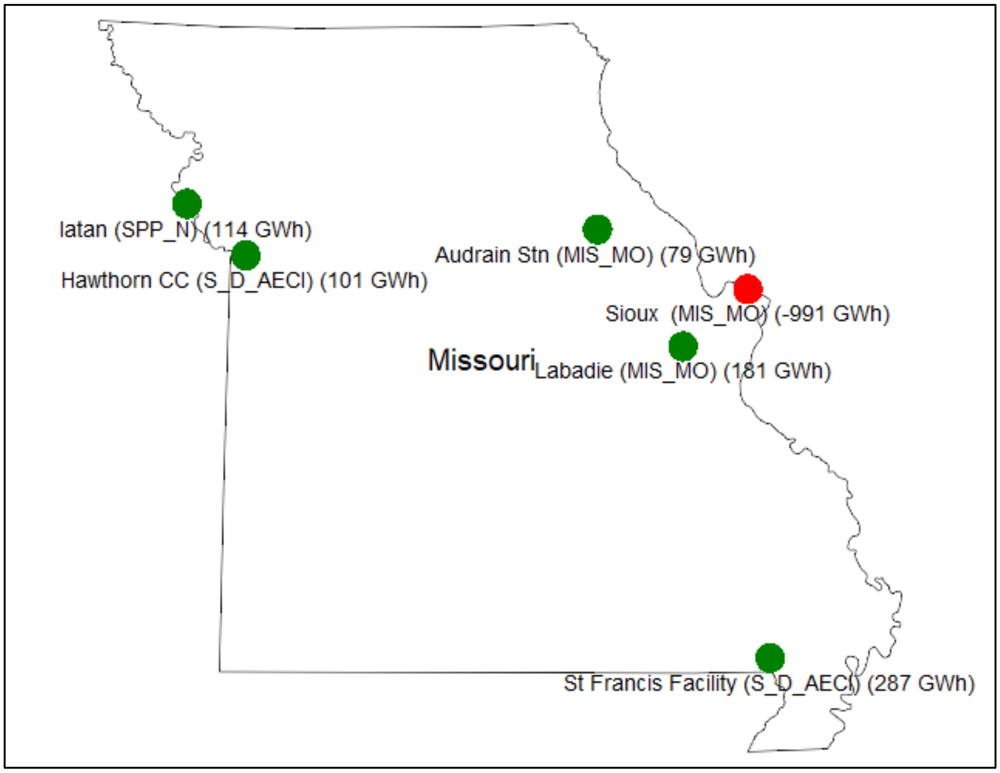
Indiana: Major Generation Shifting Impact



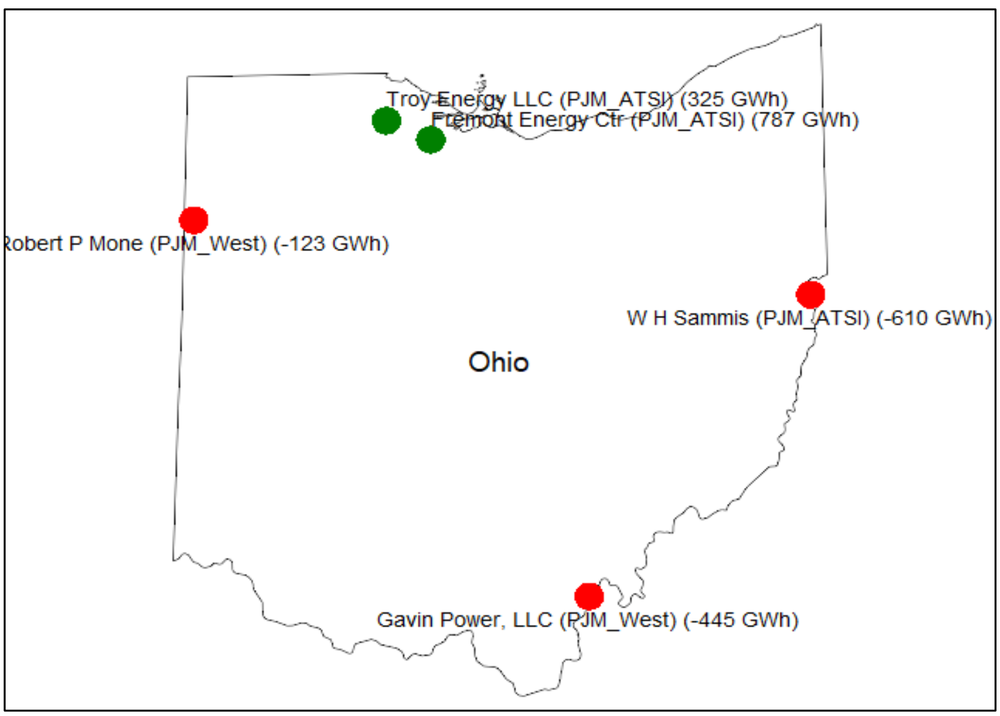
Kentucky: Major Generation Shifting Impact



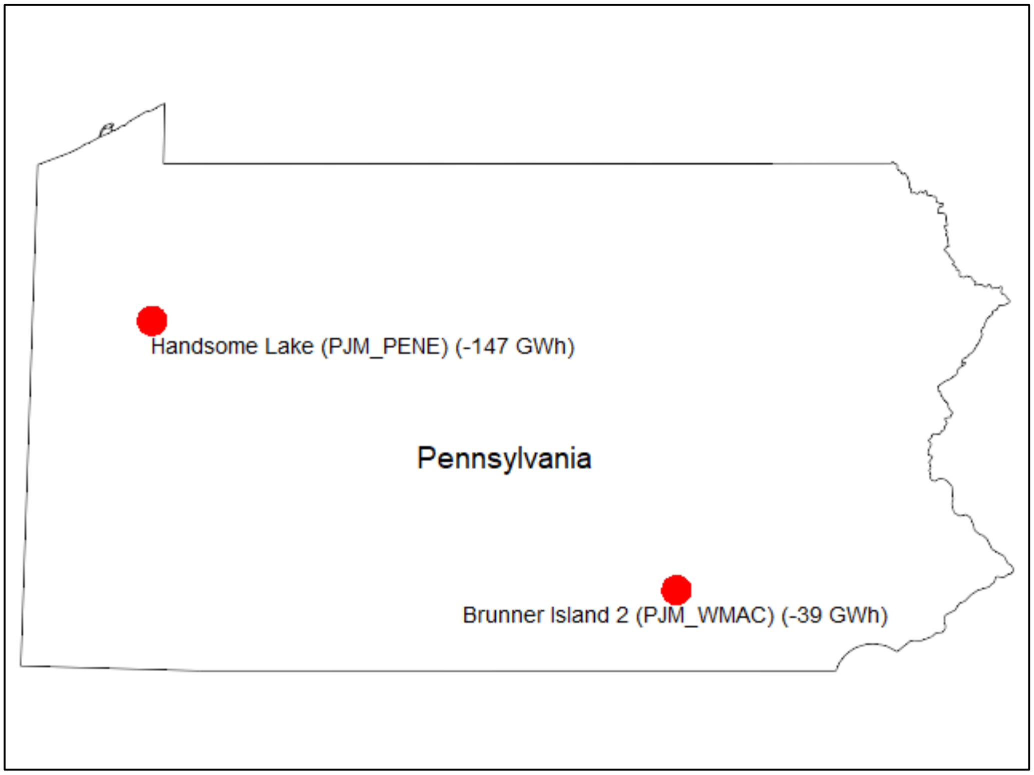
Missouri: Major Generation Shifting Impact



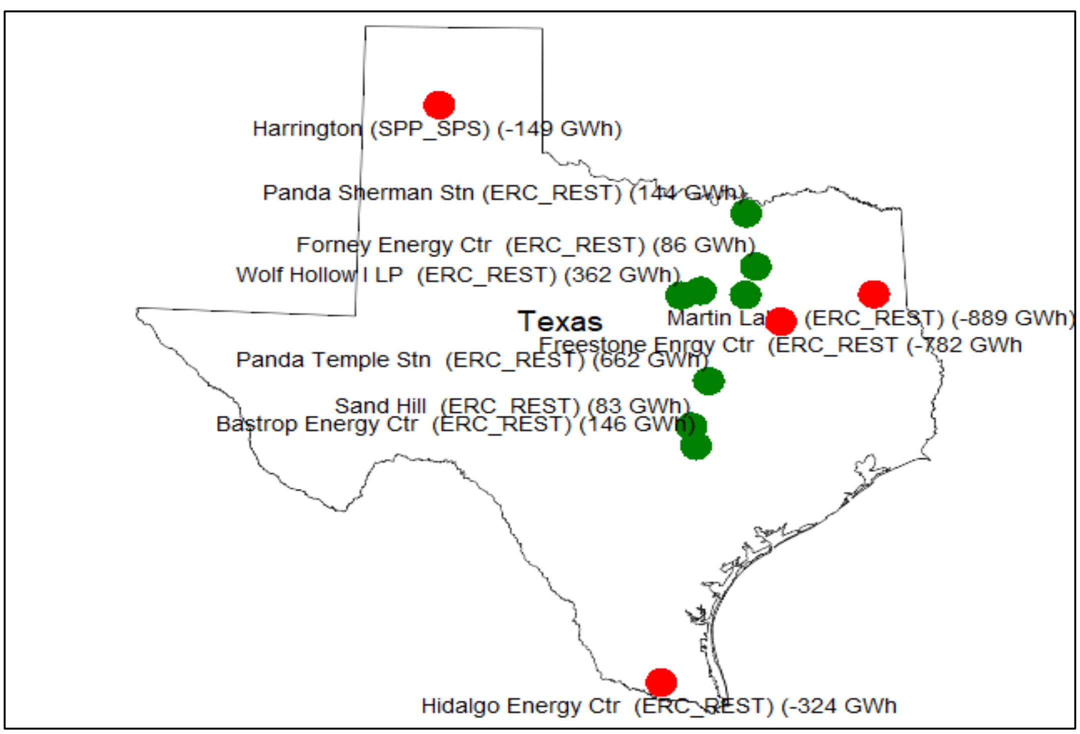
Ohio: Major Generation Shifting Impact



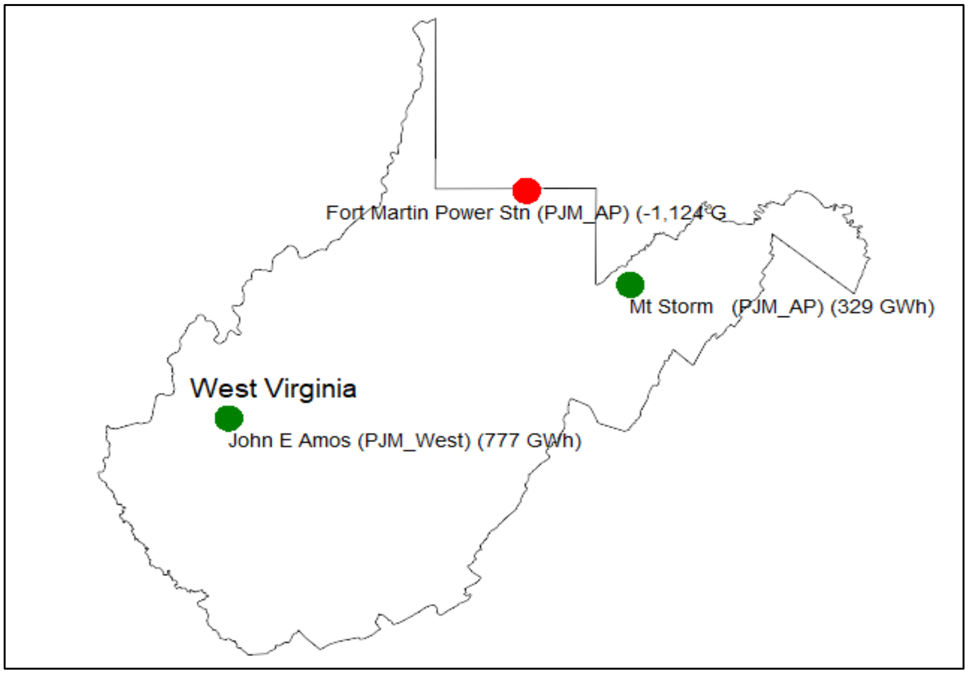
Pennsylvania: Major Generation Shifting Impact



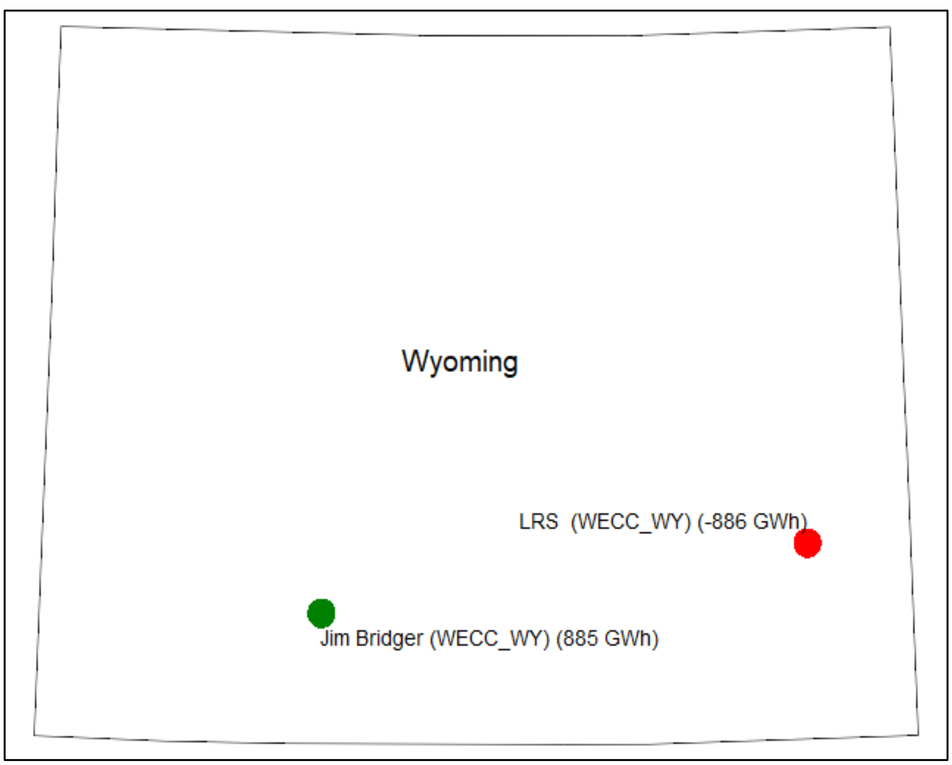
Texas: Major Generation Shifting Impact



West Virginia: Major Generation Shifting Impact



Wyoming: Major Generation Shifting Impact



Appendix B: Summary of Planned Retirements- 2026-2030

	OPERATOR	Authority (	STATE	LANT_ID	UNIT_NAME	GEN1	ewNMPLT	STATUS	Changes/Retirement	DATE	TECHNOLOGY
1	XCEL	MISO	MN	6090	SHERBURNE COUNTY 1	1	660	OPR	PSC approved closure (2/8/22). Upper Midwest Resource Plan (6/25/21) to retire unit in 2026 to be replaced by four smaller gas facilities	2026	Coal Steam SCR Retrofit
2	AEP PSO	SWPP	OK	2963	NORTHEASTERN 3	3	473	OPR	Retire 2026	2026	Coal Steam SCR Retrofit
3	VISTRA ENERGY (DYNEGY MIDWEST (IPH))	MISO	IL	6017	NEWTON 1	1	617.4	OPR	To be retired at the end of 2027 (9/29/20).	2027	Coal Steam SCR Retrofit
4	CLECO (merger with Macquarie)	MISO	LA	6190	RODEMACHER 2 (Brame Energy Center 2)	2	558	OPR	2020 IRP recommends LUS to consider retirement at the end of 2027.	2027	Coal Steam SCR Retrofit
5	SOUTHERN-MSPC	SERC	MS	6073	VJ DANIEL 2	2	548.3	OPR	MPC in its 2021 IRP will own 100 percent of one unit and retire it December 31, 2027.	2027	Coal Steam SCR Retrofit
6	VISTRA ENERGY (DYNEGY)	ERCO	TX	6178	COLETO CREEK 1	1	622.4	OPR	To be retired in 2027 due to economic pressure and environmental regulations.	2027	Coal Steam SCR Retrofit
7	PACIFICORP	WEST	WY	4158	DAVE JOHNSTON 1	1	133.6	OPR	retire in 2027.	2027	Coal Steam SCR Retrofit
8	PACIFICORP	WEST	WY	4158	DAVE JOHNSTON 2	2	133.6	OPR	retire in 2027.	2027	Coal Steam SCR Retrofit
9	PACIFICORP	WEST	WY	4158	DAVE JOHNSTON 3	3	255.0	OPR	retire in 2027.	2027	Coal Steam SCR Retrofit
10	PACIFICORP	WEST	WY	4158	DAVE JOHNSTON 4	4	400.0	OPR	retire in 2027.	2027	Coal Steam SCR Retrofit
11	SOUTHERN-ALPC	SERC	AL	3	BARRY 4	4	403.7	OPR	Order on HCl violation(1/3/22). Repowered to fire natural gas during peak loads by 2028 due to ELG.	2028	Coal Steam SCR Retrofit
12	ENTERGY	MISO	AR	6009	WHITE BLUFF 1	1	900	OPR	Both units cease burning coal as of 12/31/2028. Also reached an agreement with Sierra Club & NPCA on the same dates, which was	2028	Coal Steam SCR Retrofit
13	ENTERGY	MISO	AR	6009	WHITE BLUFF 2	2	900	OPR	Both units cease burning coal as of 12/31/2028. Also reached an agreement with Sierra Club & NPCA on the same dates, which was	2028	Coal Steam SCR Retrofit
14	LGE-KU(PP&L)	SERC	KY	1364	MILL CREEK (KY) 2	2	355.5	OPR	(11/25/20).	2028	Coal Steam SCR Retrofit
15	DTE ENERGY	MISO	MI	6034	BELLE RIVER 1	ST1	697.5	OPR	Announced the end of all coal use no later than December 2028, action complies with ELG (10/13/21).	2028	Coal Steam SCR Retrofit
16	DTE ENERGY	MISO	MI	6034	BELLE RIVER 2	ST2	697.5	OPR	Announced the end of all coal use no later than December 2028, action complies with ELG (10/13/21).	2028	Coal Steam SCR Retrofit
17	AMEREN-UE	MISO	MO	2107	SIOUX 1	1	549.7	OPR	2020 IRP - To be retired in 2028	2028	Coal Steam SCR Retrofit
18	AMEREN-UE	MISO	MO	2107	SIOUX 2	2	549.7	OPR	2020 IRP - To be retired in 2028	2028	Coal Steam SCR Retrofit
19	AEP - SWEPCO	SWPP	TX	6139	WELSH 1	1	558	OPR	June 2022 Investor Meetings - Retirement in 2028	2028	Coal Steam SCR Retrofit
20	AEP - SWEPCO	SWPP	TX	6139	WELSH 3	3	558	OPR	June 2022 Investor Meetings - Retirement in 2028	2028	Coal Steam SCR Retrofit
21	ENTERGY	MISO	AR	6641	INDEPENDENCE 1	1	900	OPR	Reached an agreement with Sierra Club and NPCA to cease burning coal by December 31, 2030, which was approved by a Federal judge on March	2030	Coal Steam SCR Retrofit
22	ENTERGY	MISO	AR	6641	INDEPENDENCE 2	2	900	OPR	Reached an agreement with Sierra Club and NPCA to cease burning coal by December 31, 2030, which was approved by a Federal judge on March	2030	Coal Steam SCR Retrofit
23	NRG	PJM	IL	879	POWERTON 5	5	892.8	OPR	Clean Engery Bill (SB2408) signed to close no later than January 1, 2030.	2030	Coal Steam SCR Retrofit
24	NRG	PJM	IL	879	POWERTON 6	6	892.8	OPR	Clean Engery Bill (SB2408) signed to close no later than January 1, 2030.	2030	Coal Steam SCR Retrofit
25	ENTERGY	MISO	LA	1393	RS NELSON 6	6	614.6	OPR	ENTERGY to retire all coal by 2030 (2/24/21).	2030	Coal Steam SCR Retrofit
26	XCEL	MISO	MN	6090	SHERBURNE COUNTY 3	3	809	OPR	to close in 2030	2030	Coal Steam SCR Retrofit
27	NRG ENERGY	ERCO	TX	298	LIMESTONE 1	1	893	OPR	2017	2030	Coal Steam SCR Retrofit
28	NRG ENERGY	ERCO	TX	298	LIMESTONE 2	2	813.4	OPR	2017	2030	Coal Steam SCR Retrofit
29	DESERT	WEST	UT	7790	BONANZA 1	1	499.5	OPR	consumption and installing new LNB/OFA. Could retire when the 20 million limit is reached.	2030	Coal Steam SCR Retrofit

Appendix II

APPA Summer 2021 Reference Case Analysis, James Marchetti, March 2021

OVERVIEW

EPA recently updated the NEEDS v6 for the Summer 2021 Reference Case (RC) and completed an IPM v6 Summer 2021 Reference Case run, which is an update of the January 2020 Reference Case. The intent of this file is to give APPA members the ability to evaluate how IPM modeled their individual fossil (coal and O/G) and nuclear units (>25 MW) during the run years 2023, 2025 and 2030 in the Summer 2021 Reference Case. The 2023 run year represents 2023, while the 2025 run represents the years 2024 to 2026 and the 2030 run year represents the years 2030 and 2031. It should be noted, for some combined cycle (CC) facilities the steam elements may be less than 25 MW, but were included because the combustion turbine (CT) is greater than 25 MW. The updated Power Sector Modeling Platform v6 for the Summer 2021 Reference Case can be found on EPA's CAMD web site below:

EPA's Power Sector Modeling Platform v6 using IPM Summer 2021 Reference Case | US EPA

The updated NEEDS v6 for the Summer 2021 Reference Case reflects comments accepted by EPA for the March 2021 NEEDS Update (needs v620_3-31-21) plus EPA/ICF research through March 2021. The IPM v6 Summer 2021 Reference Case reflects the latest data and regulations affecting the power sector, and they include:

- New Cost and Performance Assumptions for Fossil and Renewable Technologies
- Updated Gas and Coal Market Assumptions through September 2020
- Updates of Nuclear Unit Operational Assumptions from AEO 2020
- Financial Assumptions reflecting Tax Credit Extensions from Consolidated Appropriations Act of 2021
- Updated Transmission data
- CCS Retrofits on CC units
- Greater Detail on Operating Reserves

It should be noted that the Summer 2021 Reference Case used AEO 2020 for future electrical demand, which projected annual net power generation to grow 0.865% annually between 2019 and 2050.

The v6 Summer 2021 Reference Case takes into account compliance with various regulations, which are summarized below:

- Revised Cross-State Air Pollution Rule (CSAPR) Update Rule
- Standards of Performance for Greenhous Gas Emissions from New, Modified and Reconstructed Stationary Sources: electric Utility Generating Units
- MATS Rule which was finalized in 2011
- Various current and existing state regulations
- Current and existing RPS and Current Energy Standards
- Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART)
- Platform reflects California AB 32 and RGGI
- Three non-air federal rules affecting EGUs: (i) Cooling Water Intakes (316(b) Rule; (ii) Coal Combustion Residuals (CCR), which reflects EPA's July 29, 2020 position on retrofitting or closure of surface impoundments; and, (iii) Effluent Limitation Guidelines, which includes the 2020 Steam Electric Reconsideration Rule (cost adders were applied starting in 2025).

The Affordable Clean Energy (ACE) was modeled in the January 2020 Reference Case, but was removed in the Summer 2021 Reference Case.

The file is comprised of seven tabs and they are as follows:

Tab 1: Summer_2021_RC – This tab summarizes IPM modeled unit operations for the run years 2023, 2025 and 2030 for the Summer 2021 Reference Case, which include IPM modeled retrofits/retirements and computed capacity factors (CF), heat rates and emission rates for all Public Power coal, O/G and nuclear units. The 2023 run year is highlighted in **black**. The 2025 run year is highlighted in **red** and the 2030 run year is highlighted in **blue.**

Tab 2: Summer_2021_RC_2023 – This tab is an IPM parsed file, which illustrates how IPM modeled Public Power coal, O/G and nuclear units in 2023 in the IPM v6 Summer 2021 Reference Case. It shows on an individual unit basis, existing design information, any modeled retrofits/retirements, 2023 fuel use, generation and emissions. (See the attached *Parsed File User Guide*, which explains each column of the file). Those columns highlighted in yellow are not a part of 2023 parsed file, but were added to provide a more illustration on how IPM modeled specific Public Power units in 2023. More specifically, Column W illustrates whether IPM modeled a retrofit or retirement in 2023, which is the first modeled year in in the IPM v6 Summer 2021 Reference Case. Columns CB to CH provide 2023 calculated capacity factors, heat rates and emission rates for each Public Power unit operating in 2023.

Tab 3: Summer_2021_RC_2025 – This tab is an IPM parsed file, which illustrates how IPM modeled Public Power coal, O/G and nuclear units in 2025 in the IPM v6 Summer 2021 Reference Case. It is in the similar format as *Tab 4: Summer_2021_RC_2023.*

Tab 4: Summer_2021_RC_2025 – This tab is an IPM parsed file, which illustrates how IPM modeled Public Power coal, O/G and nuclear units in 2030 in the IPM v6 Summer 2021 Reference Case. It is in the similar format as *Tab 4: Summer_2021_RC_2023.*

Tab 5: NEEDS_Retirements_2023 – Lists announced Public Power EGUs that EPA believes have or will be retired between 2020 and 2023 from the NEEDS file. The Comments have been added by James Marchetti.

Tab 6: IPM Modeled Ret_Conversions – Lists those Public Power units that IPM retired or converted in the Summer 2021 Reference Case. The Comments have been added by James Marchetti.

Tab 7: IPM_Idled_Coal_Capacity – Lists those Public Power coal units that IPM idled in the Summer 2021 Reference Case by run year.

Overview of the Summer 2021 Reference Case

The table below illustrates the number of Public Power Fossil and Nuclear units modeled by IPM in the Summer 2021 Reference Case for the run years 2023, 2025 and 2030 and their operating capacities. The changes in capacity from one run year to the next represent retirements or conversions modeled by IPM. More specifically, IPM handled 733 Public Power Fossil and Nuclear units and determined (modelled) the operating capacities, as listed below. The IPM operating capacities represent those units that are operating minus any retirements. Also, the operating capacities represent the total capacity of all Public Power wholly and jointly-owned units; meaning Public Power ownership shares were not applied to a jointly owned unit's total capacity. These retirements/conversions will be discussed in more detail in **Retirements/Idling**

Year	No. Units	Public Power Total Operating Capacity (MW)	Public Power Operating Coal (MW)	Public Power Operating Nuclear (MW)	Public Power Operating Gas (MW)
2023	733	127,298	47,685	28,525	51,087
2025	733	125,180	46,000	27,756	51,413
2030	733	120,003	41,843	25,284	52,877

As you can see from the table above, IPM has coal representing slightly more than one-third of Public Power's operating capacity, while nuclear is about 22 percent and natural gas slightly greater than 40 percent of Public Power's modeled operating capacity.

Looking more specifically at how IPM modeled Public Power coal capacity, which always tends to be an issue in IPM modeling. The table below shows the level of IPM Public Power operating coal capacity, amount of Public Power coal capacity idled by IPM in a run year, cumulative coal retirements modeled by IPM and IPM modeled coal to gas (C2G) conversions.

Year	No. Units	Public Power Operating Coal (MW)	Public Power Operating Coal Idled (MW)	Public Power Coal Retirements (MW)	Public Power C2G (MW)
2023	124	47,685	10,558	7,531	0
2025	124	46,000	9,712	8,749	336
2030	124	41,843	5,700	11,060	1,973

As you can see from the table above IPM idles over 20 percent of Public Power operating coal capacity in the 2023 and 2025 run years. The level of idled capacity drops in 2030, due to the increase in demand which is not able to be met by other types of generating resources. In terms of coal retirements, IPM models increasing coal retirements through 2030; whereby, 2030 the level of coal retirements would be equal to a quarter of Public Power's modeled operating coal capacity.

Retirements/Idling

Prior to the modeling the first run year (2023) in the Summer 2021 Reference Case, EPA removes announced retirements through 2023 from the simulation as shown in Tab 5. These retirements seem to begin in 2020 and run through 2023. IPM has removed 2,397 MW of Public Power coal capacity and 581 MW of gas capacity prior to the modeling. However, there are several coal units not listed in the NEEDS file that have or will be retired between 2020 and 2023, some of which their retirements may have announced after the modeling was initiated; thereby, may appear in the 2023 modeling run and they are:

- Dolet Hills retired in 2021, modeled as a retirement in 2023
- McIntosh 3 retired in 2021, modeled as a retirement in 2023
- Muscatine 8 planned retirement in 2023, modeled as operating in 2023
- Dallman 3 retired in 2021, modeled as operating in 2023
- Dolet Hills retired in 2021, modeled as a retirement in 2023
- Scherer 4 planned retirement in 2022, modeled as a retirement in 2023
- Wansley 1 & 2 planned retirement in 2022, modeled as a retirement in 2023
- Winyah 3 & 4 planned retirement in 2023, modeled as operating in 2023
- Bull Run planned retirement in 2023, modeled as a retirement in 2023

In addition to the above coal units, San Juan 4 which is to be retired in 2022 can't be found in the parsed files.

2023 Simulation

In the Summer 2021 Reference Case 2023 simulation IPM retired 23 coal units, some are discussed above, representing 7,531 MW of coal capacity, in which Public Power has an interest, as shown in Tab 6. In IPM, the regional capacity price ($/kW) and the unit Fixed O&M (FOM) cost ($/kW) are going to affect whether it decides to retire a unit. The S_C_TVA and S_SOU IPM subregions accounted for almost 72 percent (5,418 MW) of this retired coal capacity. In addition to coal, IPM retired 4 Public Power O/G steam units totaling 252 MW and the J. Robert Massengale CC facility in 2023.

However, the most significant modeling result of the Summer 2021 Reference Case 2023 simulation is the idling of 22 Public Power coal units representing 10,558 MW of capacity in 2023 (see Tab 7). This idled coal capacity accounts for 22.1 percent to the total operating coal capacity that IPM has assigned to Public Power in 2023. The ERC_Rest IPM subregion accounts for almost 45 percent of this idled coal capacity. One interesting plant that is idled is the JT Deely units. The CPS Energy's *2021 Flexible Path Resource Plan* indicates the plant was retired December 31,2018; however, it is still generating electricity for internal use.

2025 Simulation

In the Summer 2021 Reference Case 2025 simulation IPM retires four additional Public Power coal units totaling an additional 1,218 MW. Three of these units (Fayette 3, Spruce 1 and Whitewater Valley 1) were idled in 2023 simulation. There are no additional natural gas retirements, but IPM does model a natural gas conversion of North Omaha 4 & 5 in 2025. North Omaha is converted, but is idled in both the 2025 and 2030 run years. IPM also retires the Cooper Nuclear Station in 2025.

In the 2025 simulation IPM continues to idle 20 Public Power coal units representing 9,712 MW of coal capacity, which accounts for 21 percent of the IPM modeled operating coal capacity. The level of idled capacity decreased due to units being brought back into service or being retired. Similar to 2023, the ERC_Rest IPM subregion has the greatest concentration of idled coal capacity

2030 Simulation

The Summer 2021 Reference Case 2030 simulation IPM does retire three additional Public Power coal units totaling an additional 2,311 MW. There are no additional gas units retired, but IPM does retire two additional nuclear units, which Public Power has interests (Millstone 3 and Seabrook). In addition to these retirements, IPM converts White Bluff 1 & 2 to natural gas in 2030.

In the Summer 2021 Reference Case 2030 simulation IPM reduces the number of coal units idled to 12 (5,700 MW). This decrease in idled coal capacity from the 2025 simulation is a result of the need to bring on-line idled coal units to meet 2030 demand.

Additional Discussion on Idling

In the Summer 2021 Reference Case units can either be idled during the entire three run years (2023, 2025 and 2030) or brought on-line in a specific run year to meet demand, such as 2030. For example, those units that remained idled during the three run years, either regional generation was projected to decrease or regional generation does increase but the additional generation is picked-up the new resources. For example, in ERC_Rest, between 2023 and 2025 IPM projects a 464 percent increase in new On-Shore Wind which depresses both coal and natural gas generation. On the other hand, for those idled units that were brought on-line in 2030, regional generation is projected to increase substantially between 2025 and 2030 and all non-coal sources were at their maximum generation levels. For example, in S_Sou, no new capacity came on-line in 2030, resulting in Scherer 1 & 2 being brought on-line to meet regional demand.

In IPM, a unit can be idled but not retired if its FOM costs ($/kW) is less than the annualized capital cost ($/kW) to build a new combined cycle unit. IPM will bring a unit back on-line if its variable cost (VOM and Fuel) is less than the regional segmental energy price for a specific run year.

Technology Retrofits

The only major technology retrofit modeled by IPM in the Summer 2021 Reference Case is the deployment of CCS on Laramie River 1 in 2025 and Four Corners 4 & 5 in 2030. The Four Corners seems to be designated for retirement in 2031. In addition to the coal units IPM deployed CCS on three natural gas combined cycle plants in California – Consume, Haynes and Valley in 2030.

The 45Q tax credit was modeled by IPM in the Reference Cases. The 45Q tax credit is implemented by applying the value of the credit through an adjustment to the step prices in the CO_2 storage cost curves. The process involves converting the dollar amounts of credit into 2019 real dollars, calculating weighted average tax credits by run year, and applying the weighted average tax credits to the individual step prices in the CO_2 storage cost curves

The deployment of CCS on Laramie River 1 resulted in a capacity derating from 570 MW to 439 MW and increase in the unit's heat rate from 10,218 Btu/kWh to around 13,500 Btu/kWh. Based upon the change in CO_2 emission rate, it seems the CCS on Laramie River 1 would remove about 73 percent of the unit's CO_2. In terms of Four Corners, Unit 4's heat rate increased from 9,771 Btu/kWh to 12,143 Btu/kWh and based upon the change in CO_2 emission rate results in 87.6 percent reduction. Unit 5's heat rate increased from 9,776 Btu/kWh to 11,013 Btu/kWh, but the CO_2 reduction only see to be 56.1 percent.