Case No. ______

In the Supreme Court of the United States

UNITED STATES STEEL CORPORATION,

Applicant,

v.

ENVIRONMENTAL PROTECTION AGENCY AND MICHAEL S. REGAN, ADMINISTRATOR,

Respondents.

On Application for Stay to the Honorable John G. Roberts, Jr., Chief Justice and Circuit Justice for the District of Columbia Circuit

APPENDIX TO EMERGENCY APPLICATION FOR STAY OF FINAL AGENCY ACTION PENDING JUDICIAL REVIEW

October 26, 2023

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 52, 75, 78, and 97

[EPA–HQ–OAR–2021–0668; FRL–8670–02–OAR]

RIN 2060–AV51

Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes Federal Implementation Plan (FIP) requirements to address 23 states' obligations to eliminate significant contribution to nonattainment, or interference with maintenance, of the 2015 ozone National Ambient Air Quality Standards (NAAQS) in other states. The U.S. Environmental Protection Agency (EPA) is taking this action under the ''good neighbor'' or ''interstate transport'' provision of the Clean Air Act (CAA or Act). The Agency is defining the amount of ozone-precursor emissions (specifically, nitrogen oxides) that constitute significant contribution to nonattainment and interference with maintenance from these 23 states. With respect to fossil fuel-fired power plants in 22 states, this action will prohibit those emissions by implementing an allowance-based trading program beginning in the 2023 ozone season. With respect to certain other industrial stationary sources in 20 states, this action will prohibit those emissions through emissions limitations and associated requirements beginning in the 2026 ozone season. These industrial source types are: reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; kilns in Cement and Cement Product Manufacturing; reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and combustors and incinerators in Solid Waste Combustors and Incinerators.

DATES: This final rule is effective on August 4, 2023.

ADDRESSES: The EPA has established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2021–0668. All documents in the docket are listed in the *https://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically at *https://www.regulations.gov* or in hard copy at the U.S. Environmental Protection Agency, EPA Docket Center, William Jefferson Clinton West Building, Room 3334, 1301 Constitution Ave. NW, Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Office of Air and Radiation Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Elizabeth Selbst, Air Quality Policy Division, Office of Air Quality Planning and Standards (C539–01), Environmental Protection Agency, 109 TW Alexander Drive, Research Triangle Park, NC 27711; telephone number: (312) 886–4746; email address: *selbst.elizabeth@epa.gov.*

SUPPLEMENTARY INFORMATION:

Preamble Glossary of Terms and Abbreviations

The following are abbreviations of terms used in the preamble.

2016v1 2016 Version 1 Emissions Modeling Platform
2016v2 2016 Version 2 Emissions Modeling Platform
4-Step Framework 4-Step Interstate Transport Framework
ABC Associated Builders and Contractors
ACS American Community Survey
ACT Alternative Control Techniques
AEO Annual Energy Outlook
AQAT Air Quality Assessment Tool
AQS Air Quality System
BACT Best Available Control Technology
BART Best Available Retrofit Technology
BOF Basic Oxygen Furnace
BPT Benefit Per Ton
C1C2 Category 1 and Category 2
C3 Category 3
CAA or Act Clean Air Act
CAIR Clean Air Interstate Rule
CBI Confidential Business Information
CCR Coal Combustion Residual
CDC Centers for Disease Control and Prevention
CDX Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CEMS Continuous Emissions Monitoring Systems
CES Clean Energy Standards
CFB Circulating Fluidized Bed Units
CHP Combined Heat and Power
CMDB Control Measures Database
CMV Commercial Marine Vehicle
CoST Control Strategy Tool
CPT Cost Per Ton
CRA Congressional Review Act
CSAPR Cross-State Air Pollution Rule
DAHS Data Acquisition and Handling System
DOE Department of Energy
EAF Electric Arc Furnace
EGU Electric Generating Unit
EIA U.S. Energy Information Agency
EIS Emissions Inventory System
EISA Energy Independence and Security Act
ELG Effluent Limitation Guidelines
E.O. Executive Order
EPA or the Agency United States Environmental Protection Agency
ERT Electronic Reporting Tool
FERC Federal Energy Regulatory Commission
FFS Findings of Failure to Submit
FIP Federal Implementation Plan
GIS Geographic Information System
g/hp-hr grams per horsepower per hour
HDGHG Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles
HEDD High Electricity Demand Days
ICI Industrial, Commercial, and Institutional
I/M Inspection and Maintenance
IPM Integrated Planning Model
IRA Inflation Reduction Act
LAER Lowest Achievable Emission Rate
LDC Local Distribution Company
LME Low Mass Emissions
LNB Low-NO_X Burners
MATS Mercury and Air Toxics Standards
MCM Menu of Control Measures
MDA8 Maximum Daily Average 8-Hour
MJO Multi-Jurisdictional Organization
MOU Memorandum of Understanding
MOVES Motor Vehicle Emissions Simulator
MSAT2 Mobile Source Air Toxics Rule
MWC Municipal Waste Combustor
NAAQS National Ambient Air Quality Standards
NACAA National Association of Clean Air Agencies
NAICS North American Industry Classification System
NEEDS National Electric Energy Data System
NEI National Emissions Inventory
NERC North American Electric Reliability Corporation
NESHAP National Emissions Standards for Hazardous Air Pollutants
NMB Normalized Mean Bias
NME Normalized Mean Error
No SISNOSE No Significant Economic Impact on a Substantial Number of Small Entities
Non-EGU Non-Electric Generating Unit
NODA Notice of Data Availability
NO_X Nitrogen Oxides
NREL National Renewable Energy Lab
NSCR Non-Selective Catalytic Reduction
NSPS New Source Performance Standard
NSR New Source Review
NTTAA National Technology Transfer and Advancement Act
OFA Over-Fire Air
OMB United States Office of Management and Budget

OSAT/APCA Ozone Source Apportionment Technology/Anthropogenic Precursor Culpability Analysis
OTC Ozone Transport Commission
OTR Ozone Transport Region
OTSA Oklahoma Tribal Statistical Area
PDF Portable Document Format
PEMS Predictive Emissions Monitoring Systems
$PM_{2.5}$ Fine Particulate Matter
ppb parts per billion
ppm parts per million
ppmv parts per million by volume
ppmvd parts per million by volume, dry
PRA Paperwork Reduction Act
PSD Prevention of Significant Deterioration
PTE Potential to Emit
RACT Reasonably Available Control Technology
RATA Relative Accuracy Test Audit
RCF Relative Contribution Factor
RFA Regulatory Flexibility Act
RICE Reciprocating Internal Combustion Engines
ROP Rate of Progress
RPS Renewable Portfolio Standards
RRF Relative Response Factor
RTC Response to Comments
RTO Regional Transmission Organization
SAFETEA Safe, Accountable, Flexible, Efficient, Transportation Equity Act
SCC Source Classification Code
SCR Selective Catalytic Reduction
SIL Significant Impact Level
SIP State Implementation Plan
SMOKE Sparse Matrix Operator Kernel Emissions
SNCR Selective Non-Catalytic Reduction
SO_2 Sulfur Dioxide
tpd ton per day
TAS Treatment as State
TSD Technical Support Document
UMRA Unfunded Mandates Reform Act
VMT Vehicle Miles Traveled
VOCs Volatile Organic Compounds
WRAP Western Regional Air Partnership
WRF Weather Research and Forecasting

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I. Executive Summary

This final rule resolves the interstate transport obligations of 23 states under CAA section 110(a)(2)(D)(i)(I), referred to as the ''good neighbor provision'' or the ''interstate transport provision'' of the Act, for the 2015 ozone NAAQS. On October 1, 2015, the EPA revised the primary and secondary 8-hour standards for ozone to 70 parts per billion (ppb).[1] States were required to submit to EPA ozone infrastructure State Implementation Plan (SIP) revisions to fulfill interstate transport obligations for the 2015 ozone NAAQS by October 1, 2018. The EPA proposed the subject rule to address outstanding interstate ozone transport obligations for the 2015 ozone NAAQS in the **Federal Register** on April 6, 2022 (87 FR 20036).

The EPA is making a finding that interstate transport of ozone precursor emissions from 23 upwind states (Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin) is significantly contributing to nonattainment or interfering with maintenance of the 2015 ozone NAAQS in downwind states, based on projected ozone precursor emissions in the 2023 ozone season. The EPA is issuing FIP requirements to eliminate interstate transport of ozone precursor emissions from these 23 states that significantly contributes to nonattainment or interferes with maintenance of the NAAQS in downwind states. The EPA is not finalizing its proposed error correction for Delaware's ozone transport SIP, and we are deferring final action at this time on the proposed FIPs for Tennessee and Wyoming pending further review of the updated air quality and contribution modeling and analysis developed for this final action. As discussed in section III of this document, the EPA's updated analysis of 2023 suggests that the states of Arizona, Iowa, Kansas, and New Mexico may be significantly contributing to one or more nonattainment or maintenance receptors. The EPA is not making any final determinations with respect to these states in this action but intends to address these states, along with Tennessee and Wyoming, in a subsequent action or actions.

The EPA is finalizing FIP requirements for 21 states for which the Agency has, in a separate action, disapproved (or partially disapproved) ozone transport SIP revisions that were submitted for the 2015 ozone NAAQS: Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Texas, Utah, West Virginia, and Wisconsin. *See* 88 FR 9336. In this final rule, the EPA is issuing FIPs for two states—Pennsylvania and Virginia—for which the EPA issued Findings of Failure to Submit for 2015 ozone NAAQS transport SIPs. *See* 84 FR 66612 (December 5, 2019). Under CAA section 301(d)(4), the EPA is extending FIP requirements to apply in Indian country located within the upwind geography of the final rule, including Indian reservation lands and other areas of Indian country over which the EPA or a tribe has demonstrated that a tribe has jurisdiction.[2]

This final rule defines ozone season nitrogen oxides (NO_X) emissions

[1] *See* 80 FR 65291 (October 26, 2015).

[2] In general, specific tribal names or reservations are not identified separately in this final rule except as needed. *See* section III.C.2 of this document for further discussion about the application of this rule in Indian Country.

performance obligations for Electric Generating Unit (EGU) sources and fulfills those obligations by implementing an allowance-based ozone season trading program beginning in 2023. This rule also establishes emissions limitations beginning in 2026 for certain other industrial stationary sources (referred to generally as ''non-Electric Generating Units'' (non-EGUs)). Taken together, these regulatory requirements will fully eliminate the amount of emissions that constitute the covered states' significant contribution to nonattainment and interference with maintenance in downwind states for purposes of the 2015 ozone NAAQS.

This final rule implements the necessary emissions reductions as follows. Under the FIP requirements, EGUs in 22 states (Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin) are required to participate in a revised version of the Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 3 Trading Program that was previously established in the Revised CSAPR Update.[3] In addition to reflecting emissions reductions based on the Agency's determination of the necessary control stringency in this rule, the revised trading program includes several enhancements to the program's design to better ensure achievement of the selected control stringency on all days of the ozone season and over time. For 12 states already required to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program (Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia) under the Revised CSAPR Update (with respect to the 2008 ozone NAAQS), the FIPs are amended by the revisions to the Group 3 trading program regulations. For seven states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program under SIPs or FIPs, the EPA is issuing new FIPs for two states (Alabama and Missouri) and amending existing FIPs for five states (Arkansas, Mississippi, Oklahoma, Texas, and Wisconsin) to transition EGU sources in these states from the Group 2 program to the revised Group 3 trading program, beginning with the 2023 ozone season. The EPA is issuing new FIPs for three states not currently covered by any CSAPR NO_X ozone season trading program: Minnesota, Nevada, and Utah.

This rulemaking requires emissions reductions in the selected control stringency to be achieved as expeditiously as practicable and, to the extent possible, by the next applicable nonattainment dates for downwind areas for the 2015 ozone NAAQS. Thus, initial emissions reductions from EGUs will be required beginning in the 2023 ozone season and prior to the August 3, 2024, attainment date for areas classified as Moderate nonattainment for the 2015 ozone NAAQS.

The remaining emissions reduction obligations will be phased in as soon as possible thereafter. Substantial additional reductions from potential new post-combustion control installations at EGUs as well as from installation of new pollution controls at non-EGUs, also referred to in this action as industrial sources, will phase in beginning in the 2026 ozone season, associated with the August 3, 2027, attainment date for areas classified as Serious nonattainment for the 2015 ozone NAAQS. The EPA had proposed to require all emissions reductions to eliminate significant contribution to be in place by the 2026 ozone season. While we continue to view 2026 as the appropriate analytic year for purposes of applying the 4-step interstate transport framework, as discussed in section V.D.4 and VI.A.2 of this document, the final rule will allow individual facilities limited additional time to fully implement the required emissions reductions where the owner or operator demonstrates to the EPA's satisfaction that more rapid compliance is not possible. For EGUs, the emissions trading program budget stringency associated with retrofit of post-combustion controls will be phased in over two ozone seasons (2026–2027). For industrial sources, this final rule provides a process for individual facilities to seek a one year extension, with the possibility of up to two additional years, based on a specific showing of necessity.

The EGU emissions reductions are based on the feasibility of control installation for EGUs in 19 states that remain linked to downwind nonattainment and maintenance receptors in 2026. These 19 states are: Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. The emissions reductions required for EGUs in these states are based primarily on the potential retrofit of additional post-combustion controls for NO_X on most coal-fired EGUs and a portion of oil/gas-fired EGUs that are currently lacking such controls.

The EPA is finalizing, with some modifications from proposal in response to comments, certain additional features in the allowance-based trading program approach for EGUs, including dynamic adjustments of the emissions budgets and recalibration of the allowance bank over time as well as backstop daily emissions rate limits for large coal-fired units. The purpose of these enhancements is to better ensure that the emissions control stringency the EPA found necessary to eliminate significant contribution at Step 3 of the 4-step interstate transport framework is maintained over time in Step 4 implementation and is durable to changes in the power sector. These enhancements ensure the elimination of significant contribution is maintained both in terms of geographical distribution (by limiting the degree to which individual sources can avoid making emissions reductions) and in terms of temporal distribution (by better ensuring emissions reductions are maintained throughout each ozone season, year over year). As we further discuss in section V.D of this document, these changes do not alter the stringency of the emissions trading program over time. Rather, they ensure that the trading program (as the method of implementation at Step 4) remains aligned with the determinations made at Step 3. These enhancements are further discussed in section VI.B of this document.

The EPA is making a finding that NO_X emissions from certain non-EGU sources are significantly contributing to nonattainment or interfering with maintenance of the 2015 ozone NAAQS and that cost-effective controls for NO_X emissions reductions are available in certain industrial source categories that would result in meaningful air quality improvements in downwind receptors. The EPA is establishing emissions limitations beginning in 2026 for non-EGU sources located within 20 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. The final rule establishes NO_X emissions limitations during the ozone season for the following unit types for sources in

[3] As explained in section V.C.1 of this document, the EPA is making a finding that EGU sources within the State of California are sufficiently controlled such that no further emissions reductions are needed from them to eliminate significant contribution to downwind states.

non-EGU industries:[4] reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; kilns in Cement and Cement Product Manufacturing; reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and combustors and incinerators in Solid Waste Combustors and Incinerators.

A. Purpose of the Regulatory Action

The purpose of this rulemaking is to protect public health and the environment by reducing interstate transport of certain air pollutants that significantly contribute to nonattainment, or interfere with maintenance, of the 2015 ozone NAAQS in downwind states. Ground-level ozone has detrimental effects on human health as well as vegetation and ecosystems. Acute and chronic exposure to ozone in humans is associated with premature mortality and certain morbidity effects, such as asthma exacerbation. Ozone exposure can also negatively impact ecosystems by limiting tree growth, causing foliar injury, and changing ecosystem community composition. Section III of this document provides additional evidence of the harmful effects of ozone exposure on human health and the environment. Studies have established that ozone air pollution can be transported over hundreds of miles, with elevated ground-level ozone concentrations occurring in rural and metropolitan areas.[5,6] Assessments of ozone control approaches have concluded that control strategies targeting reduction of NO_X emissions are an effective method to reduce regional-scale ozone transport.[7]

CAA section 110(a)(2)(D)(i)(I) requires states to prohibit emissions that will contribute significantly to nonattainment or interfere with maintenance in any other state with respect to any primary or secondary NAAQS.[8] Within 3 years of the EPA promulgating a new or revised NAAQS, all states are required to provide SIP submittals, often referred to as ''infrastructure SIPs,'' addressing certain requirements, including the good neighbor provision. *See* CAA section 110(a)(1) and (2). The EPA must either approve or disapprove such submittals or make a finding that a state has failed to submit a complete SIP revision. As with any other type of SIP under the Act, when the EPA disapproves an interstate transport SIP or finds that a state failed to submit an interstate transport SIP, the CAA requires the EPA to issue a FIP to directly implement the measures necessary to eliminate significant contribution under the good neighbor provision. *See generally* CAA section 110(k) and 110(c). As such, in this rule, the EPA is finalizing requirements to fully address good neighbor obligations for the covered states for the 2015 ozone NAAQS under its authority to promulgate FIPs under CAA section 110(c). By eliminating significant contribution from these upwind states, this rule will make substantial and meaningful improvements in air quality by reducing ozone levels at the identified downwind receptors as well as many other areas of the country. At any time after the effective date of this rule, states may submit a Good Neighbor SIP to replace the FIP requirements contained in this rule, subject to EPA approval under CAA section 110(a).

The EPA conducted air quality modeling for the 2023 and 2026 analytic years to identify (1) the downwind areas identified as ''receptors'' (which are associated with monitoring sites) that are expected to have trouble attaining or maintaining the 2015 ozone NAAQS in the future and (2) the contribution of ozone transport from upwind states to the downwind air quality problems. We use the term ''downwind'' to describe those states or areas where a receptor is located, and we use the term ''upwind'' to describe states whose emissions are linked to one or more receptors. States may be both downwind and upwind depending on the receptor or linkage in question. Section IV of this document provides a full description of the results of the EPA's updated air quality modeling and relevant analyses for the rulemaking, including a discussion of how updates to the modeling and air quality analysis following the proposed rule have resulted in some modest changes in the overall geography of the final rule. Based on the EPA's air quality analysis, the 23 upwind states covered in this action are linked above the 1 percent of the NAAQS threshold to downwind air quality problems in downwind states. The EPA intends to expeditiously review the updated air quality modeling and related analyses to address potential good neighbor requirements of six additional states—Arizona, Iowa, Kansas, New Mexico, Tennessee, and Wyoming—in a subsequent action. The EPA had previously approved 2015 ozone transport SIPs submitted by Oregon and Delaware, but in the proposed FIP action the EPA found these states potentially to be linked in the modeling supporting our proposal. We proposed to issue an error correction for our prior approval of Delaware's 2015 ozone transport SIP; however, in this final rule, the EPA is withdrawing the proposed error correction and the proposed FIP for Delaware, because our updated modeling for this final rule confirms that Delaware is not linked above the 1 percent of NAAQS threshold (*see* section III.C.1 of this document for additional information). The EPA is deferring finalizing a finding at this time for Oregon (*see* section IV.G of this document for additional information).

1. Emissions Limitations for EGUs Established by the Final Rule

In this rule, the EPA is issuing FIP requirements that apply the provisions of the CSAPR NO_X Ozone Season Group 3 Trading Program as revised in the rule to EGU sources within the borders of the following 22 states: Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin. Implementation of the revised trading program provisions begins in the 2023 ozone season.

The EPA is expanding the CSAPR NO_X Ozone Season Group 3 Trading Program beginning in the 2023 ozone season. Specifically, the FIPs require power plants within the borders of the 22 states listed in the previous paragraph to participate in an expanded and revised version of the CSAPR NO_X Ozone Season Group 3 Trading Program created by the Revised CSAPR Update. Affected EGUs within the borders of the following 12 states currently participating in the Group 3 Trading Program under existing FIPs remain in the program, with revised provisions beginning in the 2023 ozone season, under this rule: Illinois, Indiana, Kentucky, Louisiana, Maryland,

[4] We use the terms ''emissions limitation'' and ''emissions limit'' to refer to both numeric emissions limitations and control technology requirements that specify levels of emissions reductions to be achieved.

[5] Bergin, M.S. et al. (2007) Regional air quality: local and interstate impacts of NO_X and SO_2 emissions on ozone and fine particulate matter in the eastern United States. Environmental Sci & Tech. 41: 4677–4689.

[6] Liao, K. et al. (2013) Impacts of interstate transport of pollutants on high ozone events over the Mid-Atlantic United States. Atmospheric Environment 84, 100–112.

[7] *See* 82 FR 51238, 51248 (November 3, 2017) [citing 76 FR 48208, 48222 (August 8, 2011)] and 63 FR 57381 (October 27, 1998).

[8] 42 U.S.C. 7410(a)(2)(D)(i)(I).

Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. The FIPs also require affected EGUs within the borders of the following seven states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program (the ''Group 2 trading program'') under existing FIPs or existing SIPs to transition from the Group 2 program to the revised Group 3 trading program beginning with the 2023 control period: Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin.[9] Finally, the EPA is issuing new FIPs for EGUs within the borders of three states not currently covered by any existing CSAPR trading program for seasonal NO_X emissions: Minnesota, Nevada, and Utah. Sources in these states will enter the Group 3 trading program in the 2023 control period following the effective date of the final rule.[10] Refer to section VI.B of this document for details on EGU regulatory requirements.

2. Emissions Limitations for Industrial Stationary Point Sources Established by the Final Rule

The EPA is issuing FIP requirements that include new NO_X emissions limitations for industrial or non-EGU sources in 20 states, with sources expected to demonstrate compliance no later than 2026. The EPA is requiring emissions reductions from non-EGU sources to address interstate transport obligations for the 2015 ozone NAAQS for the following 20 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia and West Virginia.

The EPA is establishing emissions limitations for the following unit types in non-EGU industries: reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; kilns in Cement and Cement Product Manufacturing; reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and combustors and incinerators in Solid Waste Combustors and Incinerators. Refer to Table II.A–1 for a list of North American Industry Classification System (NAICS) codes for each entity included for regulation under this rule.

B. Summary of the Regulatory Framework of the Rule

The EPA is applying the 4-step interstate transport framework developed and used in CSAPR, the CSAPR Update, the Revised CSAPR Update, and other previous ozone transport rules under the authority provided in CAA section 110(a)(2)(D)(i)(I). The 4-step interstate transport framework provides a stepwise method for the EPA to define and implement good neighbor obligations for the 2015 ozone NAAQS. The four steps are as follows: (Step 1) identifying downwind receptors that are expected to have problems attaining or maintaining the NAAQS; (Step 2) determining which upwind states contribute to these identified problems in amounts sufficient to ''link'' them to the downwind air quality problems (*i.e.,* in this rule as in prior transport rules beginning with CSAPR in 2011, above a contribution threshold of 1 percent of the NAAQS); (Step 3) for states linked to downwind air quality problems, identifying upwind emissions that significantly contribute to downwind nonattainment or interfere with downwind maintenance of the NAAQS through a multifactor analysis; and (Step 4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind areas, implementing the necessary emissions reductions through enforceable measures. The remainder of this section provides a general overview of the EPA's application of the 4-step framework as it applies to the provisions of the rule; additional details regarding the EPA's approach are found in section III of this document.

To apply the first step of the 4-step framework to the 2015 ozone NAAQS, the EPA performed air quality modeling to project ozone concentrations at air quality monitoring sites in 2023 and 2026.[11] The EPA evaluated projected ozone concentrations for the 2023 analytic year at individual monitoring sites and considered current ozone monitoring data at these sites to identify receptors that are anticipated to have problems attaining or maintaining the 2015 ozone NAAQS. This analysis of projected ozone concentrations was then repeated for 2026.

To apply the second step of the framework, the EPA used air quality modeling to quantify the contributions from upwind states to ozone concentrations in 2023 and 2026 at downwind receptors.[12] Once quantified, the EPA then evaluated these contributions relative to a screening threshold of 1 percent of the NAAQS (*i.e.,* 0.70 ppb).[13] States with contributions that equaled or exceeded 1 percent of the NAAQS were identified as warranting further analysis at Step 3 of the 4-step framework to determine if the upwind state significantly contributes to nonattainment or interference with maintenance in a downwind state. States with contributions below 1 percent of the NAAQS were considered not to significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind states.

Based on the EPA's most recent air quality modeling and contribution analysis using 2023 as the analytic year, the EPA finds that the following 23 states have contributions that equal or exceed 1 percent of the 2015 ozone NAAQS, and, thereby, warrant further analysis of significant contribution to nonattainment or interference with maintenance of the NAAQS: Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin.

There are locations in California to which Oregon contributes greater than 1 percent of the NAAQS; the EPA

[9] Five of these seven states (Arkansas, Mississippi, Oklahoma, Texas, and Wisconsin) currently participate in the Federal Group 2 trading program pursuant to the FIPs finalized in the CSAPR Update. The FIPs required under this rule amend the existing FIPs for these states. The other two states (Alabama and Missouri) have already replaced the FIPs finalized in the CSAPR Update with approved SIP revisions that require their EGUs to participate in state Group 2 trading programs integrated with the Federal Group 2 trading program, so the FIPs required in this action constitute new FIPs for these states. The EPA will cease implementation of the state Group 2 trading programs included in the two states' SIPs on the effective date of this rule.

[10] Three states, Kansas, Iowa, and Tennessee, will remain in the Group 2 Trading Program.

[11] These 2 analytic years are the last full ozone seasons before, and thus align with, upcoming attainment dates for the 2015 ozone NAAQS: August 3, 2024, for areas classified as Moderate nonattainment, and August 3, 2027, for areas classified as Serious nonattainment. *See* 83 FR 25776.

[12] The EPA performed air quality modeling for 2032 in the proposed rulemaking, but did not perform contribution modeling for 2032 since contribution data for this year were not needed to identify upwind states to be analyzed in Step 3. The modeling of 2032 done at proposal using the 2016v2 platform does not constitute or represent any final agency determinations respecting air quality conditions or regulatory judgments with respect to good neighbor obligations or any other CAA requirements.

[13] *See* section IV.F of this document for explanation of EPA's use of the 1 percent of the NAAQS threshold in the Step 2 analysis.

proposed that downwind areas represented by these monitoring sites in California should not be considered interstate ozone transport receptors at Step 1. However, the EPA is deferring finalizing a finding at this time for Oregon (*see* section IV.G of this document for additional information).

Based on the air quality analysis presented in section IV of this document, the EPA finds that, with the exception of Alabama, Minnesota, and Wisconsin, the states found linked in 2023 will continue to contribute above the 1 percent of the NAAQS threshold to at least one receptor whose nonattainment and maintenance concerns persist through the 2026 ozone season. As a result, the EPA's evaluation of significantly contributing emissions at Step 3 for Alabama, Minnesota, and Wisconsin is limited to emissions reductions achievable by the 2023 and 2024 ozone seasons.

At the third step of the 4-step framework, the EPA applied a multifactor test that incorporates cost, availability of emissions reductions, and air quality impacts at the downwind receptors to determine the amount of ozone precursor emissions from the linked upwind states that ''significantly'' contribute to downwind nonattainment or maintenance receptors. The EPA is applying the multifactor test described in section V.A of this document to both EGU and industrial sources. The EPA assessed the potential emissions reductions in 2023 and 2026,[14] as well as in intervening and later years to determine the emissions reductions required to eliminate significant contribution in 2023 and future years where downwind areas are projected to have potential problems attaining or maintaining the 2015 ozone NAAQS.

For EGU sources, the EPA evaluated the following set of widely-available NO_X emissions control technologies: (1) fully operating existing selective catalytic reduction (SCR) controls, including both optimizing NO_X removal by existing operational SCRs and turning on and optimizing existing idled SCRs; (2) installing state-of-the-art NO_X combustion controls; (3) fully operating existing selective non-catalytic reduction (SNCR) controls, including both optimizing NO_X removal by existing operational SNCRs and turning on and optimizing existing idled SNCRs; (4) installing new SNCRs; (5) installing new SCRs; and (6) generation shifting. For the reasons explained in section V of this document and supported by the ''Technical Support Document (TSD) for the Final Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standard, Docket ID No. EPA–HQ–OAR–2021–0668, EGU NO_X Mitigation Strategies Final Rule TSD'' (Mar. 2023), hereinafter referred to as the EGU NO_X Mitigation Strategies Final Rule TSD, included in the docket for this action, the EPA determines that for the regional, multi-state scale of this rulemaking, only fully operating and optimizing existing SCRs and existing SNCRs (EGU NO_X emissions controls options 1 and 3 in the list earlier) are possible for the 2023 ozone season. The EPA determined that state-of-the-art NO_X combustion controls at EGUs (emissions control option 2 in the list above) are available by the beginning of the 2024 ozone season. *See* section V.B.1 of this document for a full discussion of EPA's analysis of NO_X emissions mitigation strategies for EGU sources.

The EPA is requiring control stringency levels that offer the most incremental NO_X emissions reduction potential from EGUs—among the uniform mitigation measures assessed for the covered region—and the most corresponding downwind ozone air quality improvements to the extent feasible in each year analyzed. The EPA is making a finding that the required controls provide cost-effective reductions of NO_X emissions that will provide substantial improvements in downwind ozone air quality to address interstate transport obligations for the 2015 ozone NAAQS in a timely manner. These controls represent greater stringency in upwind EGU controls than in the EPA's most recent ozone transport rulemakings, such as the CSAPR Update and the Revised CSAPR Update. However, programs to address interstate ozone transport based on the retrofit of post-combustion controls are by no means unprecedented. In prior ozone transport rulemakings such as the NO_X SIP Call and the Clean Air Interstate Rule (CAIR), the EPA established EGU budgets premised on the widespread availability of retrofitting EGUs with post-combustion emissions controls such as SCR.[15] While these programs successfully drove many EGUs to retrofit post-combustion controls, other EGUs throughout the present geography of linked upwind states continue to operate without such controls and continue to emit at relatively high rates more than 20 years after similar units reduced these emissions under prior interstate ozone transport rulemakings.

Furthermore, the CSAPR Update provided only a partial remedy for eliminating significant contribution for the 2008 ozone NAAQS, as needed to obtain available reductions by the 2017 ozone season. In that rule, the EPA made no determination regarding the appropriateness of more stringent EGU NO_X controls that would be required for a *full* remedy for interstate transport for the 2008 ozone NAAQS. Following the remand of the CSAPR Update in *Wisconsin* v. *EPA,* 938 F.3d 303 (D.C. Cir. 2019) (*Wisconsin*), the EPA again declined to require the retrofit of new post-combustion controls on EGUs in the Revised CSAPR Update, but that determination was based on a specific timing consideration: downwind air quality problems under the 2008 ozone NAAQS were projected to resolve before post-combustion control retrofits could be accomplished on a fleetwide, regional scale. *See* 86 FR 23054, 23110 (April 30, 2021).

In this rulemaking, the EPA is addressing good neighbor obligations for the more protective 2015 ozone NAAQS, and the Agency observes ongoing and persistent contribution from upwind states to ozone nonattainment and maintenance receptors in downwind states under that NAAQS. As further discussed in section V of this document, the nature of this contribution warrants a greater degree of control stringency than the EPA determined to be necessary to eliminate significant contribution of ozone transport in prior CSAPR rulemakings. In this rule, the EPA is requiring emissions performance levels for EGU NO_X control strategies commensurate with those determined to be necessary in the NO_X SIP Call and CAIR.

Based on the Step 3 analysis described in section V of this document, the EPA finds that emissions reductions commensurate with the full operation of all existing post-combustion controls (both SCRs and SNCRs) and state-of-the-art combustion control upgrades constitute the Agency's selected control stringency for EGUs within the borders of 22 states linked to downwind

[14] The EPA included emissions reductions from the potential installation of SCRs at all affected large coal-fired EGUs in the 2026 analytic year for the purposes of assessing significant contribution to nonattainment and interference with maintenance, which is consistent with the associated attainment date. However, in response to comments identifying potential supply chain and outage scheduling challenges if the full breadth of these assumed SCR installations were to occur, the EPA is implementing half of this emissions reduction potential in 2026 ozone-season NO_X budgets for states containing these EGUs and the other half of this emissions reduction potential in 2027 ozone-season NO_X budgets for those states.

[15] *See, e.g.,* 70 FR 25162, 25205–06 (May 12, 2005).

nonattainment or maintenance in 2023 (Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin). For 19 of those states that are also linked in 2026 (Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia), the EPA is determining that the selected EGU control stringency also includes emissions reductions commensurate with the retrofit of SCR at coal-fired units of 100 MW or greater capacity (excepting circulating fluidized bed units (CFB)), new SNCR on coal-fired units of less than 100 MW capacity and on CFBs of any capacity size, and SCR on oil/gas steam units greater than 100 MW that have historically emitted at least 150 tons of NO_X per ozone season.

To identify appropriate control strategies for non-EGU sources to achieve NO_X emissions reductions that would result in meaningful air quality improvements in downwind areas, for the proposed FIP, the EPA evaluated air quality modeling information, annual emissions, and information about potential controls to determine which industries, beyond the power sector, could have the greatest impact in providing ozone air quality improvements in affected downwind states. Once the EPA identified the industries, the EPA used its Control Strategy Tool to identify potential emissions units and control measures and to estimate emissions reductions and compliance costs associated with application of non-EGU emissions control measures. The technical memorandum *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* lays out the analytical framework and data used to prepare proxy estimates for 2026 of potentially affected non-EGU facilities and emissions units, emissions reductions, and costs.[16] [17] This information helped shape the proposal and final rule. To further evaluate the industries and emissions unit types identified by the screening assessment and to establish the applicability criteria and proposed emissions limits, the EPA reviewed Reasonably Available Control Technology (RACT) rules, New Source Performance Standards (NSPS) rules, National Emissions Standards for Hazardous Air Pollutants (NESHAP) rules, existing technical studies, rules in approved SIPs, consent decrees, and permit limits. That evaluation is detailed in the ''Technical Support Document (TSD) for the Proposed Rule, Docket ID No. EPA–HQ–OAR–2021–0668, Non-EGU Sectors TSD'' (Dec. 2021), hereinafter referred to as the Proposed Non-EGU Sectors TSD, prepared for the proposed FIP.[18]

In this final rule, the EPA is retaining the industries and many of the emissions unit types included in the proposal in its findings of significant contribution at Step 3, as discussed in section V of this document. As discussed in the memorandum for the final rule, titled ''Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs,'' the EPA uses the 2019 emissions inventory, the list of emissions units estimated to be captured by the applicability criteria, the assumed control technologies that would meet the emissions limits, and information on control efficiencies and default cost/ton values from the Control Measures Database,[19] to estimate NO_X emissions reductions and costs for the year 2026. In this final rule, the EPA made changes to the applicability criteria and emissions limits following consideration of comments on the proposal and reassessed the overall non-EGU emissions reduction strategy based on the factors at Step 3 to render a judgment as to whether the level of emissions control that would be achievable from these units meets the criteria for ''significant contribution.'' In the final rule, we affirm our proposed determinations of which industries and emissions units are potentially impactful and warrant further analysis at Step 3, and we find that the available emissions reductions are cost-effective and make meaningful improvements at the identified downwind receptors. For a detailed discussion of the changes, between the proposal and this final rule, in emissions unit types included and in emissions limits, see section VI.C. of this document.

The EPA performed air quality analysis using the Ozone Air Quality Assessment Tool (AQAT) to evaluate the air quality improvements anticipated to result from the implementation of the selected EGU and non-EGU emissions reduction strategies. See section V.D of this document.[20] We also used AQAT to determine whether the emissions reductions for both EGUs and non-EGUs potentially create an ''over-control'' scenario. As in prior transport rules following the holdings in *EME Homer City,* overcontrol would be established if the record indicated that, for any given state, there is a less stringent emissions control approach for that state, by which (1) the expected ozone improvements would be sufficient to resolve all of the downwind receptor(s) to which that state is linked; or (2) the expected ozone improvements would reduce the upwind state's ozone contributions below the screening threshold (*i.e.,* 1 percent of the NAAQS or 0.70 ppb) to all of linked receptors. The EPA's over-control analysis, discussed in section V.D.4 of this document, shows that the control stringencies for EGU and non-EGU sources in this final rule do not over-control upwind states' emissions either with respect to the downwind air quality problems to which they are linked or with respect to the 1 percent of the NAAQS contribution threshold, such that over-control would trigger re-evaluation at Step 3 for any linked upwind state.

Based on the multi-factor test applied to both EGU and non-EGU sources and

[16] The memorandum is available in the docket at *https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150.*

[17] This screening assessment was not intended to identify the specific emissions units subject to the proposed emissions limits for non-EGU sources but was intended to inform the development of the proposed rule by identifying proxies for (1) non-EGU emissions units that had emissions reduction potential, (2) potential controls for and emissions reductions from these emissions units, and (3) control costs from the potential controls on these emissions units. This information helped shape the proposed rule.

[18] The TSD is available in the docket at *https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145.*

[19] More information about the control measures database (CMDB) can be found at the following link: *https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.*

[20] The use of AQAT and other simplified modeling tools to generate ''appropriately reliable projections of air quality conditions and contributions'' when there is limited time to conduct full-scale photochemical grid modeling was upheld by the D.C. Circuit in *MOG* v. *EPA,* No. 21–1146 (D.C. Cir. March 3, 2023). The EPA has used AQAT for the purpose of air quality and overcontrol assessments at Step 3 in the prior CSAPR rulemakings, and we continue to find it reliable for such purposes. We discuss the calibration of AQAT for this action and the multiple sensitivity checks we performed to ensure its reliability in the Ozone Transport Policy Analysis Final Rule TSD in the docket. Because we were able to conduct a photochemical grid modeling run of the 2026 final rule policy scenario, these results are also included in the docket and confirm the regulatory conclusions reached with AQAT. *See* section VIII of this document and Appendix 3A of the Final Rule RIA for more information.

our subsequent assessment of over-control, the EPA finds that the selected EGU and non-EGU control stringencies constitute the elimination of significant contribution and interference with maintenance, without over-controlling emissions, from the 23 upwind states subject to EGU and non-EGU emissions reductions requirements under the rule. For additional details about the multi-factor test and the over-control analysis, *see* the document titled ''Technical Support Document (TSD) for the Final Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standard, Docket ID No. EPA–HQ–OAR–2021–0668, Ozone Transport Policy Analysis Proposed Rule TSD'' (Mar. 2023), hereinafter referred to as Ozone Transport Policy Analysis Final Rule TSD, included in the docket for this rulemaking.

In this fourth step of the 4-step framework, the EPA is including enforceable measures in the promulgated FIPs to achieve the required emissions reductions in each of the 23 states. Specifically, the FIPs require covered power plants within the borders of 22 states (Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin) to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program created by the Revised CSAPR Update. Affected EGUs within the borders of the following 12 states currently participating in the Group 3 Trading Program will remain in the program, with revised provisions beginning in the 2023 ozone season, under this rule: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. Affected EGUs within the borders of the following seven states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program (the ''Group 2 trading program'')—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin—will transition from the Group 2 program to the revised Group 3 trading program beginning with the 2023 control period,[21] and affected EGUs within the borders of three states not currently covered by any CSAPR trading program for seasonal NO_X emissions—Minnesota, Nevada, and Utah—will enter the Group 3 trading program in the 2023 control period following the effective date of the final rule. In addition, the EPA is revising other aspects of the Group 3 trading program to better ensure that this method of implementation at Step 4 provides a durable remedy for the elimination of the amount of emissions deemed to constitute significant contribution at Step 3 of the interstate transport framework. These enhancements, summarized later in this section, are designed to operate together to maintain that degree of control stringency over time, thus improving emissions performance at individual units and offering a necessary measure of assurance that NO_X pollution controls will be operated throughout each ozone season, as described in section VI.B of this document. This rulemaking does not revise the budget stringency and geography of the existing CSAPR NO_X Ozone Season Group 1 trading program. Aside from the seven states moving from the Group 2 trading program to the Group 3 trading program under the final rule, this rule otherwise leaves unchanged the budget stringency of the existing CSAPR NO_X Ozone Season Group 2 trading program.

The EPA is establishing preset ozone season NO_X emissions budgets for each ozone season from 2023 through 2029, using generally the same Group 3 trading program budget-setting methodology used in the Revised CSAPR Update, as explained in section VI.B of this document and as shown in Table I.B–1. The preset budgets for the 2026 through 2029 ozone seasons incorporate EGU emissions reductions to eliminate significant contribution and also take into account a substantial number of known retirements over that period to ensure the elimination of significant contribution is maintained as intended by this rule. These budgets serve as floors and may be supplanted by a budget that the EPA calculates for that control period using more recent information (a ''dynamic budget'') if that dynamic budget yields a higher level of allowable emissions—still consistent with the Step 3 level of emissions control stringency—than the preset budget. As reflected in Table I.B–1, and accounting for both the stringency of the rule and known fleet change, the 2026 preset budget is 23 percent lower than the 2025 preset budget; the 2027 preset budget is 20 percent lower than the 2026 preset budget; the 2028 preset budget is 4 percent lower than the 2027 preset budget; and the 2029 preset budget is 8 percent lower than the 2028 preset budget.

While it is possible that additional EGUs may seek to retire in this 2026–2029 period than are currently scheduled and captured in the preset emissions budgets, it is also possible that EGUs with currently scheduled retirements may adjust their retirement timing to accommodate the timing of replacement generation and/or transmission upgrades necessitated by their retirement. While the EPA designed this final rule to provide preset budgets through 2029 to incorporate known retirement-related emissions reductions to ensure the elimination of significant contribution as identified at Step 3 is maintained over time, the use of these floors also provides generators and grid operators enhanced certainty regarding the minimum amount of allowable NO_X emissions for reliability planning through the 2020s. By providing the opportunity for dynamic budgets to subsequently calibrate budgets to any unforeseen increases in fleet demand, it also ensures this rule will not interfere with ongoing retirement scheduling or adjustments and thus is robust to future uncertainty during a transition period.

The EPA also believes the likelihood and magnitude of a scenario in which a state's preset emissions budgets during this period would authorize more emissions than the corresponding dynamic budget is low. As described elsewhere, dynamic budgets are incorporated to best calibrate the rule's stringency to future unknown changes to the fleet. The circumstances in which a dynamic budget would produce a level of allowable emissions less than preset budgets is most pronounced for future periods in which there is a high degree of unknown retirements (increasing the risk that budgets are not appropriately calibrated to the reduced fossil fuel heat input post retirement). However, the 2026–2029 period presents a case where retirement planning has been announced with greater lead time than normal due to a combination of utility 2030 decarbonization commitments, and Effluent Limitation Guideline (ELG) and Coal Combustion Residual (CCR) alternative compliance pathways available to units planning to cease combustion of coal by December 31, 2028. For each of these existing rules, facilities that are planning to retire have already conveyed that intention to EPA in order to take advantage of the alternative compliance pathways

[21] The EPA will deem participation in the Group 3 trading program by the EGUs in these seven states as also addressing the respective states' good neighbor obligations with respect to the 2008 ozone NAAQS (for all seven states), the 1997 ozone NAAQS (for all the states except Texas), and the 1979 ozone NAAQS (for Alabama and Missouri) to the same extent that those obligations are currently being addressed by participation of the states' EGUs in the Group 2 trading program.

available to such facilities.[22] Therefore, the likelihood of unknown retirements—leading to lower dynamic budgets—is much lower than typical for this time horizon. This makes EPA's balanced use of preset emissions budgets or dynamic budgets if they exceed preset levels a reasonable mechanism to accommodate planning and fleet transition dynamics during this period. The need and reasoning for the limited-period preset budget floor is further discussed in section VI.B.4.

For control periods in 2030 and thereafter, the emissions budgets will be the amounts calculated for each state and noticed to the public roughly one year before the control period, using the dynamic budget-setting methodology. In this manner, the stringency of the program will be secured and sustained in the dynamic budgets of this program, regardless of whatever EGU transition activities ultimately occur in this 2026–2029 transition period.

TABLE I.B–1—PRESET CSAPR NO_X OZONE SEASON GROUP 3 STATE EMISSIONS BUDGETS (TONS) FOR 2023 THROUGH 2029 CONTROL PERIODS *

State	2023 State budget	2024 State budget	2025 State budget	2026 State budget **	2027 State budget **	2028 State budget **	2029 State budget **
Alabama	6,379	6,489	6,489	6,339	6,236	6,236	5,105
Arkansas	8,927	8,927	8,927	6,365	4,031	4,031	3,582
Illinois	7,474	7,325	7,325	5,889	5,363	4,555	4,050
Indiana	12,440	11,413	11,413	8,410	8,135	7,280	5,808
Kentucky	13,601	12,999	12,472	10,190	7,908	7,837	7,392
Louisiana	9,363	9,363	9,107	6,370	3,792	3,792	3,639
Maryland	1,206	1,206	1,206	842	842	842	842
Michigan	10,727	10,275	10,275	6,743	5,691	5,691	4,656
Minnesota	5,504	4,058	4,058	4,058	2,905	2,905	2,578
Mississippi	6,210	5,058	5,037	3,484	2,084	1,752	1,752
Missouri	12,598	11,116	11,116	9,248	7,329	7,329	7,329
Nevada	2,368	2,589	2,545	1,142	1,113	1,113	880
New Jersey	773	773	773	773	773	773	773
New York	3,912	3,912	3,912	3,650	3,388	3,388	3,388
Ohio	9,110	7,929	7,929	7,929	7,929	6,911	6,409
Oklahoma	10,271	9,384	9,376	6,631	3,917	3,917	3,917
Pennsylvania	8,138	8,138	8,138	7,512	7,158	7,158	4,828
Texas	40,134	40,134	38,542	31,123	23,009	21,623	20,635
Utah	15,755	15,917	15,917	6,258	2,593	2,593	2,593
Virginia	3,143	2,756	2,756	2,565	2,373	2,373	1,951
West Virginia	13,791	11,958	11,958	10,818	9,678	9,678	9,678
Wisconsin	6,295	6,295	5,988	4,990	3,416	3,416	3,416
Total	208,119	198,014	195,259	151,329	119,663	115,193	105,201

* Further information on the state-level emissions budget calculations pertaining to Table I.B–1 is provided in section VI.B.4 of this document as well as the Ozone Transport Policy Analysis Final Rule TSD. Further information on the approach for allocating a portion of Utah's emissions budget for each control period to the existing EGU in the Uintah and Ouray Reservation within Utah's borders is provided in section VI.B.9 of this document.

** As described in section VI of this document, the budget for these years will be subsequently determined and equal the greater of the value above or that derived from the dynamic budget methodology.

The budget-setting methodology that the EPA will use to determine dynamic budgets for each control period starting with 2026 is an extension of the methodology used to determine the preset budgets and will be used routinely to determine emissions budgets for each future control period in the year before that control period, with each emissions budget reflecting the latest available information on the composition and utilization of the EGU fleet at the time that emissions budget is determined. The stringency of the dynamic emissions budgets will simply reflect the stringency of the emissions control strategies selected in the rulemaking more consistently over time and ensure that the annual updates would eliminate emissions determined to be unlawful under the good neighbor provision. As already noted, for the control periods in which both preset budgets and dynamic budgets are determined for a state (*i.e.,* 2026 through 2029), the state's dynamic budget will apply only if it is higher than the state's preset budget. *See* section VI.B of this document for additional discussion of the EPA's method for adjusting emissions budgets to ensure elimination of significant contribution from EGU sources in the linked upwind states.

In conjunction with the levels of the emissions budgets, the carryover of unused allowances for use in future control periods as banked allowances affects the ability of a trading program to maintain the rule's selected control stringency and related EGU effective emissions rate performance level as the EGU fleet evolves over time. Unrestricted banking of allowances allows what might otherwise be temporary surpluses of allowances in some individual control periods to accumulate into a long-term allowance surplus that reduces allowance prices and weakens the trading program's incentives to control emissions. To prevent this outcome, the EPA is also revising the Group 3 trading program by adding provisions that establish a routine recalibration process for banked allowances using a target percentage of 21 percent for the 2024–2029 control periods and 10.5 percent for control periods in 2030 and later years.

As an enhancement to the structure of the trading program originally promulgated in the Revised CSAPR Update, the EPA is also establishing backstop daily emissions rates for coal

[22] Notices of Planned Participation for the ELG Reconsideration Rule were due October 31, 2021 (85 FR 64708, 64679). For the CCR Action, facilities had to indicate their future plans to cease receipt of waste by April 11, 2021 (85 FR 53517).

steam EGUs greater than or equal to 100 MW in covered states. Starting with the 2024 control period, a 3-for-1 allowance surrender ratio (instead of the usual 1-for-1 surrender ratio) will apply to emissions during the ozone season from any large coal-fired EGU with existing SCR controls exceeding by more than 50 tons a daily average NO_X emissions rate of 0.14 lb/mmBtu. The daily average emissions rate provisions will apply to large coal-fired EGUs without existing SCR controls starting with the second control period in which newly installed SCR controls are operational at the unit, but not later than the 2030 control period.

The backstop daily emissions rates work in tandem with the ozone season emissions budgets to ensure the elimination of significant contribution as determined at Step 3 is maintained over time and more consistently throughout each ozone season. They will offer downwind receptor areas a necessary measure of assurance that they will be protected on a daily basis during the ozone season by more continuous and consistent operation of installed pollution controls. The EPA's experience with the CSAPR trading programs has revealed instances where EGUs have reduced their SCRs' performance on a given day, or across the entire ozone seasons in some cases, including high ozone days.[23] In addition to maintaining a mass-based seasonal requirement, this rule will achieve a much more consistent level of emissions control in line with our Step 3 determination of significant contribution while maintaining compliance flexibility consistent with that determination. These trading program improvements will promote consistent emissions control performance across the power sector in the linked upwind states, which protects communities living in downwind ozone nonattainment areas from exceedances of the NAAQS that might otherwise occur.

The EPA is including enforceable emissions control requirements that will apply during the ozone season (annually from May to September) for nine non-EGU industries in the promulgated FIPs to achieve the required emissions reductions in 20 states with remaining interstate transport obligations for the 2015 ozone NAAQS in 2026: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. These requirements would apply to all existing emissions units and to any future emissions units constructed in the covered states that meet the relevant applicability criteria. Thus, the emissions limitations for non-EGU sources and associated compliance requirements would apply in all 20 states listed in this paragraph, even if some of these states do not currently have any existing emissions units meeting the applicability criteria for the identified industries.

Based on our evaluation of the time required to install controls at the types of non-EGU sources covered by this rule, the EPA has identified the 2026 ozone season as a reasonable compliance date for industrial sources. The EPA is therefore finalizing control requirements for non-EGU sources that take effect in 2026. However, in recognition of comments and additional information indicating that not all facilities may be capable of meeting the control requirements by that time, the final rule provides a process by which the EPA may grant compliance extensions of up to 1 year, which if approved by the EPA, would require compliance no later than the 2027 ozone season, followed by an additional possible extension of up to 2 more years, where specific criteria are met. For sources located in the 20 states listed in the previous paragraph, the EPA is finalizing the NO_X emissions limits listed in Table I.B–2 for reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; the NO_X emissions limits listed in Table I.B–3 for kilns in Cement and Cement Product Manufacturing; the NO_X emissions limits listed in Table I.B–4 for reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; the NO_X emissions limits listed in Table I.B–5 for furnaces in Glass and Glass Product Manufacturing; the NO_X emissions limits listed in Table I.B–6 for boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and the NO_X emissions limits listed in Table I.B–7 for combustors and incinerators in Solid Waste Combustors or Incinerators.

TABLE I.B–2—SUMMARY OF NO_X EMISSIONS LIMITS FOR PIPELINE TRANSPORTATION OF NATURAL GAS

Engine type and fuel	NO_X emissions limit (g/hp-hr)
Natural Gas Fired Four Stroke Rich Burn	1.0
Natural Gas Fired Four Stroke Lean Burn	1.5
Natural Gas Fired Two Stroke Lean Burn	3.0

TABLE I.B–3—SUMMARY OF NO_X EMISSIONS LIMITS FOR KILN TYPES IN CEMENT AND CONCRETE PRODUCT MANUFACTURING

Kiln type	NO_X emissions limit (lb/ton of clinker)
Long Wet	4.0
Long Dry	3.0
Preheater	3.8
Precalciner	2.3
Preheater/Precalciner	2.8

[23] *See* 86 FR 23090. The EPA highlighted the Miami Fort Unit 7 (possessing a SCR) more than tripled its ozone-season NO_X emission rate between 2017 and 2019.

Based on evaluation of comments received, the EPA is not, at this time, finalizing the source cap limit as proposed at 87 FR 20046 (*see* section VII.C.2 of the April 6, 2022, Proposal).

TABLE I.B–4—SUMMARY OF NO_X CONTROL REQUIREMENTS FOR IRON AND STEEL AND FERROALLOY EMISSIONS UNITS

Emissions unit	NO_X emissions standard or requirement (lb/mmBtu)
Reheat furnace	Test and set limit based on installation of Low-NO_X Burners.

TABLE I.B–5—SUMMARY OF NO_X EMISSIONS LIMITS FOR FURNACE UNIT TYPES IN GLASS AND GLASS PRODUCT MANUFACTURING

Furnace type	NO_X emissions limit (lb/ton of glass produced)
Container Glass Manufacturing Furnace	4.0
Pressed/Blown Glass Manufacturing Furnace or Fiberglass Manufacturing Furnace	4.0
Flat Glass Manufacturing Furnace	7.0

TABLE I.B–6—SUMMARY OF NO_X EMISSIONS LIMITS FOR BOILERS IN IRON AND STEEL AND FERROALLOY MANUFACTURING, METAL ORE MINING, BASIC CHEMICAL MANUFACTURING, PETROLEUM AND COAL PRODUCTS MANUFACTURING, AND PULP, PAPER, AND PAPERBOARD MILLS

Unit type	Emissions limit (lbs NO_X/mmBtu)
Coal	0.20
Residual oil	0.20
Distillate oil	0.12
Natural gas	0.08

TABLE I.B–7—SUMMARY OF NO_X EMISSIONS LIMITS FOR COMBUSTORS AND INCINERATORS IN SOLID WASTE COMBUSTORS OR INCINERATORS

Combustor or incinerator, averaging period	NO_X emissions limit (ppmvd)
ppmvd on a 24-hour block averaging period	110
ppmvd on a 30-day rolling averaging period	105

Section VI.C of this document provides an overview of the applicability criteria, compliance assurance requirements, and the EPA's rationale for establishing these emissions limits and control requirements for each of the non-EGU industries covered by the rule.

The remainder of this preamble is organized as follows: section II of this document outlines general applicability criteria and describes the EPA's legal authority for this rule and the relationship of the rule to previous interstate ozone transport rulemakings. Section III of this document describes the human health and environmental challenges posed by interstate transport contributions to ozone air quality problems, as well as the EPA's overall approach for addressing interstate transport for the 2015 ozone NAAQS in this rule. Section IV of this document describes the Agency's analyses of air quality data to inform this rulemaking, including descriptions of the air quality modeling platform and emissions inventories used in the rule, as well as the EPA's methods for identifying downwind air quality problems and upwind states' ozone transport contributions to downwind states. Section V of this document describes the EPA's approach to quantifying upwind states' obligations in the form of EGU NO_X control stringencies and non-EGU emissions limits. Section VI of this document describes key elements of the implementation schedule for EGU and non-EGU emissions reductions requirements, including details regarding the revised aspects of the CSAPR NO_X Group 3 trading program and compliance deadlines, as well as regulatory requirements and compliance deadlines for non-EGU sources. Section VII of this document discusses the environmental justice analysis of the rule, as well as outreach and engagement efforts. Section VIII of this document describes the expected costs, benefits, and other impacts of this rule. Section IX of this document provides a summary of changes to the existing regulatory text applicable to the EGUs covered by this rule; and section X of this document discusses the statutory and executive orders affecting this rulemaking.

C. Costs and Benefits

A summary of the key results of the cost-benefit analysis that was prepared for this final rule is presented in Table I.C–1. Table I.C–1 presents estimates of the present values (PV) and equivalent annualized values (EAV), calculated using discount rates of 3 and 7 percent as recommended by OMB's Circular A–4, of the health and climate benefits, compliance costs, and net benefits of the final rule, in 2016 dollars, discounted to 2023. The estimated monetized net benefits are the estimated monetized benefits minus the estimated monetized costs of the final rule. These results present an incomplete overview of the effects of the rule because important categories of benefits—including benefits from reducing other types of air pollutants, and water pollution—were not monetized and are therefore not reflected in the cost-benefit tables. We anticipate that taking non-monetized effects into account would show the rule to be more net beneficial than this table reflects.

TABLE I.C–1—ESTIMATED MONETIZED HEALTH AND CLIMATE BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS OF THE FINAL RULE, 2023 THROUGH 2042

[Millions 2016$, discounted to 2023] [a]

	3% Discount rate	7% Discount rate
Present Value:		
Health Benefits [b]	$200,000	$130,000
Climate Benefits [c]	15,000	15,000
Compliance Costs [d]	14,000	9,400
Net Benefits	200,000	140,000
Equivalent Annualized Value:		
Health Benefits	13,000	12,000
Climate Benefits	970	970
Compliance Costs	910	770
Net Benefits	13,000	12,000

[a] Rows may not appear to add correctly due to rounding.

[b] The annualized present value of costs and benefits are calculated over a 20-year period from 2023 to 2042. Monetized benefits include those related to public health associated with reductions in ozone and $PM_{2.5}$ concentrations. The health benefits are associated with two point estimates and are presented at real discount rates of 3 and 7 percent. Several categories of benefits remain unmonetized and are thus not reflected in the table.

[c] Climate benefits are calculated using four different estimates of the social cost of carbon ($SC\text{–}CO_2$ (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For presentational purposes in this table, the climate benefits associated with the average $SC\text{–}CO_2$ at a 3-percent discount rate are used in the columns displaying results of other costs and benefits that are discounted at either a 3-percent or 7-percent discount rate.

[d] The costs presented in this table are consistent with the costs presented in Chapter 4 of the *Regulatory Impact Analysis (RIA).* To estimate these annualized costs for EGUs, the EPA uses a conventional and widely accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses. Costs were calculated using a 3.76 percent real discount rate consistent with the rate used in IPM's objective function for cost-minimization. For further information on the discount rate use, please see Chapter 4, Table 4–8 in the RIA.

As shown in Table I.C–1, the PV of the monetized health benefits, associated with reductions in ozone and $PM_{2.5}$ concentrations, of this final rule, discounted at a 3-percent discount rate, is estimated to be about $200 billion ($200,000 million), with an EAV of about $13 billion ($13,000 million). At a 7-percent discount rate, the PV of the monetized health benefits is estimated to be $130 billion ($130,000 million), with an EAV of about $12 billion ($12,000 million). The PV of the monetized climate benefits, associated with reductions in GHG emissions, of this final rule, discounted at a 3-percent discount rate, is estimated to be about $15 billion ($15,000 million), with an EAV of about $970 million. The PV of the monetized compliance costs, discounted at a 3-percent rate, is estimated to be about $14 billion ($14,000 million), with an EAV of about $910 million. At a 7-percent discount rate, the PV of the compliance costs is estimated to be about $9.4 billion ($9,400 million), with an EAV of about $770 million.

II. General Information

A. Does this action apply to me?

This rule affects EGU and non-EGU sources, and regulates the groups identified in Table II.A–1.

TABLE II.A–1—REGULATED GROUPS

Industry group	NAICS
Fossil fuel-fired electric power generation	221112
Pipeline Transportation of Natural Gas	4862
Metal Ore Mining	2122
Cement and Concrete Product Manufacturing	3273
Iron and Steel Mills and Ferroalloy Manufacturing	3311
Glass and Glass Product Manufacturing	3272
Basic Chemical Manufacturing	3251
Petroleum and Coal Products Manufacturing	3241
Pulp, Paper, and Paperboard Mills	3221
Solid Waste Combustors and Incinerators	562213

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this rule. This table lists the types of entities that the EPA is now aware could potentially be regulated by this rule. Other types of entities not listed in the table could also be regulated. To determine whether your EGU entity is regulated by this rule, you should carefully examine the applicability criteria found in 40 CFR 97.1004, which are unchanged in this rule. If you have questions regarding the applicability of this rule to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

B. What action is the Agency taking?

The EPA evaluated whether interstate ozone transport emissions from upwind states are significantly contributing to nonattainment, or interfering with maintenance, of the 2015 ozone NAAQS in any downwind state using the same 4-step interstate transport framework that was developed in previous ozone transport rulemakings. The EPA finds that emissions reductions are required from EGU and non-EGU sources in a total of 23 upwind states to eliminate significant contribution to downwind air quality problems for the 2015 ozone standard under the interstate transport provision of the CAA. The EPA will ensure that these NO_X emissions reductions are achieved by issuing FIP requirements for 23 states: Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin.

The EPA is revising the existing CSAPR Group 3 Trading Program to include additional states beginning in the 2023 ozone season. EGUs in three states not currently covered by any CSAPR trading program for seasonal NO_X emissions—Minnesota, Nevada, and Utah—will be added to the CSAPR Group 3 Trading Program under this rule. EGUs in twelve states currently participating in the Group 3 Trading Program will remain in the program under this rule: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. EGUs in seven states (Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin) will transition from the CSAPR Group 2 Trading Program to the CSAPR Group 3 Trading Program under this rule beginning in the 2023 ozone season. The EPA is establishing control stringency levels reflecting installation of state-of-the-art combustion controls on certain covered EGU sources in emissions budgets beginning in the 2024 ozone season. The EPA is establishing control stringency levels reflecting installation of new SCR or SNCR controls on certain covered EGU sources in emissions budgets beginning in the 2026 ozone season.

As a complement to the ozone season emissions budgets, the EPA is also establishing a backstop daily emissions rate of 0.14 lb/mmBtu for coal-fired steam units greater than or equal to 100 MW in covered states. The backstop emissions rate will first apply in 2024 for coal-fired steam sources with existing SCRs, and in the second control period in which a new SCR operates, but not later than 2030, for those currently without SCRs.

This rule establishes emissions limitations for non-EGU sources in 20 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. In these states, the EPA is establishing control requirements for the following unit types in non-EGU industries: reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; kilns in Cement and Cement Product Manufacturing; reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and combustors and incinerators in Solid Waste Combustors and Incinerators. *See* Table II.A–1 in this document for a list of NAICS codes for each entity included for regulation in this rule.

This rule reduces the transport of ozone precursor emissions to downwind areas, which is protective of human health and the environment because acute and chronic exposure to ozone are both associated with negative health impacts. Ozone exposure is also associated with negative effects on ecosystems. Additional information on the air quality issues addressed by this rule are included in section III of this document.

C. What is the Agency's legal authority for taking this action?

The statutory authority for this rule is provided by the CAA as amended (42 U.S.C. 7401 *et seq.*). Specifically, sections 110 and 301 of the CAA provide the primary statutory underpinnings for this rule. The most relevant portions of CAA section 110 are subsections 110(a)(1), 110(a)(2) (including 110(a)(2)(D)(i)(I)) and 110(c)(1)).

CAA section 110(a)(1) provides that states must make SIP submissions ''within 3 years (or such shorter period as the Administrator may prescribe) after the promulgation of a national primary ambient air quality standard (or any revision thereof),'' and that these SIP submissions are to provide for the ''implementation, maintenance, and enforcement'' of such NAAQS.[24] The statute directly imposes on states the duty to make these SIP submissions, and the requirement to make the submissions is not conditioned upon the EPA taking any action other than promulgating a new or revised NAAQS.[25]

The EPA has historically referred to SIP submissions made for the purpose of satisfying the applicable requirements of CAA sections 110(a)(1) and 110(a)(2) as ''infrastructure SIP'' or ''iSIP'' submissions. CAA section 110(a)(1) addresses the timing and general requirements for iSIP submissions, and CAA section 110(a)(2) provides more details concerning the required content of these submissions.[26] It includes a list of specific elements that ''[e]ach such plan'' must address.[27]

CAA section 110(c)(1) requires the Administrator to promulgate a FIP at any time within 2 years after the Administrator: (1) finds that a state has failed to make a required SIP submission; (2) finds a SIP submission to be incomplete pursuant to CAA section 110(k)(1)(C); or (3) disapproves a SIP submission. This obligation applies unless the state corrects the deficiency through a SIP revision that the Administrator approves before the FIP is promulgated.[28]

CAA section 110(a)(2)(D)(i)(I), also known as the ''good neighbor'' provision, provides the primary basis for this rule.[29] It requires that each state SIP include provisions sufficient to ''prohibit[ ], consistent with the provisions of this subchapter, any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—(I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any [NAAQS].'' [30] The EPA often refers to the emissions reduction requirements under this provision as ''good neighbor obligations'' and submissions addressing these requirements as ''good neighbor SIPs.''

[24] 42 U.S.C. 7410(a)(1).

[25] *See EPA* v. *EME Homer City Generation, L.P.*, 572 U.S. 489, 509–10 (2014).

[26] 42 U.S.C. 7410(a)(2).

[27] The EPA's general approach to infrastructure SIP submissions is explained in greater detail in individual notices acting or proposing to act on state infrastructure SIP submissions and in guidance. *See, e.g.,* Memorandum from Stephen D. Page on Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and 110(a)(2) (September 13, 2013).

[28] 42 U.S.C. 7410(c)(1).

[29] 42 U.S.C. 7410(a)(2)(D)(i)(I).

[30] *Id.*

Once the EPA promulgates a NAAQS, the EPA must designate areas as being in ''attainment'' or ''nonattainment'' of the NAAQS, or ''unclassifiable.'' CAA section 107(d).[31] For ozone, nonattainment is further split into five classifications based on the severity of the violation—Marginal, Moderate, Serious, Severe, or Extreme. Higher classifications provide states with progressively more time to attain while imposing progressively more stringent control requirements. *See* CAA sections 181, 182.[32] In general, states with nonattainment areas classified as Moderate or higher must submit plans to the EPA to bring these areas into attainment according to the statutory schedule. CAA section 182.[33] If an area fails to attain the NAAQS by the attainment date associated with its classification, it is ''bumped up'' to the next classification. CAA section 181(b).[34]

Section 301(a)(1) of the CAA gives the Administrator the general authority to prescribe such regulations as are necessary to carry out functions under the Act.[35] Pursuant to this section, the EPA has authority to clarify the applicability of CAA requirements and undertake other rulemaking action as necessary to implement CAA requirements. CAA section 301 affords the Agency any additional authority that may be needed to make certain other changes to its regulations under 40 CFR parts 52, 75, 78, and 97, to effectuate the purposes of the Act. Such changes are discussed in section IX of this document.

Tribes are not required to submit state implementation plans. However, as explained in the EPA's regulations outlining Tribal Clean Air Act authority, the EPA is authorized to promulgate FIPs for Indian country as necessary or appropriate to protect air quality if a tribe does not submit, and obtain the EPA's approval of, an implementation plan. *See* 40 CFR 49.11(a); *see also* CAA section 301(d)(4).[36] In the proposed rule, the EPA proposed an ''appropriate or necessary'' finding under CAA section 301(d) and proposed tribal FIP(s) as necessary to implement the relevant requirements. The EPA is finalizing these determinations, as further discussed in section III.C.2 of this document.

D. What actions has the EPA previously issued to address regional ozone transport?

The EPA has issued several previous rules interpreting and clarifying the requirements of CAA section 110(a)(2)(D)(i)(I) with respect to the regional transport of ozone. These rules, and the associated court decisions addressing these rules, summarized here, provide important direction regarding the requirements of CAA section 110(a)(2)(D)(i)(I).

The ''NO_X SIP Call,'' promulgated in 1998, addressed the good neighbor provision for the 1979 1-hour ozone NAAQS.[37] The rule required 22 states and the District of Columbia to amend their SIPs to reduce NO_X emissions that contribute to ozone nonattainment in downwind states. The EPA set ozone season NO_X budgets for each state, and the states were given the option to participate in a regional allowance trading program, known as the NO_X Budget Trading Program.[38] The D.C. Circuit largely upheld the NO_X SIP Call in *Michigan* v. *EPA,* 213 F.3d 663 (D.C. Cir. 2000), *cert. denied,* 532 U.S. 904 (2001).

The EPA's next rule addressing the good neighbor provision, CAIR, was promulgated in 2005 and addressed both the 1997 fine particulate matter ($PM_{2.5}$) NAAQS and 1997 ozone NAAQS.[39] CAIR required SIP revisions in 28 states and the District of Columbia to reduce emissions of sulfur dioxide (SO_2) or NO_X—important precursors of regionally transported $PM_{2.5}$ (SO_2 and annual NO_X) and ozone (summer-time NO_X). As in the NO_X SIP Call, states were given the option to participate in regional trading programs to achieve the reductions. When the EPA promulgated the final CAIR in 2005, the EPA also issued findings that states nationwide had failed to submit SIPs to address the requirements of CAA section 110(a)(2)(D)(i) with respect to the 1997 $PM_{2.5}$ and 1997 ozone NAAQS.[40] On March 15, 2006, the EPA promulgated FIPs to implement the emissions reductions required by CAIR.[41] CAIR was remanded to EPA by the D.C. Circuit in *North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir.), *modified on reh'g,* 550 F.3d 1176 (D.C. Cir. 2008). For more information on the legal issues underlying CAIR and the D.C. Circuit's holding in *North Carolina,* refer to the preamble of the CSAPR rule.[42]

In 2011, the EPA promulgated CSAPR to address the issues raised by the remand of CAIR. CSAPR addressed the two NAAQS at issue in CAIR and additionally addressed the good neighbor provision for the 2006 $PM_{2.5}$ NAAQS.[43] CSAPR required 28 states to reduce SO_2 emissions, annual NO_X emissions, or ozone season NO_X emissions that significantly contribute to other states' nonattainment or interfere with other states' abilities to maintain these air quality standards.[44] To align implementation with the applicable attainment deadlines, the EPA promulgated FIPs for each of the 28 states covered by CSAPR. The FIPs require EGUs in the covered states to participate in regional trading programs to achieve the necessary emissions reductions. Each state can submit a good neighbor SIP at any time that, if approved by EPA, would replace the CSAPR FIP for that state.

CSAPR was the subject of an adverse decision by the D.C. Circuit in August 2012.[45] However, this decision was reversed in April 2014 by the Supreme Court, which largely upheld the rule, including the EPA's approach to addressing interstate transport in CSAPR. *EPA* v. *EME Homer City Generation, L.P.,* 572 U.S. 489 (2014) (*EME Homer City I*). The rule was remanded to the D.C. Circuit to consider claims not addressed by the Supreme Court. *Id.* In July 2015 the D.C. Circuit

[31] 42 U.S.C. 7407(d).

[32] 42 U.S.C. 7511, 7511a.

[33] 42 U.S.C. 7511a.

[34] 42 U.S.C. 7511(b).

[35] 42 U.S.C. 7601(a)(1).

[36] 42 U.S.C. 7601(d)(4).

[37] *Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone,* 63 FR 57356 (Oct. 27, 1998). As originally promulgated, the NO_X SIP Call also addressed good neighbor obligations under the 1997 8-hour ozone NAAQS, but EPA subsequently stayed and later rescinded the rule's provisions with respect to that standard. *See* 84 FR 8422 (March 8, 2019).

[38] ''Allowance Trading,'' sometimes referred to as ''cap and trade,'' is an approach to reducing pollution that has been used successfully to protect human health and the environment. The design elements of the EPA's most recent trading programs are discussed in section VI.B.1.a of this document.

[39] *Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the* NO_X SIP Call, 70 FR 25162 (May 12, 2005).

[40] 70 FR 21147 (April 25, 2005).

[41] 71 FR 25328 (April 28, 2006).

[42] *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals,* 76 FR 48208, 48217 (August 8, 2011).

[43] 76 FR 48208.

[44] CSAPR was revised by several rulemakings after its initial promulgation to revise certain states' budgets and to promulgate FIPs for five additional states addressing the good neighbor obligation for the 1997 ozone NAAQS. *See* 76 FR 80760 (December 27, 2011); 77 FR 10324 (February 21, 2012); 77 FR 34830 (June 12, 2012).

[45] On August 21, 2012, the D.C. Circuit issued a decision in *EME Homer City Generation, L.P.* v. *EPA,* 696 F.3d 7 (D.C. Cir. 2012), vacating CSAPR. The EPA sought review with the D.C. Circuit *en banc* and the D.C. Circuit declined to consider the EPA's appeal *en banc. EME Homer City Generation, L.P.* v. *EPA,* No. 11–1302 (D.C. Cir. January 24, 2013), ECF No. 1417012 (denying EPA's motion for rehearing en banc).

generally affirmed the EPA's interpretation of various statutory provisions and the EPA's technical decisions. *EME Homer City Generation, L.P.* v. *EPA,* 795 F.3d 118 (2015) (*EME Homer City II*). However, the court remanded the rule without vacatur for reconsideration of the EPA's emissions budgets for certain states, which the court found may have over-controlled those states' emissions with respect to the downwind air quality problems to which the states were linked. *Id.* at 129–30, 138. For more information on the legal issues associated with CSAPR and the Supreme Court's and D.C. Circuit's decisions in the *EME Homer City* litigation, refer to the preamble of the CSAPR Update.[46]

In 2016, the EPA promulgated the CSAPR Update to address interstate transport of ozone pollution with respect to the 2008 ozone NAAQS.[47] The final rule updated the CSAPR ozone season NO_X emissions budgets for 22 states to achieve cost-effective and immediately feasible NO_X emissions reductions from EGUs within those states.[48] The EPA aligned the analysis and implementation of the CSAPR Update with the 2017 ozone season to assist downwind states with timely attainment of the 2008 ozone NAAQS.[49] The CSAPR Update implemented the budgets through FIPs requiring sources to participate in a revised CSAPR NO_X ozone season trading program beginning with the 2017 ozone season. As under CSAPR, each state could submit a good neighbor SIP at any time that, if approved by the EPA, would replace the CSAPR Update FIP for that state. The final CSAPR Update also addressed the remand by the D.C. Circuit of certain states' CSAPR phase 2 ozone season NO_X emissions budgets in *EME Homer City II.*

In December 2018, the EPA promulgated the CSAPR ''Close-Out,'' which determined that no further enforceable reductions in emissions of NO_X were required with respect to the 2008 ozone NAAQS for 20 of the 22 eastern states covered by the CSAPR Update.[50]

The CSAPR Update and the CSAPR Close-Out were both subject to legal challenges in the D.C. Circuit. *Wisconsin* v. *EPA,* 938 F.3d 303 (D.C. Cir. 2019) (*Wisconsin*); *New York* v. *EPA,* 781 Fed. App'x 4 (D.C. Cir. 2019) (*New York*). In September 2019, the D.C. Circuit upheld the CSAPR Update in virtually all respects but remanded the rule because it was partial in nature and did not fully eliminate upwind states' significant contribution to nonattainment or interference with maintenance of the 2008 ozone NAAQS by ''the relevant downwind attainment deadlines'' in the CAA. *Wisconsin,* 938 F.3d at 313–15. In October 2019, the D.C. Circuit vacated the CSAPR Close-Out on the same grounds that it remanded the CSAPR Update in *Wisconsin,* specifically because the Close-Out rule did not address good neighbor obligations by ''the next applicable attainment date'' of downwind states. *New York,* 781 Fed. App'x at 7.[51]

In response to the *Wisconsin* remand of the CSAPR Update and the *New York* vacatur of the CSAPR Close-Out, the EPA promulgated the Revised CSAPR Update on April 30, 2021.[52] The Revised CSAPR Update found that the CSAPR Update was a full remedy for nine of the covered states. For the 12 remaining states, the EPA found that their projected 2021 ozone season NO_X emissions would significantly contribute to downwind states' nonattainment or maintenance problems. The EPA issued new or amended FIPs for these 12 states and required implementation of revised emissions budgets for EGUs beginning with the 2021 ozone season. Based on the EPA's assessment of remaining air quality issues and additional emissions control strategies for EGUs and emissions sources in other industry sectors (non-EGUs), the EPA determined that the NO_X emissions reductions achieved by the Revised CSAPR Update fully eliminated these states' significant contributions to downwind air quality problems for the 2008 ozone NAAQS. As under the CSAPR and the CSAPR Update, each state can submit a good neighbor SIP at any time that, if approved by the EPA, would replace the Revised CSAPR Update FIP for that state.

On March 3, 2023, the D.C. Circuit Court of Appeals denied the Midwest Ozone Group's (MOG) petition for review of the Revised CSAPR Update. *MOG* v. *EPA,* No. 21–1146 (D.C. Cir. March 3, 2023). The court noted that it has ''exhaustively'' addressed the interstate transport framework before, citing relevant cases, and ''incorporate them herein by reference.'' Slip Op. 1 n.1. In response to MOG's arguments, the court upheld the Agency's air quality analysis. *Id.* at 10–11. The court noted that in light of the statutory timing framework and court-ordered schedule the EPA was under, the Agency's methodological choices were reasonable and provided ''an appropriately reliable projection of air quality conditions and contributions in 2021.'' *Id.* at 11–12.

III. Air Quality Issues Addressed and Overall Rule Approach

A. The Interstate Ozone Transport Air Quality Challenge

1. Nature of Ozone and the Ozone NAAQS

Ground-level ozone is not emitted directly into the air but is created by chemical reactions between NO_X and volatile organic compounds (VOCs) in the presence of sunlight. Emissions from electric utilities and industrial facilities, motor vehicles, gasoline vapors, and chemical solvents are some of the major sources of NO_X and VOCs.

Because ground-level ozone formation increases with temperature and sunlight, ozone levels are generally higher during the summer months. Increased temperature also increases emissions of volatile man-made and biogenic organics and can also indirectly increase NO_X emissions (*e.g.,* increased electricity generation for air conditioning).

On October 1, 2015, the EPA strengthened the primary and secondary ozone standards to 70 ppb as an 8-hour

[46] *Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS,* 81 FR 74504, 74511 (October 26, 2016).

[47] 81 FR 74504.

[48] One state, Kansas, was made newly subject to ozone season NO_X requirements by the CSAPR Update. All other CSAPR Update states were already subject to ozone season NO_X requirements under CSAPR.

[49] 81 FR 74516. The EPA's final 2008 Ozone NAAQS SIP Requirements Rule, 80 FR 12264, 12268 (March 6, 2015), revised the attainment deadline for ozone nonattainment areas designated as Moderate to July 20, 2018. *See* 40 CFR 51.1103. To demonstrate attainment by this deadline, states were required to rely on design values calculated using ozone season data from 2015 through 2017, since the July 20, 2018, deadline did not afford enough time for measured data of the full 2018 ozone season.

[50] *Determination Regarding Good Neighbor Obligations for the 2008 Ozone National Ambient Air Quality Standard,* 83 FR 65878, 65882 (December 21, 2018). After promulgating the CSAPR Update and before promulgating the CSAPR Close-Out, the EPA approved a SIP from Kentucky resolving the Commonwealth's good neighbor obligations for the 2008 ozone NAAQS. 83 FR 33730 (July 17, 2018). In the Revised CSAPR Update, the EPA made an error correction under CAA section 110(k)(6) to convert this approval to a disapproval, because the Kentucky approval relied on the same analysis which the D.C. Circuit determined to be unlawful in the CSAPR Close-Out.

[51] Subsequently, the D.C. Circuit made clear in a decision reviewing the EPA's denial of a petition under CAA section 126 that the holding in *Wisconsin* regarding alignment with downwind area's attainment schedules applies with equal force to the Marginal area attainment date established under CAA section 181(a). *See Maryland* v. *EPA,* 958 F.3d 1185, 1203–04 (D.C. Cir. 2020).

[52] *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS,* 86 FR 23054 (April 30, 2021).

level.[53] Specifically, the standards require that the 3-year average of the fourth highest 24-hour maximum 8-hour average ozone concentration may not exceed 70 ppb as a truncated value (*i.e.,* digits to right of decimal removed).[54] In general, areas that exceed the ozone standard are designated as nonattainment areas, pursuant to the designations process under CAA section 107(d), and are subject to heightened planning requirements depending on the severity of their nonattainment classification, *see* CAA sections 181, 182.

In the process of setting the 2015 ozone NAAQS, the EPA noted that the conditions conducive to the formation of ozone (*i.e.,* seasonally-dependent factors such as ambient temperature, strength of solar insolation, and length of day) differ by location, and that the Agency believes it is important that ozone monitors operate during all periods when there is a reasonable possibility of ambient levels approaching the level of the NAAQS. At that time, the EPA stated that ambient ozone concentrations in many areas could approach or exceed the level of the NAAQS, more frequently and during more months of the year compared with the historical ozone season monitoring lengths. Consequently, the EPA extended the ozone monitoring season for many locations. *See* 80 FR 65416 for more details.

Furthermore, the EPA stated that in addition to being affected by changing emissions, future ozone concentrations may also be affected by climate change. Modeling studies in the EPA's Interim Assessment (U.S. EPA, 2009a) that are cited in support of the 2009 Greenhouse Gas Endangerment Finding under CAA section 202(a) (74 FR 66496, Dec. 15, 2009) as well as a recent assessment of potential climate change impacts (Fann et al., 2015) project that climate change may lead to future increases in summer ozone concentrations across the contiguous U.S.[55] (80 FR 65300). The U.S. Global Change Research Program's *Impacts of Climate Change on Human Health in the United States: A Scientific Assessment*[56] and *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II*[57] reinforced these findings. The increase in ozone results from changes in local weather conditions, including temperature and atmospheric circulation patterns, as well as changes in ozone precursor emissions that are influenced by meteorology (Nolte et al., 2018). While the projected impact may not be uniform, climate change has the potential to increase average summertime ozone relative to a future without climate change.[58 59 60] Climate change has the potential to offset some of the improvements in ozone air quality, and therefore some of the improvements in public health, that are expected from reductions in emissions of ozone precursors (80 FR 65300). The EPA responds to comments received on the impacts of climate change on ozone formation in section 11 of the *Response to Comments* (*RTC*) document.

2. Ozone Transport

Studies have established that ozone formation, atmospheric residence, and transport occur on a regional scale (*i.e.,* thousands of kilometers) over much of the U.S.[61] While substantial progress has been made in reducing ozone in many areas, the interstate transport of ozone precursor emissions remains an important contributor to peak ozone concentrations and high-ozone days during the summer ozone season.

The EPA has previously concluded in the NO_X SIP Call, CAIR, CSAPR, the CSAPR Update, and the Revised CSAPR Update that a regional NO_X control strategy would be effective in reducing regional-scale transport of ozone precursor emissions. NO_X emissions can be transported downwind as NO_X or as ozone after transformation in the atmosphere. In any given location, ozone pollution levels are impacted by a combination of background ozone concentration, local emissions, and emissions from upwind sources resulting from ozone transport, in conjunction with variable meteorological conditions. Downwind states' ability to meet health-based air quality standards such as the NAAQS is challenged by the transport of ozone pollution across state borders. For example, ozone assessments conducted for the October 2015 Regulatory Impact Analysis of the Final Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone[62] continue to show the importance of NO_X emissions for ozone transport. This analysis is included in the docket for this rulemaking.

Further, studies have found that EGU NO_X emissions reductions can be effective in reducing individual 8-hour peak ozone concentrations and in reducing 8-hour peak ozone concentrations averaged across the ozone season. For example, a study of the EGU NO_X reductions achieved under the NO_X Budget Trading Program (*i.e.,* the NO_X SIP Call) shows that regulating NO_X emissions in that program was highly effective in reducing ozone concentrations during the ozone season.[63]

Previous regional ozone transport efforts, including the NO_X SIP Call, CAIR, CSAPR, the CSAPR Update, and the Revised CSAPR Update, required ozone season NO_X reductions from EGU sources to address interstate transport of ozone. Together with NO_X, the EPA has also identified VOCs as a precursor in forming ground-level ozone. Ozone formation chemistry can be ''NO_X-limited,'' where ozone production is primarily determined by the amount of NO_X emissions or ''VOC-limited,'' where ozone production is primarily

[53] 80 FR 65291.

[54] 40 CFR part 50, appendix P.

[55] These modeling studies are based on coupled global climate and regional air quality models and are designed to assess the sensitivity of U.S. air quality to climate change. A wide range of future climate scenarios and future years have been modeled and there can be variations in the expected response in U.S. O3 by scenario and across models and years, within the overall signal of higher summer O3 concentrations in a warmer climate.

[56] U.S. Global Change Research Program (USGCRP), 2016: *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment.* Crimmins, A., J. Balbus, J.L. Gamble, C.B. Beard, J.E. Bell, D. Dodgen, R.J. Eisen, N. Fann, M.D. Hawkins, S.C. Herring, L. Jantarasami, D.M. Mills, S. Saha, M.C. Sarofim, J. Trtanj, and L. Ziska, Eds. U.S. Global Change Research Program, Washington, DC, 312 pp. *https://dx.doi.org/10.7930/J0R49NQX.*

[57] USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II* [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.

[58] Fann NL, Nolte CG, Sarofim MC, Martinich J, Nassikas NJ. Associations Between Simulated Future Changes in Climate, Air Quality, and Human Health. JAMA Netw Open. 2021;4(1):e2032064. doi:10.1001/jamanetworkopen.2020.32064

[59] Christopher G Nolte, Tanya L Spero, Jared H Bowden, Marcus C Sarofim, Jeremy Martinich, Megan S Mallard. Regional temperature-ozone relationships across the U.S. under multiple climate and emissions scenarios. J Air Waste Manag Assoc. 2021 Oct;71(10):1251–1264. doi: 10.1080/10962247.2021.1970048.

[60] Nolte, C.G., P.D. Dolwick, N. Fann, L.W. Horowitz, V. Naik, R.W. Pinder, T.L. Spero, D.A. Winner, and L.H. Ziska, 2018: Air Quality. In Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 512–538. doi: 10.7930/NCA4.2018.CH13

[61] Bergin, M.S. et al. (2007) Regional air quality: Local and interstate impacts of NO_X and SO_2 emissions on ozone and fine particulate matter in the eastern United States. Environmental Sci & Tech. 41: 4677–4689.

[62] Available in the docket for the October 2015 Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone at *https://www.regulations.gov/docket/EPA-HQ-OAR-2008-0699.*

[63] Butler, et al., ''Response of Ozone and Nitrate to Stationary Source Reductions in the Eastern USA.'' *Atmospheric Environment,* 2011.

determined by the amount of VOC emissions.[64] The EPA and others have long regarded NO_X to be the more significant ozone precursor in the context of interstate ozone transport.[65]

The EPA has determined that the regulation of VOCs as an ozone precursor is not necessary to eliminate significant contribution of ozone transport to downwind areas in this rule. As described in section V.A of this document, the EPA examined the results of the contribution modeling performed for this rule to identify the portion of the ozone contribution attributable to anthropogenic NO_X emissions versus VOC emissions from each linked upwind state to each downwind receptor. Our analysis of the ozone contribution from upwind states subject to regulation demonstrates that regional ozone concentrations affecting the vast majority of the downwind areas of air quality concern are NO_X-limited, rather than VOC-limited. Therefore, the rule's strategy for reducing regional-scale transport of ozone targets NO_X emissions from stationary sources to achieve the most effective reductions of ozone transport over the geography of the affected downwind areas. The potential impacts of NO_X mitigation strategies from other sources are discussed in section V.B of this document.

In section V of this document, the EPA describes the multi-factor test that is used to determine NO_X emissions reductions that are cost-effective and reduce interstate transport of ground-level ozone. Our analysis indicates that the EGU and non-EGU control requirements included in this rule will provide meaningful improvements in air quality at the downwind receptors. Based on the implementation schedule established in section VI.A of this document, the EPA finds that the regulatory requirements included in the rule are as expeditious as practicable and are aligned with the attainment schedule of downwind areas.

3. Health and Environmental Effects

Exposure to ambient ozone causes a variety of negative effects on human health, vegetation, and ecosystems. In humans, acute and chronic exposure to ozone is associated with premature mortality and certain morbidity effects, such as asthma exacerbation. In ecosystems, ozone exposure causes visible foliar injury, decreases plant growth, and affects ecosystem community composition. *See* EPA's October 2015 Regulatory Impact Analysis of the Final Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone[66] in the docket for this rulemaking for more information on the human health and ecosystem effects associated with ambient ozone exposure.

Commenters on prior ozone transport rules have asserted that VOC emissions harm underserved and overburdened communities experiencing disproportionate environmental health burdens and facing other environmental injustices. The EPA acknowledges that VOCs can contain toxic chemicals that are detrimental to public health. The EPA conducted a demographic analysis as part of the regulatory impact analysis for the 2015 revisions to the primary and secondary ozone NAAQS. This analysis, which is included in the docket for this rulemaking, found greater representation of minority populations in areas with poor air quality relative to the revised ozone standard than in the U.S. as a whole. The EPA concluded that populations in these areas would be expected to benefit from implementation of future air pollution control actions from state and local air agencies in implementing the strengthened standard. This rule is an example of air pollution control actions implemented by the Federal Government in support of the more protective 2015 ozone NAAQS, and populations living in downwind ozone nonattainment and maintenance areas are expected to benefit from improved air quality that will result from reducing ozone transport. Further discussion of the environmental justice analysis of this rule is located in section VII of this document and in the accompanying regulatory impact analysis, titled ''Regulatory Impact Analysis for Final Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard'' [EPA–452/D–22–001], which is available in the docket for this rulemaking.

The Agency regulates exposure to toxic pollutant concentrations and ambient exposure to criteria pollutants other than ozone through other sections of the Act, such as the regulation of hazardous air pollutants under CAA section 112 or the process for revising and implementing the NAAQS under CAA sections 107–110. The purpose of the subject rulemaking is to protect public health and the environment by eliminating significant contribution from 23 states to nonattainment or maintenance of the 2015 ozone NAAQS to meet the requirements of the CAA's interstate transport provision. In this rule, the EPA continues to observe that requiring NO_X emissions reductions from stationary sources is an effective strategy for reducing regional ozone transport in the U.S.

The EPA responds to other comments received on the health and environmental impacts of ozone exposure in section 11 of the *RTC* document.

B. Final Rule Approach

1. The 4-Step Interstate Transport Framework

The EPA first developed a multi-step process to address the requirements of the good neighbor provision in the 1998 NO_X SIP Call and the 2005 CAIR. The Agency built upon this framework and further refined the methodology for addressing interstate transport obligations in subsequent rules such as CSAPR in 2011, the CSAPR Update in 2016, and the Revised CSAPR Update in 2021.[67] In CSAPR, the EPA first articulated a ''4-step framework'' within which to assess interstate transport obligations for ozone. In this rule to address interstate transport obligations for the 2015 ozone NAAQS, the EPA is again utilizing the 4-step interstate transport framework. These steps are: (1) identifying downwind receptors that are expected to have problems attaining the NAAQS (nonattainment receptors) or maintaining the NAAQS (maintenance receptors); (2) determining which upwind states are ''linked'' to these identified downwind receptors based on a numerical contribution threshold; (3) for states linked to downwind air quality problems, identifying upwind emissions on a statewide basis that significantly contribute to downwind nonattainment or interfere with downwind maintenance of the NAAQS, considering cost- and air quality-based factors; and (4) for upwind states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in any downwind state, implementing the necessary emissions reductions through enforceable measures.

Comment: The EPA received comments supporting the Agency's use of the 4-step interstate transport framework as a permissible method for assigning the required amount of

[64] ''Ozone Air Pollution.'' *Introduction to Atmospheric Chemistry,* by Daniel J. Jacob, Princeton University Press, Princeton, New Jersey, 1999, pp. 231–244.

[65] 81 FR 74514.

[66] Available at *https://www.epa.gov/sites/default/files/2016-02/documents/20151001ria.pdf.*

[67] *See* CSAPR, Final Rule, 76 FR 48208, 48248–48249 (August 8, 2011); CSAPR Update, Final Rule, 81 FR 74504, 74517–74521 (October 26, 2016).

emissions reductions necessary to eliminate upwind states' significant contribution. Commenters also noted that the 4-step interstate transport framework was reviewed by the Supreme Court in *EPA vs. EME Homer City Generation,* 572 U.S. 489 (2014), and upheld. However, other commenters took exception to the overall approach of this proposed action. These commenters alleged that the EPA is ignoring the ''flexibility'' in addressing good neighbor obligations that it had purportedly suggested to states would be permissible in memoranda that the EPA issued in 2018. Commenters also raised concerns that the air quality modeling (2016v2) the EPA used to propose to disapprove SIP submittals and as the basis for the proposed FIP was not available to states at the time they made their submissions and that the changes in results at Steps 1 and 2 from prior rounds of modeling rendered the new modeling unreliable. Commenters also raised a number of arguments that the EPA should allow states an additional opportunity to submit SIPs before promulgating a FIP, advocated that the EPA should issue a ''SIP call'' under CAA section 110(k)(5), asked for the EPA to issue new or more specific guidance, or otherwise suggested that the EPA should defer acting to promulgate a FIP at this time.

Response: As an initial matter, comments regarding the EPA's basis for disapproving SIPs are beyond the scope of this action.[68] To the extent these comments relate to the legal basis for the EPA to promulgate a FIP, the EPA disagrees that it is acting in a manner contrary to the memoranda it released in 2018 related to good neighbor obligations for the 2015 ozone NAAQS. Arguments that the EPA must or should allow states to re-submit SIP submissions based on the most recent modeling information before the EPA promulgates a FIP ignore the plain language of the statute and relevant caselaw. CAA section 110(c) authorizes the EPA to promulgate a FIP ''at any time within 2 years'' of a SIP disapproval. No provision of the Act requires the EPA to give states an additional opportunity to prepare a new SIP submittal once the EPA has proposed a FIP or proposed disapproval of a SIP submittal. Comments regarding the timing of the EPA's actions and calls for the EPA to allow time for states to resubmit SIPs are further addressed in *RTC* sections 1.1 and 2.4.

With regard to the need for the EPA to develop and issue guidance in addressing good neighbor obligations, in *EPA* v. *EME Homer City Generation, L.P.,* the Supreme Court held that ''nothing in the statute places the EPA under an obligation to provide specific metrics to States before they undertake to fulfill their good neighbor obligations.'' [69] While we have taken a different approach in some prior rulemakings by providing states with an opportunity to submit a SIP after we quantified the states' budgets (*e.g.,* the NO_X SIP Call and CAIR [70]), the CAA does not require such an approach.

2018 Memoranda. As commenters point out, the EPA issued three ''memoranda'' in 2018 to provide some assistance to states in developing these SIP submittals.[71] Each memorandum made clear that the EPA's action on SIP submissions would be through a separate notice-and-comment rulemaking process and that SIP submissions seeking to rely on or take advantage of any so-called ''flexibilities'' in these memoranda would be carefully reviewed against the relevant legal requirements and technical information available to the EPA at the time it would take such rulemaking action. Further, certain aspects of discussions in those memoranda were specifically identified as not constituting agency guidance (especially Attachment A to the March 2018 memorandum, which comprised an unvetted list of external stakeholders' ideas). And, although outside the scope of this action, as the EPA has explained in disapproving states' SIP submittals, those submittals did not meet the terms of the August 2018 or October 2018 memoranda addressing contribution thresholds and maintenance receptors, respectively.

Commenters mistakenly view Attachment A to the March 2018 memorandum as constituting agency guidance. This memorandum was primarily issued to share modeling results for 2023 that represented the best information available to the Agency as of March 2018, while Attachment A then listed certain ideas from certain stakeholders that the EPA said could be further discussed among states and stakeholders. The EPA disagrees with commenters' characterization of the EPA's stance regarding these so-called ''flexibilities'' listed (without analysis) in Attachment A. The March 2018 memorandum provided, ''While the information in this memorandum and the associated air quality analysis data could be used to inform the development of these SIPs, the information is not a final determination regarding states' obligations under the good neighbor provision.'' The EPA again affirms that the concepts listed in Attachment A to the March 2018 memorandum require unique consideration, and these ideas do not constitute agency guidance with respect to transport obligations for the 2015 ozone NAAQS. Attachment A to the March 2018 memorandum identified a ''Preliminary List of Potential Flexibilities'' that could potentially inform SIP development. However, the EPA made clear in both the March 2018 memorandum [72] and in Attachment A that the list of ideas was not endorsed by the Agency but rather ''comments provided in various forums'' on which the EPA sought ''feedback from interested stakeholders.'' [73] Further, Attachment A stated, ''EPA is not at this time making any determination that the ideas discussed below are consistent with the requirements of the CAA, nor are we specifically recommending that states use these approaches.'' [74] Attachment A to the March 2018 memorandum, therefore, does not

[68] We nonetheless further respond to comments regarding the timing and sequence of the EPA's SIP and FIP actions, the relevance of judicial consent decrees, the requests for a SIP call, and related comments—to the extent any of these issues are within scope of the present action—in Sections 1 and 2 of the *RTC* document located in the docket for this action.

[69] 572 U.S. 489, 510 (2014). ''Nothing in the Act differentiates the Good Neighbor Provision from the several other matters a State must address in its SIP. Rather, the statute speaks without reservation: Once a NAAQS has been issued, a State 'shall' propose a SIP within three years, § 7410(a)(1), and that SIP 'shall' include, among other components, provisions adequate to satisfy the Good Neighbor Provision, § 7410(a)(2).'' *EPA* v. *EME Homer City Generation, L.P.,* 572 U.S. at 515.

[70] For information on the NO_X SIP call see 63 FR 57356 (October 27, 1998). For information on CAIR *see* 70 FR 25162 (May 12, 2005).

[71] *See* Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I) (March 27, 2018) (''March 2018 memorandum''); Analysis of Contribution Thresholds for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards, August 31, 2018) (''August 2018 memorandum''); Considerations for Identifying Maintenance Receptors for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards, October 19, 2018 (''October 2018 memorandum''). These are available in the docket or at *https://www.epa.gov/airmarkets/memo-and-supplemental-information-regarding-interstate-transport-sips-2015-ozone-naaqs.*

[72] ''In addition, the memorandum is accompanied by Attachment A, which provides a preliminary list of potential flexibilities in analytical approaches for developing a good neighbor SIP that may warrant further discussion between EPA and states.'' March 2018 memorandum at 1.

[73] March 2018 memorandum, Attachment A at A–1.

[74] *Id.*

constitute agency guidance, but was intended to generate further discussion around potential approaches to addressing ozone transport among interested stakeholders. The EPA emphasized in these memoranda that such alternative approaches must be technically justified and appropriate in light of the facts and circumstances of each particular state's submittal. To the extent states sought to develop or rely on one or more of these ideas in support of their SIP submissions, the EPA reviewed their technical and legal justifications for doing so.[75]

Regarding the October 2018 memorandum, that document recognized that states may be able to demonstrate in their SIPs that conditions exist that would justify treating a monitoring site as not being a maintenance receptor despite results from our modeling methodology identifying it as such a receptor. The EPA explained that this demonstration could be appropriate under two circumstances: (1) the site currently has ''clean data'' indicating attainment of the 2015 ozone NAAQS based on measured air quality concentrations, or (2) the state believes there is a technical reason to justify using a design value from the baseline period that is lower than the maximum design value based on monitored data during the same baseline period. To justify such an approach, the EPA anticipated that any such showing would be based on an analytical demonstration that (1) meteorological conditions in the area of the monitoring site were conducive to ozone formation during the period of clean data or during the alternative base period design value used for projections; (2) ozone concentrations have been trending downward at the site since 2011 (and ozone precursor emissions of NO_X and VOC have also decreased); and (3) emissions are expected to continue to decline in the upwind and downwind states out to the attainment date of the receptor. Although this is beyond the scope of this action, the EPA explained in its final SIP disapproval action that no state successfully demonstrated that one of these alternative approaches is justified. In this action, our analysis of the air quality data and projections in section IV of this document indicate that trends in historic measured data do not necessarily support adopting a less stringent approach for identifying maintenance receptors for purposes of the 2015 ozone NAAQS. In fact, as explained in section III.B.1.a and IV.D of this document, the EPA has found in its analysis for this final rule that, in general, recent measured data from regulatory ambient air quality ozone monitoring sites suggest that a number of receptors with elevated ozone levels will persist in 2023 even though our traditional methodology at Step 1 did not identify these monitoring sites as receptors in 2023. Thus, the EPA is not acting inconsistently with that memorandum—the factual conditions that would need to exist for the suggested approaches of that memorandum to be applicable have not been demonstrated as being applicable or appropriate based on the relevant data.

Regarding the August 2018 memorandum, as discussed in section IV.F.2 of this document, for purposes of Step 2 of our ozone transport evaluation framework, we are applying a 1 percent of NAAQS threshold rather than a 1 ppb threshold, as this memorandum had suggested might be appropriate for states to apply as an alternative. The EPA is finalizing its proposed approach of consistently using a 1 percent of the NAAQS contribution threshold at Step 2 to evaluate whether states are linked to downwind nonattainment and maintenance concerns for purposes of this FIP.

The approach of this FIP ensures both national consistency across all states and consistency and continuity with our prior interstate transport actions for other NAAQS. Further, in this action the EPA is promulgating FIPs under the authority of CAA section 110(c). In doing so, the EPA has exercised its discretion to determine how to define and apply good neighbor obligations in place of the discretion states otherwise would exercise (subject to the EPA's approval as compliant with the Act). In general, the EPA is applying the 4-step interstate transport framework it devised over the course of its prior good neighbor rulemakings, including applying a consistent definition of nonattainment and maintenance-only receptors, and applying the 1 percent of NAAQS threshold at Step 2. The basis for these decisions is further explained in sections IV.F.1 and IV.F.2 of the document. These policy judgments reflect consistency with relevant good neighbor case law and past agency practice implementing the good neighbor provision as reflected in the original CSAPR, CSAPR Update, Revised CSAPR Update, and related rulemakings. Nationwide consistency in approach is particularly important in the context of interstate ozone transport, which is a regional-scale pollution problem involving the collective emissions of many smaller contributors. Effective policy solutions to the problem of interstate ozone transport dating back to the NO_X SIP Call (63 FR 57356 (October 27, 1998)) have necessitated the application of a uniform framework of policy judgments, and the EPA's framework applied here has been upheld as ensuring an ''efficient and equitable'' approach. *See EME Homer City Generation, LP* v. *EPA,* 572 U.S. 489, 519 (2014).

Updated modeling. The EPA had originally provided 2023 modeling results in its March 2018 memorandum, which used a 2011-based platform. Many states used this modeling in providing good neighbor SIP submittals for the 2015 ozone NAAQS. While our action on the SIP submittals is not within scope of this action, commenters claim the use of new modeling or other information not available to states at the time they made their submittals renders this action promulgating a FIP unlawful. Notwithstanding whether that is an accurate characterization of the EPA's basis for disapproving the SIPs, we note that the court in *Wisconsin* rejected this precise argument against the CSAPR Update FIPs as a collateral attack on the SIP disapprovals. 938 F.3d at 336 (''That is the hallmark of an improper collateral attack. The true gravamen of the claim lies in the agency's failure to timely act upon the States' SIP submissions and, relatedly, its reliance on data compiled after the SIP action deadline. Both go directly to the legitimacy of the SIP denials.'').

Nonetheless, we offer the following explanation of the evolution of the EPA's understanding of projected air quality conditions and contributions in 2023 resulting from the iterative nature of our modeling efforts. These modeling efforts are further addressed in section IV of this document. We acknowledge that to evaluate transport SIPs and support our proposed FIP the EPA reassessed receptors at Step 1 and states' contribution levels at Step 2 through additional modeling (2016v2) before proposing this action and have reassessed again to inform the final action (2016v3). At proposal, we relied on CAMx Version 7.10 and the 2016v2 emissions platform to make updated determinations regarding which receptors would likely exist in 2023 and which states are projected to contribute above the contribution threshold to those receptors. As explained in the preamble of the EPA's proposed FIP and further detailed in the ''Air Quality

[75] *E.g.*, 87 FR 64423–64425 (Alabama); 87 FR 31453–31454 (California); 87 FR 9852–9854 (Illinois); 87 FR 9859–9860 (Indiana); 87 FR 9508, 9515 (Kentucky); 87 FR 9861–9862 (Michigan); 87 FR 9869–9870 (Ohio); 87 FR 9798, 9818–9820 (Oklahoma); 87 FR 31477–31481 (Utah); 87 FR 9526–9527 (West Virginia).

Modeling Technical Support Document for the Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards Proposed Rulemaking'' (Dec. 2021), hereinafter referred to as Air Quality Modeling Proposed Rule TSD, and the ''Technical Support Document (TSD): Preparation of Emissions Inventories for the 2016v2 North American Emissions Modeling Platform'' (Dec. 2021), hereinafter referred to as the 2016v2 Emissions Inventory TSD, both available in the docket for this action (docket ID no. EPA–HQ–OAR–2021–0668), this modeling built off of previous modeling iterations used to support the EPA's action on interstate transport obligations. The EPA periodically refines its modeling to ensure the results are as indicative as possible of air quality in future years. This includes making any necessary adjustments to our modeling platform and updating our emissions inventories to reflect current information, including information submitted during public comments on proposed actions.

For this final rule, the EPA has evaluated a raft of technical information and critiques of its 2016v2 modeling provided by commenters on this action (as well as comments on the SIP actions) and has responded to those comments and incorporated updates into the version of the modeling used to support this final rule (2016v3). As explained in section IV.B of the document, in response to additional information provided by stakeholders following a solicitation of feedback during the release of the 2016v2 emissions inventory and during the comment periods on the proposed SIP actions, the EPA has reviewed and revised its 2016v2 modeling platform and input since the platform was made available for comment. The new modeling platform 2016v3 was developed from this input, and the modeling results using platform 2016v3 are available with this action. *See* section IV of this document for further discussion. Thus, the EPA's final rule is based on a comprehensive record of data and technical evaluation, including the updated modeling information used at proposal (2016v2), the comments received on that modeling, and the latest modeling used in this final rule (2016v3).

The changes in projected outcomes at Steps 1 and 2 are a product of these changes; these updates between the data released in 2018 to now are an outgrowth of this iterative process, including updating the platform from a 2011 to a 2016 base year, updates to the emissions inventory information and other updates. It is reasonable for the Agency to improve its understanding of a situation before taking final action, and the Agency uses the best information available to it in taking this action.

Further, these modeling updates have not uniformly resulted in new linkages—the 2016v2 modeling, for instance, corroborated the proposed approval of Montana and supported approval of Colorado's SIP in October of 2022.[76] Although some commenters indicate that our modeling iterations have provided differing outcomes and are therefore unreliable, this is not what the overall record indicates. Rather, in general, although the specifics of states' linkages may have changed to some extent, our modeling on the whole has provided consistent outcomes regarding which states are linked to downwind air quality problems. For example, the EPA's modeling shows that most states that were linked to one or more receptors using the 2011-based platform (*i.e.,* the March 2018 data release) are also linked to one or more receptors using the newer 2016-based platform. Because the new platform uses different meteorology (*i.e.,* 2016 instead of 2011), it is not unexpected that an upwind state would be linked to different receptors using 2011 versus 2016 meteorology. In addition, although a state may be linked to a different set of receptors, those receptors are within the same areas that have historically had a persistent air quality problem. Only three upwind states included in the FIP went from being unlinked to being linked in 2023 between the 2011-based modeling provided in the March 2018 memorandum and the 2016v3-based modeling—Alabama, Minnesota, and Nevada.

Additionally, we disagree with commenters who claim that the 2016v2 modeling results were sprung upon the states with the publication of the proposed SIP disapprovals. In fact, states had prior access to a series of data and modeling releases beginning as early as the publication of the 2016v1 modeling with the proposed Revised CSAPR Update in October 2020. States could have reviewed and used this technical information to understand and track how the EPA's modeling updates were affecting the list of potential receptors and linkages for the 2015 ozone NAAQS in the 2023 analytic year.

The 2016-based meteorology and boundary conditions used in the modeling have been available through the 2016v1 platform, which was used for the Revised CSAPR Update (proposed, 85 FR 68964; October 30, 2020). The updated emissions inventory files used in the current modeling were publicly released September 21, 2021, for stakeholder feedback, and have been available on our website since that time.[77] The CAMx modeling software that the EPA used has likewise been publicly available for over a year before this final rule was proposed on April 6, 2022. CAMx version 7.10 was released by the model developer, Ramboll, in December 2020. On January 19, 2022, we released on our website and notified a wide range of stakeholders of the availability of both the modeling results for 2023 and 2026 (including contribution data) along with many key underlying input files.[78]

By providing the 2016 meteorology and boundary conditions (used in the 2016v1 version) in fall of 2020, and by releasing updated emissions inventory information used in 2016v2 in September of 2021,[79] we gave states and other interested parties multiple opportunities prior to proposal of this rule on April 6, 2022, to consider how our modeling updates could affect their status for purposes of evaluating potential linkages for the 2015 ozone NAAQS. In this final rule, we have updated our modeling to 2016v3, incorporating and reflecting the feedback and additional information we received through the multiple public comment opportunities the EPA made available on the 2016v2 modeling.

The EPA's development of and reliance on newer modeling is reasonable and is simply another iteration of the EPA's longstanding scientific and technical work to improve our understanding of air quality issues and causes going back many decades.

Comment: Commenters asserted that the EPA lacks authority under the good neighbor provision to do more than establish state-wide emissions budgets, which states may then implement through their own choice of emissions controls. The commenters claim that the EPA lacks authority to directly regulate emissions sources under the good neighbor provision, and they cite to case law that they view as establishing a ''federalism bar'' to direct Federal regulation. Commenters assert that the

[76] 87 FR 6095, 6097 at n. 15 (February 3, 2022) (Montana proposal); 87 FR 27050, 27056 (May 6, 2022) (Colorado, proposal), 87 FR 61249 (October 11, 2022) (Colorado, final).

[77] *See https://www.epa.gov/air-emissions-modeling/2016v2-platform.*

[78] *See https://www.epa.gov/scram/photochemical-modeling-applications.*

[79] *https://www.epa.gov/air-emissions-modeling/2016v2-platform.*

term ''amounts'' as used in the good neighbor provision prevents the agency from establishing emissions limits at individual sources, such as the non-EGU industrial units that the EPA proposed to regulate or implementing ''enhancements'' in its mass-based emissions trading approach for EGUs as it had proposed. Commenters claim these aspects of the rule are an unlawful or arbitrary and capricious departure from the EPA's prior transport rulemakings, which they claim only set mass-based emissions budgets as the means to eliminate ''significant contribution.''

Response: To the extent these comments challenge the EPA's disapproval of states' 2015 ozone NAAQS good neighbor SIP submissions, they are out of scope of this action, which promulgates a FIP under the authority of CAA section 110(c)(1). To the extent commenters assert that the EPA does not have the authority to directly implement source-specific emissions control requirements or other emissions control measures, means, or techniques, including emissions trading programs, in the exercise of that FIP authority, the EPA disagrees. While the courts have long recognized that the states have wide discretion in the design of SIPs to attain and maintain the NAAQS, *see, e.g., Union Electric Co* v. *EPA,* 427 U.S. 246 (1976), when the EPA promulgates a FIP to cure a defective SIP, the Act, including the definition of a FIP in section 302(y), provides for the EPA to directly implement the Act's requirements. The EPA is granted authority to choose among a broad range of ''emission limitations or other control measures, means, or techniques (including economic incentives, such as marketable permits or auctions of emissions allowances) . . . .'' CAA section 302(y); *see also* CAA section 110(a)(2) (empowering states to implement an identical set of emissions control mechanisms).

The courts have also recognized that the EPA has broad authority to cure a defective SIP, that the EPA may exercise its own, independent regulatory authority in implementing a FIP in accordance with the CAA, and that the EPA in effect steps into the shoes of a state when it promulgates a FIP. *See, e.g., Central Ariz. Water Conservation Dist.* v. *EPA,* 990 F.2d 1531 (9th Cir. 1993); *South Terminal Corp.* v. *EPA,* 504 F.2d 646 (1st Cir. 1974). *Accord Virginia* v. *EPA,* 108 F.3d 1397, 1406–07 (D.C. Cir. 1997) (''The Federal Plan 'provides an additional incentive for state compliance because it rescinds state authority to make the many sensitive and policy choices that a pollution control regime demands.''') (quoting *Natural Resources Defense Council* v. *Browner,* 57 F.3d 1122, 1124 (D.C. Cir. 1995)). *Cf. District of Columbia* v. *Train,* 521 F.2d 971 (D.C. Cir. 1975), *vacated sub nom. EPA* v. *Brown,* 431 U.S. 99 (1977) (''[W]here cooperation [from states] is not forthcoming, we believe that the recourse contemplated by the commerce clause is direct federal regulation of the offending activity . . . .'').

These same principles apply where the EPA must promulgate a FIP to address good neighbor requirements under CAA section 110(a)(2)(D)(i)(I). The EPA has promulgated a series of FIPs in the past to address the relevant requirements for prior ozone and PM NAAQS. *See, e.g.,* CAIR FIP, 71 FR 25328 (April 28, 2006); CSAPR, 76 FR 48208 (August 8, 2011); the CSAPR Update, 81 FR 74504 (October 26, 2016); and the Revised CSAPR Update, 86 FR 23054 (April 30, 2021). Courts have upheld the EPA's exercise of this authority. *See EME Homer City Generation* v. *EPA,* 572 U.S. 489 (2014); *Wisconsin* v. *EPA,* 938 F.3d 303 (D.C. Cir. 2019). Indeed, in *EME Homer City,* the U.S. Supreme Court held that the EPA is not obligated to provide guidance to states before acting on their good neighbor submissions or give states a second chance at correcting the deficiencies before promulgating a FIP, and the EPA may promulgate a FIP at any time after finalizing its disapproval of SIP submissions. 572 U.S. at 508–11.

The cases cited by commenters, which they refer to as establishing the *Train-Virginia* federalism bar, were not reviewing the exercise of the EPA's authority in promulgating a FIP under CAA section 110(c)(1) but rather were describing the scope of the EPA's authority in acting on SIP submissions under CAA section 110(k)(3) or in issuing a ''SIP call'' under section 110(k)(5). In those latter contexts, the courts have held that the EPA may not dictate the specific control measures states must implement to meet the Act's requirements. *See Virginia,* 108 F.3d at 1409–10. In *Michigan,* the D.C. Circuit upheld the EPA's exercise of CAA section 110(k)(5) authority in issuing the ''NO_X SIP Call,'' because, ''EPA does not tell the states how to achieve SIP compliance. Rather, EPA looks to section 110(a)(2)(D) and merely provides the levels to be achieved by state-determined compliance mechanisms. . . . However, EPA made clear that states do not have to adopt the control scheme that EPA assumed for budget-setting purposes.'' *Michigan* v. *EPA,* 213 F.3d 663, 687–88 (D.C. Cir. 2000).

Commenters' position that the EPA must provide similar flexibility to the states in this action (*i.e.,* only provide a general emissions reduction target and leave to states how to meet that target) is a non sequitur. The EPA is implementing a FIP in this action and *must* directly implement the necessary emissions controls. The EPA is not empowered to require states to implement FIP mandates. Such an approach would conflict with constitutional anti-commandeering principles, is not provided for in the Act, and would only constitute a partial implementation of FIP obligations in contravention of the holding in *Wisconsin* v. *EPA,* 938 F.3d at 313–20.

Commenters' attempt to contrast the implementation of source-specific emissions limitations at industrial sources with the establishment of a specific mass-based budget (as the EPA has set for power plants in prior good neighbor FIPs) is unavailing. CAA section 110(c)(1) and 302(y) authorize the EPA in promulgating a FIP to establish ''enforceable emission limitations'' in addition to other types of control measures like mass-based trading programs. Further, in this action, the EPA has developed an emissions control strategy that prohibits the ''amount'' of pollution that significantly contributes to nonattainment and/or interferes with maintenance. We determine that amount, as we have in prior transport actions, at Step 3 of the analysis, by applying a multifactor analysis that includes considering cost and downwind air quality effects. *See* section V.A of this document. With the implementation of the selected controls (at Step 4) through both an emissions trading program for power plants and source-specific emissions limitations for industrial sources, those ''amounts'' that had been emitted prior to imposition of the controls will be eliminated.

The Act does not mandate that the EPA must set a specific mass-based budget for each state to eliminate significant contribution based on the use of the term ''amounts'' in CAA section 110(a)(2)(D)(i). As the Supreme Court recognized, the statute ''*requires* States to eliminate those 'amounts' of pollution that 'contribute significantly to nonattainment' in downwind States,'' and it delegates to states or EPA acting in their stead discretion to determine *how* to apportion responsibility among those upwind states. 572 U.S. at 514 (emphasis added). The statute does not define the term ''amount'' in the way commenters suggest (or in any other way), and neither the Agency nor any court has reached that conclusion. The

Supreme Court itself has recognized that the language of the good neighbor provision is amenable to different types of metrics for quantification of ''significant contribution.'' *See EME Homer City Generation, L.P.,* 572 U.S. at 514 (''How is EPA to divide responsibility among the . . . States? Should the Agency allocate reductions proportionally . . ., on a per capita basis, on the basis of the cost of abatement, or by some other metric? . . . The Good Neighbor Provision does not answer that question for EPA.''); *see also Michigan* v. *EPA,* 213 F.3d 663, 677 D.C. Cir. 2000) (''Nothing in the text of . . . the statute spells out a criterion for classifying 'emissions activity' as 'significant.' ''); *id.* at 677 (''Must EPA simply pick some flat 'amount' of contribution . . . ?''). When the State of Delaware petitioned the Agency under CAA section 126(b) to establish daily emissions rates for EGUs to remedy what it saw as continuing violations of the good neighbor provision for the 2008 ozone NAAQS, neither the EPA nor the reviewing court questioned whether the Agency had the statutory authority to do so. The EPA's decision not to was upheld on record grounds. *See Maryland* v. *EPA,* 958 F.3d 1185, 1207 D.C. Cir. 2020) (''In other words, Delaware's concern makes sense but has not been observed in practice.'').[80]

The term ''amounts'' can be interpreted to refer to any number of metrics, and in fact the CAA uses the term in several contexts where it is clear Congress did not intend the term to refer to a fixed, mass-based quantity of emissions. For example, in the definition of ''lowest achievable emission rate'' (LAER) in CAA section 171, the Act provides that the application of LAER shall not permit a proposed new or modified source to emit any pollutant in excess of ''the amount allowable under applicable new source standards of performance [NSPS].'' NSPS may be, and usually are, set as emissions standards or limitations that are rate- or concentration-based. *See, e.g.,* 40 CFR part 60, subpart KKKK, table I (establishing concentration-based and rate-based emissions limits for stationary combustion turbines).[81] Congress has elsewhere used the term ''amount'' in the CAA to refer to concentration-based standards. For example, in CAA section 163(b), Congress provided that maximum allowable increases in concentrations of certain pollutants ''shall not exceed the following amounts,'' with a list of allowable increases provided that are expressed in micrograms per cubic meter.[82] As a third example, in the 1990 CAA Amendments, Congress provided that ozone nonattainment areas classified as Serious must provide a reasonable further progress demonstration of reductions in VOC emissions ''equal to the following amount,'' which is then described as a percentage reduction from baseline emissions. CAA section 182(c)(2)(B). These examples illustrate that the word ''amounts'' is amenable to a variety of meanings depending on what is being measured or quantified. It would therefore be highly unlikely that Congress could have intended that ''amount'' as used in the good neighbor provision must signify only a fixed mass budget of emissions for each state expressed as total tons per ozone season.

Such an approach would, in fact, fail to address an important aspect of the problem of interstate transport. As explained in sections III.B.1.d, V.D.4, and VI.B.1, the EPA in this rule seeks to better address the need for emissions reductions on each day of the ozone season, reflecting the daily, but unpredictably recurring, nature of the air pollution problem, short-term health impacts, and the form of the 2015 ozone NAAQS, wherein nonattainment for downwind areas (and thus heightened regulatory requirements) could be based on ozone exceedances on just a few days of the year. The expression of the ''amount'' of pollution that should be eliminated to address upwind states' ''significant contribution'' to that type of air pollution problem may appropriately take into account those aspects of the problem, and the EPA may appropriately conclude, as we do here, that a single, fixed, emissions budget covering an entire ozone season is not sufficient to the task at hand.

In this action, the EPA reasonably applies the good neighbor provision, including the term ''amount,'' through the 4-step interstate transport framework. Under this approach, the EPA here, as it has in prior transport rulemakings for regional pollutants like ozone, identifies a uniform level of emissions reduction that the covered sources in the linked upwind states can achieve that cost-effectively delivers improvement in air quality at downwind receptors on a regional scale. The ''amount'' of pollution that is identified for elimination at Step 3 of the framework is therefore that amount of emissions that is in excess of the emissions control strategies the EPA has deemed cost-effective. Contrary to commenters' views, in prior transport rules utilizing emissions trading, the mass budgets through which the elimination of significant contribution was effectuated did not constitute the ''amounts'' to be eliminated but rather the residual emissions remaining following the elimination of significant contribution through the control stringency selected based on our multifactor assessment at Step 3. Nor did the EPA consider a mass-based budget to be the sole expression, even indirectly, of what constituted ''significant contribution.'' *See, e.g.,* CSAPR, 76 FR 48256–57 (discussing the evaluation of the control strategies that would eliminate significant contribution for the 1997 ozone NAAQS, including combustion controls, and explaining, ''[I]t would be inappropriate for a state linked to downwind nonattainment or maintenance areas to stop operating existing pollution control equipment (which would increase their emissions and contribution).'').

In other actions the EPA has taken to implement good neighbor obligations, the EPA has required or allowed for reliance on source-specific emissions limitations rather than defining significant contribution as a mass-based budget. For example, the EPA imposed unit-specific emissions limitations in granting a CAA section 126(b) petition from the State of New Jersey in 2011. Final Response to Petition From New Jersey Regarding SO_2 Emissions From the Portland Generating Station, 76 FR 69052, 69063–64 (Nov. 7, 2011) (discussing the analytical basis for the establishment of emissions limits at specific units). This action was upheld by the Third Circuit in *Genon Rema LLC* v. *EPA,* 722 F.3d 513, 526 (3d. Cir. 2013).[83]

[80] The Agency's view of the basis for backstop daily emissions rates for certain EGUs within the trading program has changed since the time of its action on Delaware's petition, as explained in section VI.B.

[81] The EPA has interpreted the term ''amount'' as used in CAA section 111(a)(4) in the definition of the term ''modifications'' as an increase in a rate of emissions expressed as kilograms per hour. 40 CFR 60.14(b).

[82] Notably, both the provisions of CAA section 171 and section 163 given as examples here were added by the CAA Amendments of 1977, in the same set of amendments that Congress first strengthened the good neighbor provision and added the term ''amounts.'' *See* Public Law 95–95, 91 Stat. 685, 693, 732, 746.

[83] In CAA section 126(c), Congress provided for the EPA to directly impose ''emission limitations'' to eliminate prohibited significant contribution. Notably, the statute affords the EPA and states flexibility in how an ''emissions limitation'' may be expressed, including as a ''quantity, rate, or concentration,'' *see* CAA section 302(k). It would make little sense that the EPA could only establish a mass-based definition of ''amounts'' under CAA section 110(a)(2)(D)(i)(I), when the statute provides for rate- or concentration-based limitations in CAA section 126, which directly incorporates

Even where the EPA has provided for implementation of good neighbor requirements through mass-based budgets, it has recognized that other approaches may be acceptable as providing an equivalent degree of emissions reduction to eliminate significant contribution. *See, e.g.,* NO_X SIP Call, 63 FR 57378–79 (discussing approvability of rate-based emissions limit approaches for implementing NO_X SIP Call and providing, ''the 2007 overall budget is an important accounting tool. However, the State is not required to demonstrate that it has limited its total NO_X emissions to the budget amounts. Thus, the overall budget amount is not an independently enforceable requirement.''); CAIR, 70 FR 25261–62 (discussing ways states could implement CAIR obligations, including through emission-rate limitations, so long as adequately demonstrated to achieve comparable reductions to CAIR's emissions budgets).

Finally, as it has in its prior transport FIP actions, the EPA has in this action provided guidance for states on methods by which they could replace this FIP with SIPs, and in so doing, continues to recognize substantial state flexibility in achieving an equivalent degree of emissions reduction that would successfully eliminate significant contribution for the 2015 ozone NAAQS. *See* section VI.D of this document. While the EPA has exercised the responsibility it has under CAA section 110(c)(1) to step into the shoes of the covered states and directly implement good neighbor requirements through a particular set of regulatory mechanisms in this action, we anticipate that states may identify alternative, equivalent mechanisms that we would be bound to evaluate and approve if satisfactory, should states seek to replace this FIP with a SIP.

For these reasons, the EPA disagrees with the contention that it is constrained by the good neighbor provision to define upwind state obligations solely by reference to a fixed, mass budget. We find it reasonable in this action to again determine the amount of ''significant contribution'' at Step 3 by reference to uniform levels of cost-effective emissions controls that can be applied across the upwind sources. And, we find it appropriate to implement those emissions reductions at Step 4 through mechanisms that go beyond fixed, mass-based, ozone-season long budgets.

The EPA's authority for its industrial source control strategies is further discussed in sections II.C. and III.B.1.c of this document. The relationship of the control strategy to the assessment of overcontrol is discussed in section V.D.4 of this document. The relationship of our FIP authority to state authorities and SIP calls under CAA section 110(k)(5) is further discussed in *RTC* sections 1 and 2.

a. Step 1 Approach

As proposed, the EPA applies the same basic method of the CSAPR Update and the Revised CSAPR Update for identifying nonattainment and maintenance receptors. However, we received comments arguing that the outcome of applying our methodology to identify receptors in 2023 appears overly optimistic in light of current measured data from the network of ambient air quality monitors across the country. These commenters suggest that the EPA give greater weight to current measured data as part of the method for identifying projected receptors. As discussed further in section IV.D of this document, the EPA has modified its approach for identifying receptors for this final rule in response to these comments.

This concern is more evident given that the 2023 ozone season is just a few months away, and the most recent measured ozone values in many areas strongly suggest that these areas will not likely see the substantial reduction in ozone levels that the 2016v2 and 2016v3 modeling continue to project.

It would not be reasonable to ignore recent measured ozone levels in many areas that are clearly not fully consistent with certain concentrations in the Step 1 analysis for 2023. Therefore, the EPA has developed an additional maintenance-only receptor category, which includes what we refer to as ''violating monitor'' receptors, based on current ozone concentrations measured by regulatory ambient air quality monitoring sites. We acknowledge that the traditional modeling plus monitoring methodology we used at proposal and in prior ozone transport rules would otherwise have identified such sites as being in attainment in 2023. Despite the implications of the current measured data suggesting there will be a nonattainment problem at these sites in 2023, we cannot definitively establish that such sites will be in nonattainment in 2023 in light of our modeling projections. In the face of this uncertainty, we regard our ability to consider such sites as receptors for purposes of good neighbor analysis under CAA section 110(a)(2)(D)(i)(I) to be a function of the requirement to prohibit emissions that interfere with maintenance of the NAAQS; even if our transport modeling projects that an area may reach attainment in 2023, we have other information indicating that there is an identified risk that attainment will not in fact be achieved in 2023. The EPA's analysis of these additional receptors further is explained in section IV.D of this document.

However, because we did not identify this basis for receptor-identification at proposal, in this final action we are only using this receptor category on a confirmatory basis. That is, for states that we find linked based on our traditional modeling-based methodology in 2023, we find in this final analysis that the linkage at Step 2 is strengthened and confirmed if that state is also linked to one or more ''violating monitor'' receptors. If a state is only linked to a violating-monitor receptor in this final analysis, we are deferring promulgating a final FIP (and we have also deferred taking final action on that state's SIP submittal). This is the case for the State of Tennessee. Among the states that previously had their transport SIPs fully approved for the 2015 ozone NAAQS, the EPA has also identified a linkage to violating-monitor receptors for the State of Kansas. The EPA intends to further review its air quality modeling results and recent measured ozone levels, and we intend to address these states' good neighbor obligations as expeditiously as practicable in a future action.

b. Step 2 Approach

The EPA applies the same approach for identifying which states are contributing to downwind nonattainment and maintenance receptors as it has applied in the three prior CSAPR rulemakings. CSAPR, the CSAPR Update, and the Revised CSAPR Update used a screening threshold of 1 percent of the NAAQS to identify upwind states that were ''linked'' to downwind air pollution problems. States with contributions greater than or equal to the threshold for at least one downwind nonattainment or maintenance receptor identified in Step 1 were identified in these rules as needing further evaluation of their good neighbor obligations to downwind states at Step 3.[84] The EPA evaluated each state's contribution based on the average relative downwind impact calculated

110(a)(2)(D)(i)(I). (In observing this, we do not concede that an ''emissions limitation'' itself could not also be expressed through a mass-based approach, which may be read as authorized by the term ''quantity,'' a term also used in CAA section 302(k).)

[84] For ozone, the impacts include those from VOC and NO_X from all sectors.

over multiple days.[85] States whose air quality impacts to all downwind receptors were below this threshold did not require further evaluation for measures to address transport. In other words, the EPA determined that these states did not contribute to downwind air quality problems and therefore had no emissions reduction obligations under the good neighbor provision. The EPA applies a relatively low contribution screening threshold because many downwind ozone nonattainment and maintenance receptors receive transport contributions from multiple upwind states. While the proportion of contribution from a single upwind state may be relatively small, the effect of collective contribution resulting from multiple upwind states may substantially contribute to nonattainment of or interference with maintenance of the NAAQS in downwind areas. The preambles to the proposed and final CSAPR rules discuss the use of the 1 percent threshold for CSAPR. *See* 75 FR 45237 (August 2, 2010); 76 FR 48238 (August 8, 2011). The same metric is discussed in the CSAPR Update, *see* 81 FR 74538, and in the Revised CSAPR Update, *see* 86 FR 23054. In this final rule, the EPA has updated the air quality modeling data used for determining contributions at Step 2 of the 4-step interstate transport framework using the 2016v3 modeling platform. The EPA continues to find that this threshold is appropriate to apply for the 2015 ozone NAAQS. This rule's application of the Step 2 approach is comprehensively described in section IV of this document.

Many commenters challenged the use of a 1 percent of NAAQS threshold or otherwise raised issues with the EPA's Step 2 methodology. These comments are addressed in section IV.F of this document and in the *RTC* document.

c. Step 3 Approach

The EPA continues to apply the same approach as the prior three CSAPR rulemakings for evaluating ''significant contribution'' at Step 3.[86] For states that are linked at Step 2 to downwind air quality problems, CSAPR, the CSAPR Update, and the Revised CSAPR Update evaluated NO_X reduction potential, cost, and downwind air quality improvements available at various mitigation technology breakpoints (represented by cost thresholds) in the multi-factor test. In CSAPR, the CSAPR Update, and the Revised CSAPR Update, the EPA selected the technology breakpoint (represented by a cost threshold) that, in general, maximized cost-effectiveness—*i.e.,* that achieved a reasonable balance of incremental NO_X reduction potential and corresponding downwind ozone air quality improvements, relative to the other emissions budget levels evaluated. *See, e.g.,* 81 FR 74550. The EPA determined the level of emissions reductions associated with that level of control stringency to constitute significant contribution to nonattainment or interfere with maintenance of a NAAQS downwind. *See, e.g.,* 86 FR 23116. This approach was upheld by the U.S. Supreme Court in *EPA* v. *EME Homer City*.[87]

In this action, the EPA applies this approach to identify EGU and non-EGU NO_X control stringencies necessary to address significant contribution for the 2015 ozone NAAQS. The EPA applies a multifactor assessment using cost-thresholds, total emissions reduction potential, and downwind air quality effects as key factors in determining a reasonable balance of NO_X controls in light of the downwind air quality problems. The EPA's evaluation of available NO_X mitigation strategies for EGUs focuses on the same core set of measures as prior transport rules, and the EPA finalizes a control stringency for EGUs from these measures that is commensurate with the nature of the ongoing ozone nonattainment and maintenance problems observed for the 2015 ozone NAAQS. Similarly, in this action, the EPA includes other industrial sources (non-EGUs) in its Step 3 analysis and finalizes emissions limitations for certain non-EGU sources as needed to eliminate significant contribution and interference with maintenance. The available reductions and cost-levels for the non-EGU stringency is commensurate with the control strategy for EGUs.

In CSAPR, the CSAPR Update, and the Revised CSAPR Update, the EPA focused its Step 3 analysis on EGUs. In the Revised CSAPR Update, in response to the *Wisconsin* decision's finding that the EPA had not adequately evaluated potential non-EGU reductions, *see* 938 F.3d at 318, the EPA determined that the available NO_X emissions reductions from non-EGU sources, for purposes of addressing good neighbor obligations for the 2008 ozone NAAQS, at a comparable cost threshold to the required EGU emissions reductions (for which the EPA used an adjusted representative cost of $1,800 per ton), and based on the timing of when such measures could be implemented, did not provide a sufficiently meaningful and timely air quality improvement at the downwind receptors before those receptors were projected to resolve. *See* 86 FR 23110. On that basis, the EPA made a finding that emissions reductions from non-EGU sources were not required to eliminate significant contribution to downwind air quality problems under the interstate transport provision for the 2008 ozone NAAQS. In this rule, the EPA's ''significant contribution'' analysis at Step 3 of the 4-step framework includes a comprehensive evaluation of major stationary source non-EGU industries in the linked upwind states. The EPA finds that emissions from certain non-EGU sources in the upwind states significantly contribute to downwind air quality problems for the 2015 ozone NAAQS, and that cost-effective emissions reductions from these sources are required to eliminate significant contribution under the interstate transport provision. Therefore, this rule requires emissions reductions from non-EGU sources in upwind states to fulfill interstate transport obligations for the 2015 ozone NAAQS. This analysis is described fully in section V of this document.

In this rule, the EPA also continues to apply its approach for assessing and avoiding ''over-control.'' In *EME Homer*

[85] The number of days used in calculating the average contribution metric has historically been determined in a manner that is generally consistent with the EPA's recommendations for projecting future year ozone design values. Our ozone attainment demonstration modeling guidance at the time of CSAPR recommended using all model-predicted days above the NAAQS to calculate future year design values (*https://www3.epa.gov/ttn/scram/guidance/guide/final-03-pm-rh-guidance.pdf*). In 2014, the EPA issued draft revised guidance that changed the recommended number of days to the top-10 model predicted days (*https://www3.epa.gov/ttn/scram/guidance/guide/Draft-O3-PM-RH-Modeling_Guidance-2014.pdf*). For the CSAPR Update, the EPA transitioned to calculating design values based on this draft revised approach. The revised modeling guidance was finalized in 2019 and, in this regard, the EPA is calculating both the ozone design values and the contributions based on a top-10 day approach (*https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf*).

[86] For simplicity, the EPA (and courts) at times will refer to the Step 3 analysis as determining ''significant contribution''; however, the EPA's approach at Step 3 also implements the ''interference with maintenance'' prong of the good neighbor provision by also addressing emissions that impact the maintenance receptors identified at Step 1. *See* 86 FR 23074 (''In effect, EPA's determination of what level of upwind contribution constitutes 'interference' with a maintenance receptor is the same determination as what constitutes 'significant contribution' for a nonattainment receptor. Nonetheless, this continues to give independent effect to prong 2 because the EPA applies a broader definition for identifying maintenance receptors, which accounts for the possibility of problems maintaining the NAAQS under realistic potential future conditions.''). *See also EME Homer City,* 795 F.3d 118, 136 (upholding this approach to prong 2).

[87] *EPA* v. *EME Homer City Generation, L.P.,* 572 U.S. 489 (2014).

City, the Supreme Court held that ''EPA cannot require a State to reduce its output of pollution by more than is necessary to achieve attainment in every downwind State or at odds with the one-percent threshold the Agency has set.'' 572 U.S. at 521. The Court acknowledged that ''instances of 'over-control' in particular downwind locations may be incidental to reductions necessary to ensure attainment elsewhere.'' *Id.* at 492.

> Because individual upwind States often 'contribute significantly' to nonattainment in multiple downwind locations, the emissions reductions required to bring one linked downwind State into attainment may well be large enough to push other linked downwind States over the attainment line. As the Good Neighbor Provision seeks attainment in *every* downwind State, however, exceeding attainment in one State cannot rank as 'over-control' unless unnecessary to achieving attainment in *any* downwind State. Only reductions unnecessary to downwind attainment *anywhere* fall outside the Agency's statutory authority.

Id. at 522 (footnotes omitted).

The Court further explained that ''while EPA has a statutory duty to avoid over-control, the Agency also has a statutory obligation to avoid 'under-control,' *i.e.,* to maximize achievement of attainment downwind.'' *Id.* at 523. Therefore, in the CSAPR Update and Revised CSAPR Update, the EPA evaluated possible over-control by considering whether an upwind state is linked solely to downwind air quality problems that can be resolved at a lower cost threshold, or if upwind states would reduce their emissions at a lower cost threshold to the extent that they would no longer meet or exceed the 1 percent air quality contribution threshold. *See, e.g.,* 81 FR 74551–52. *See also Wisconsin,* 938 F.3d at 325 (over-control must be proven through a '' 'particularized, as-applied challenge' '') (quoting *EME Homer City Generation,* 572 U.S. at 523–24). The EPA continues to apply this framework for assessing over-control in this rule, and, as discussed in section V.D.4 of this document, does not find any over-control at the final control stringency selected.

This evaluation of cost, NO_X reductions, and air quality improvements, including consideration of whether there is proven over-control, results in the EPA's determination of the appropriate level of upwind control stringency that would result in elimination of emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind areas.

Comment: Commenters alleged that the EPA lacks authority to regulate EGUs under the good neighbor provision of the CAA, or at least in the manner proposed, because in their view, this regulation would intrude into areas of regulation that are reserved to other Federal agencies or are beyond the EPA's expertise. They focused in particular on the EGU trading program enhancements, which they alleged would threaten electric grid reliability, and asserted that EPA lacks authority or expertise to dictate the mix of electricity generation in the country.

Response: The EPA disagrees that the regulation of EGUs in this action is unlawful or unsupported. The Agency has consistently and successfully regulated EGUs' ozone season NO_X emissions under the good neighbor provision for over 25 years, beginning with the 1997 NO_X SIP Call. This action does not intrude on other Federal agencies' authorities and responsibilities with respect to managing the electric power grid and ensuring reliable electricity. While other agencies such as the Federal Energy Regulatory Commission (FERC) have primary responsibility for ensuring reliability of the bulk electric system, the EPA has ensured that its final rule here will not create electric reliability concerns. See section VI.B.1.d of this document. Thus, to the extent commenters are raising a record-based issue that the EPA through this action has created a reliability concern, we disagree. The EPA engaged in a series of stakeholder meetings with Reliability Coordinators who commented on the proposed rule, including several Regional Transmission Organizations (RTOs) as well as non-RTO entities throughout the rulemaking process.[88]

To the extent commenters maintain that—despite this record of collaboration and sensitivity to the need to ensure reliability in the implementation of its mandates, including in this rule—the EPA nonetheless fundamentally lacks authority to regulate the electric-power sector in any way that ''impact[s] national electricity and energy markets,'' the EPA disagrees. The EPA has successfully regulated interstate ozone-precursor emissions from the power sector since the NO_X SIP Call and the establishment of the NO_X Budget Trading Program. *See generally Michigan* v. *EPA,* 213 F.3d 663 (D.C. Cir. 2000); *Appalachian Power Co.* v. *EPA,* 249 F.3d 1032 (D.C. Cir. 2001). In fact, each of the EPA's interstate ozone transport rulemakings has focused on the regulation of ozone-precursor emissions from the power sector (all but the NO_X SIP Call exclusively), because substantial, cost-effective reductions in ozone-precursor emissions have been and continue to be available from fossil-fuel fired EGUs. *See, e.g.,* 63 FR 57399–400 (NO_X SIP Call); 70 FR 25165 and 71 FR 25343 (CAIR and CAIR FIP); 76 FR 48210–11 (CSAPR); 81 FR 74507 (CSAPR Update); 86 FR 23061 (Revised CSAPR Update).[89]

This rule, like all prior EPA ozone-transport rulemakings, regulates only one aspect of the operation of fossil-fuel fired EGUs, that is, the emissions of NO_X as an ozone-precursor pollutant during the ozone season. This rule limits EGU NO_X emissions that interfere with downwind states' ability to attain and maintain the 2015 ozone NAAQS. The rule does not regulate any other aspect of energy generation, distribution, or sale. For these reasons, the rule does not intrude on FERC's power under the Federal Power Act, 16 U.S.C. 791a, *et seq.* And, as in prior transport rules, the EPA implements this regulation through a proven, flexible mass-based emissions trading program that integrates well with, and in no way intrudes upon, the management of the power sector under other state and Federal authorities. This rule will not alter the procedures system operators employ to dispatch resources or force changes to FERC-jurisdictional electricity markets, nor have commenters offered any explanation in this regard themselves.

The actual compliance requirement that the EGUs must meet in the allowance trading system finalized here—just as in all prior interstate transport trading programs—is simply to hold sufficient allowances to cover emissions during a given control period, not to undertake any specific

[88] See Documents no. EPA–HQ–OAR–2021–0668–0938, EPA–HQ–OAR–2021–0668–0940, EPA–HQ–OAR–2021–0668–0941, EPA–HQ–OAR–2021–0668–0942, EPA–HQ–OAR–2021–0668–0943, EPA–HQ–OAR–2021–0668–0944, and EPA–HQ–OAR–2021–0668–0945 in the docket for this rulemaking.

[89] There are myriad other examples of effective power sector regulation under the CAA and other environmental statutes, including for example, new source performance standards (NSPS), best available retrofit technology (BART) requirements, and mercury and air toxics standards (MATS) under the CAA; effluent limitation guidelines (ELGs) under the Clean Water Act; and coal combustion residuals (CCR) requirements under the Resource Conservation and Recovery Act. Whether implemented through unit- or facility-level pollution control requirements or through emissions-trading or other market-based programs, these regulations have been effective in reducing air and water pollution while not intruding into the regulatory arenas of other state and Federal entities. *See* Section 1 of the *RTC* for further discussion.

compliance strategy.[90] The owner or operator of an EGU has flexibility in determining how it will meet this requirement, whether through the add-on emissions controls that the EPA has selected in our Step 3 analysis, or through some other method or methods of compliance. The costs of meeting this allowance-holding requirement—just like the cost associated with meeting any other regulatory requirements—could possibly then be factored into what that unit bids in the wholesale electricity market (or in regulated jurisdictions, would factor into utility regulators' determinations of what can be cost-recovered).

Those costs could, in turn, result in a reduction in electricity generation from higher-emitting sources and an increase in electricity generation from lower-emitting or zero-emitting generators, but that kind of generation shifting (not mandated but occurring as an economic choice by the regulated sources) is consistent, and in no way interferes with, the existing security-constrained economic dispatch protocols of the modern electrical grid. Further, this type of ''impact'' on electricity markets—merely incidental, not mandated or even intended—is of the same type that results from any other kind of regulation, environmental or otherwise. Indeed, the U.S. Supreme Court recognizes that regulatory actions that may have some ''effect,'' or impact, in electricity markets do not on that basis alone intrude into authorities reserved to electricity rate-setting regulators by the Federal Power Act. *See FERC* v. *Electric Power Supply Ass'n,* 577 U.S. 260, 282–84 (2016) (distinguishing between actions that have an effect on retail rates and actual intrusion into retail rate-setting itself); *see also Hughes* v. *Talen,* 578 U.S. 150, 166 (2016). The Supreme Court again recognized this distinction between ''incidental'' effects caused by lawfully issued environmental regulations and attempts to mandate a particular energy mix in *West Virginia* v. *EPA. See* 142 S. Ct. 2587, 2613 n.4 (2022) (''[T]here is an obvious difference between (1) issuing a rule that may end up causing an incidental loss of coal's market share, and (2) simply announcing what the market share of coal, natural gas, wind, and solar must be . . . .'').

This rule is squarely in the former camp; as the most stringent component of its emissions controls strategy for EGUs, the EPA has determined that to eliminate significant contribution to harmful levels of ozone in other states, certain fossil-fuel fired EGUs in ''linked'' upwind states that do not already have selective catalytic reduction (SCR) post-combustion control technology, should install it (or achieve emissions reductions commensurate with that technology). SCR is a well-established at-the-source NO_X control technology already in use by EGUs representing roughly 60 percent of the existing coal-fired generating capacity in the United States. This technology can be installed and operated to reduce NO_X emissions without forcing the retirement or reduced utilization of any EGU. However, if market conditions are such that an EGU faced with this mandate (again, as expressed through an emissions trading budget) finds it more economic to comply with the mandate through the purchase of allowances, installation of other types of pollution control, reduced utilization, and/or retirement, rather than installing SCR technology, that is a choice that the EGU owner/operator can freely make under this rule.[91] Security constrained economic dispatch is thereby maintained and is in no way interfered with.

The EPA recognizes that cost to operate generators is one of the major factors that system operators utilize to determine ''merit'' order in dispatching resources. However, this rule does not intrude in any way into that process. To the extent that compliance with environmental regulations is a kind of cost that may need to be factored into generators' bids, this rule is no different than many other such requirements EGUs are already subject to. Further, as in prior transport rules, this rule applies a uniform control stringency to EGUs within the covered upwind states. EGUs that may have enjoyed a competitive advantage in the past through not bearing the costs of installing and running state-of-the-art emissions control technology now must bear that cost just as their competitors with that technology already are. *Cf. EME Homer City,* 572 U.S. 489, 519 (CSAPR is ''[e]quitable because, by imposing uniform cost thresholds on regulated States, EPA's rule subjects to stricter regulation those States that have done relatively less in the past to control their pollution. Upwind States that have not yet implemented pollution controls of the same stringency as their neighbors will be stopped from free riding on their neighbors' efforts to reduce pollution. They will have to bring down their emissions by installing devices of the kind in which neighboring States have already invested.'').

Finally, we note that this final rule does not include ''generation shifting'' as a component of the budget-setting process, even in the limited way that it had been used in prior transport rules like CSAPR and the CSAPR Update, *i.e.,* to ensure the budget provided adequate incentive to ensure implementation of the selected emission-control strategy. *See* section V.B.1.f of this document. Further comments regarding legal authority for ''generation shifting,'' relationship to state authorities, and expertise associated with grid reliability are addressed in section 1.3 of the *RTC.* We further discuss our consideration of grid reliability concerns and adjustments in the approach to the EGU emissions trading program from proposal in section VI.B.1.d of this document.

Comment: Commenters generally challenged the EPA's authority to establish emissions control requirements for non-EGU industrial sources in this action, or argued that such controls are unnecessary or unsupported, or run contrary to the EPA's prior actions under the good neighbor provision.

Response: The states and the EPA have authority under CAA section 110(a)(2)(D)(i)(I) to prohibit emissions from ''any source or other type of emissions activity'' that are found to significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind states. This language is not limited only to power plant emissions, nor is it limited only to ''major'' sources or ''stationary'' sources. Thus, as a legal

[90] The EPA has included in this trading program certain ''enhancements'' to ensure that the program continues to eliminate the emissions the EPA has determined constitute ''significant contribution'' over the entire life of the trading program. While one of the enhancements elevates a type of conduct that was already strongly discouraged into an enforceable violation, the other enhancements all simply modify the traditional allowance-based program structure to revise how the specific quantities of allowances that must be surrendered or the specific quantities of allowances available for surrender are determined. In finalizing this rule, the EPA has made a number of changes to its proposed enhancements to the trading program in response to comment and in part to ensure no impact on system reliability. Nonetheless, with these changes, the EPA has determined that the enhanced trading program can be implemented without impacting grid reliability. See section VI.B.1.d of this document.

[91] As explained in section V.B of this document, the imposition of a backstop emissions rate beginning in 2030 for units that do not already have SCR installed could lead the owner of a given unit to decide that the unit's continued operation would be uneconomic without installation of SCR, but the establishment of technology-based emissions rates that require such decisions is consistent with decades of the EPA's rulemaking and permitting actions requiring source-specific pollution controls. Further, the backstop rate in this program is implemented through an enhanced allowance-surrender ratio, thus preserving some degree of flexibility through the emissions-trading program as the mechanism of compliance.

matter, the emissions control requirements for certain large ''non-EGU'' industrial sources in this action are grounded in unambiguous statutory authority, in particular the statute's use of the broad term ''any source.'' Whereas the Act elsewhere includes definitions of ''major stationary source,'' ''small source,'' and ''stationary source,'' *see, e.g.,* CAA section 302(j), (x), and (z), no such qualifying terms are used with respect to the term ''any source'' at CAA section 110(a)(2)(D)(i). Rather, the scope of authority in this provision expands to encompass ''other type of emissions activity'' in addition to ''any source.'' The EPA has previously included non-EGU industrial sources in findings quantifying states' obligations under the good neighbor provision, in the 1998 NO_X SIP Call, *see* 63 FR 57365.[92] *See also Michigan* v. *EPA,* 213 F.3d 663, 690–93 (upholding the inclusion of certain non-EGU boilers in the NO_X SIP Call). The EPA's determinations in prior transport rules not to regulate sources beyond the power sector were grounded in considerations not related to the Agency's statutory authority. For example, in the original CSAPR rulemaking, the EPA determined that the analytical effort needed to regulate non-EGU industrial sources would substantially delay the implementation of emissions reductions from the power sector. *See, e.g.,* 76 FR 48247–48 (''[D]eveloping the additional information needed to consider NO_X emissions from non-EGU source categories to fully quantify upwind state responsibility with respect to the 1997 ozone NAAQS would substantially delay promulgation of the Transport Rule. . . . [W]e do not believe that effort should delay the emissions reductions and large health benefits this final rule will deliver[.]''). The EPA acknowledged that by not addressing non-EGUs, it may not have promulgated a complete remedy to good neighbor obligations in CSAPR, *id.* at 48248. Nonetheless, the EPA went on to explain that there were limited emissions reductions available from non-EGUs at the cost thresholds the EPA determined would deliver substantial reductions from power plants. *See id.* at 48249 (the EPA's ''preliminary assessment in the rule proposal suggested that there likely would be very large emissions reductions available from EGUs before costs reach the point for which non-EGU sources have available reductions . . . . EPA revisited these non-EGU reduction cost levels in this final rulemaking and verified that there are little or no reductions available from non-EGUs at costs lower than the thresholds that EPA has chosen . . . .''). The EPA noted in CSAPR that states retained the authority to regulate non-EGUs as a method of addressing their good neighbor obligations. *Id.* at 48320. The EPA also noted in CSAPR that ''potentially substantial'' non-EGU emissions reductions could be available in future rulemakings applying a higher cost threshold. *See id.* at 48256.

Similarly, in the CSAPR Update, which addressed good neighbor obligations for the 2008 ozone NAAQS, the EPA found that regulation of non-EGUs was not warranted as the analysis required could delay the expeditious implementation of power plant reductions. The EPA found that the availability and cost-effectiveness of non-EGU reductions was uncertain and further analysis could delay implementation of the EGU strategy beyond 2017. The EPA acknowledged that it was not promulgating a complete remedy for good neighbor obligations for the 2008 ozone NAAQS and indicated its intention to further review emissions-reduction opportunities from non-EGU and EGU sources. 81 FR 74521–22.

In *Wisconsin,* the court held that the EPA's deferral of a complete good neighbor remedy by 2017, on the basis, among other things, of uncertainty regarding non-EGU emissions reductions and the need for further regulatory analysis, was unlawful. 938 F.3d at 318–19. The court noted that '' 'the statutes and common sense demand regulatory action to prevent harm, even if the regulator is less than certain.' '' *Id.* at 319 (quoting *Ethyl Corp.* v. *EPA,* 541 F.2d 1, 24–25 (D.C. Cir. 1976)), and that agencies can only avoid meeting their statutory obligations where ''scientific uncertainty is so profound that it precludes EPA from making a reasoned judgment.'' *Id.* (citing *Massachusetts* v. *EPA,* 549 U.S. 497, 534 (2007)). Further, the court rejected the EPA's argument that it would have delayed its rulemaking if the EPA needed to complete a non-EGU analysis in a timely manner, holding that ''administrative infeasibility'' is not sufficient to ''justify . . . noncompliance with the statute.'' *Id.* Rather, the Agency would need to ''meet the 'heavy burden to demonstrate the existence of an impossibility.' '' *Id.* (quoting *Sierra Club* v. *EPA,* 719 F.2d 436, 462 (D.C. Cir. 1983)).

Following the remand of the CSAPR Update in *Wisconsin,* in the Revised CSAPR Update, the EPA conducted an analysis of non-EGUs to ensure it had implemented a complete remedy to eliminate significant contribution for the covered states for the 2008 ozone NAAQS. While acknowledging uncertainty in the datasets for non-EGUs, the EPA concluded: ''[U]sing the best information currently available to the Agency, . . . the EPA is concluding that there are relatively fewer emissions reductions available at a cost threshold comparable to the cost threshold selected for EGUs. In the EPA's reasoned judgment, the Agency concludes such reductions are estimated to have a much smaller effect on any downwind receptor in the year by which the EPA finds such controls could be installed.'' 86 FR 23059. Therefore, the EPA determined control of non-EGU emissions was not required to eliminate significant contribution for the 2008 ozone NAAQS.

The circumstances that led the EPA to defer or decline regulation of non-EGU sources in CSAPR, the CSAPR Update, and the Revised CSAPR Update, are not present here, and the EPA's determination in this action that prohibiting certain emissions from certain non-EGU sources is necessary to eliminate significant contribution for the 2015 ozone NAAQS is a logical extension of the analyses and evolution of regulatory policy development spanning its prior good neighbor rules, now applied to implement this more protective NAAQS. As the EPA explained at proposal, unlike in CSAPR and the Revised CSAPR Update, in this action the EPA finds that available reductions and cost-levels for the non-EGU stringency are commensurate with the control strategy for EGUs. Following consideration of comments and after some adjustments in the non-EGU analysis and control strategy, in this final rule, the EPA continues to find this to be the case. *See* sections V.C and V.D of this document.

In particular, the EPA continues to find that cost-effective emissions reductions are available for non-EGUs at a representative cost-threshold that is lower than the cost-threshold the EPA is applying for EGUs. *See* section V.C. of this document. These emissions control strategies are generally comparable to the emissions reduction requirements that similar sources in downwind states

[92] Specifically, in the NO_X SIP Call, the EPA set statewide budgets while states could determine which sectors to regulate. The EPA recommended that states regulate certain types of non-EGUs and quantified the statewide budgets based in part on the emissions reductions from those types of non-EGUs. In the parallel rule that followed under the EPA's CAA section 126(b) authority to directly regulate emissions to eliminate significant contribution, we promulgated an emissions trading program that would have included these same types of non-EGUs. Before this rule was implemented, all states adopted equivalent state trading programs using the NO_X SIP Call model rule.

are already required to meet. *See* section V.B.2 of this document. The EPA finds that the implementation of these emissions control strategies at non-EGUs, in conjunction with the strategies for EGU, will make a cost-effective and meaningful improvement in air quality through reducing ozone levels at the identified downwind receptors, and, therefore, the EPA has determined that these strategies will eliminate the amount of upwind emissions needed to address significant contribution under the good neighbor provision. The EPA's action here is focused on the most impactful industries and emissions units as determined by our evaluation of the power sector and the non-EGU screening assessment prepared for the proposal; indeed, of the 41 industries, as identified by North American Industry Classification System codes, we analyzed, only nine industries met the criteria for further evaluation of significant contribution. *See* section V.B.2 of this document. Further, the EPA finds that these strategies do not result in ''overcontrol.'' *See* section V.D.4 of this document. As such, the EPA maintains that its final determinations regarding non-EGUs and its inclusion of non-EGU emissions sources within this final rule are statutorily authorized and lawful.[93]

The EPA disagrees that it should defer regulation of industrial sources to the NSPS program under CAA section 111(b). CAA section 111(b) does not expressly provide for the elimination of ''significant contribution'' as is required under CAA section 110(a)(2)(D)(i)(I). In particular, commenter's statement that NSPS rulemakings under section 111(b) will appropriately address the emissions that we find must be eliminated in this action is not correct. Standards under section 111(b) apply only to new and modified sources, not existing sources. This action, however, finds that reductions in ongoing emissions from existing sources are needed to eliminate significant contribution. An NSPS standard for new and modified sources would not address such emissions from existing sources. To the extent that covered sources in this action also may be covered by an older NSPS, these sources nonetheless continue to have emissions that the EPA finds significantly contribute and can be eliminated through further emissions control as determined in this action. We further disagree with commenter's separate suggestion that the EPA use section 111(b) and (d) to regulate both new and existing sources of ozone season NO_X, which is premised on the incorrect notion that the EPA's action here is an attempt to regulate entire source categories nationwide, rather than to eliminate significant contribution pursuant to CAA section 110(a)(2)(D)(i)(I). This action applies only to the extent a state is ''linked'' to downwind receptors, and therefore this action only regulates covered non-EGU industrial sources in 20 states. Further, this comment ignores that the regulation of criteria pollutant emissions from existing sources under CAA section 111(d) is limited by the criteria pollutant exclusion in CAA section 111(d)(1)(A)(i).

[93] Certain changes in the emissions control strategies for non-EGUs reflecting comments and updated information are explained in section VI.C of this document.

The EPA agrees with the commenters who assert that the EPA's authority to regulate non-EGUs under the good neighbor provision is well-grounded in administrative precedent and case law. Our previous discussion briefly recites several of the most salient aspects of that history. We also agree that the statutory language is not limited only to those sources that emit above 100 tons per year. The EPA's Step 3 and Step 4 analyses in this regard, which establish certain thresholds based on historical actual emissions, potential to emit and/or metrics for unit design capacity, reflect a reasoned judgment by the Agency regarding which emissions can be cost-effectively eliminated to address significant contribution, under the facts and circumstances of this action. That these thresholds are designed to exclude certain smaller or lower-emitting units does not reflect a determination that the EPA lacks legal authority to regulate such sources under different facts and circumstances.

The EPA identified two industry tiers of potential non-EGU emissions reductions in its non-EGU screening assessment at proposal, based on screening metrics intended to capture different kinds of impacts that non-EGU sources may have on identified receptors. The EPA agrees that it is only authorized to prohibit emissions under the good neighbor provision that significantly contribute to nonattainment or interfere with maintenance in downwind states, and we determined that these industries did so. The EPA sought comment on whether additional non-EGU industries significantly contributed to nonattainment or interfered with maintenance in downwind states. The EPA did not receive comments identifying other industrial stationary sources that are more impactful that should be regulated instead of those the EPA identified. We believed at proposal and confirm here in our final rule that the methodology used in the screening assessment comported with the factors that we consider at Step 3. Further, the EPA's 4-step interstate transport framework, including the Step 3 analysis and an overcontrol assessment, ensure that the emissions reductions achieved at each source covered by this rule are in fact justified as part of an overall, complete remedy to eliminate significant contribution for the covered states for the 2015 ozone NAAQS. The EPA has decided to finalize emissions limitations for all of the non-EGU industries, with some modifications from proposal reflecting public input, as discussed in section VI.C of this document. The Agency's authority to establish unit- and/or source-specific emissions limitations in exercising our FIP authority is further discussed in section III.B.1 of this document.

Comment: Commenters raise additional issues with the overall approach of the rule at Step 3 to address significant contribution through our evaluation of EGU and non-EGU strategies through parallel but separate analyses. They stated that the EPA failed to establish that the identified non-EGU emissions reductions are needed to eliminate significant contribution. Commenters stated that the identified non-EGU emissions reductions are not impactful of air quality at receptors or that they are much less cost-effective than the EGU emissions reductions. Commenters stated that the EPA grouped all non-EGU emissions reductions together in making a cost-effectiveness determination that is only an average and ignores significant variation in costs associated with controls on different types of non-EGU emissions units. They also stated the EPA did not assess multiple control technologies in the way that it did for EGUs, and they argued there is great variation in the profile of non-EGU industries and emissions unit types in the different upwind states or that individual emissions units do not contribute to an out-of-state air quality problem at all. Commenters argued that certain non-EGU controls were not feasible, or that the EPA had applied a different standard for ''feasibility'' for non-EGUs than it did for EGUs. Commenters stated that the EPA should have provided a mass-based trading option for non-EGUs just as it had for EGUs. By contrast, other commenters supported the regulation of non-EGUs in this action as necessary to ensure a complete remedy to good neighbor obligations, since the statute is not limited to regulating power plants.

Some commenters further stated that EGUs should not face any further emissions reduction obligation because all cost-effective controls have already been identified through prior transport rules, and that any further regulation of EGUs would only lead to the retirement of coal plants, which they believe is the EPA's true objective. Finally, some commenters argued that the EPA had not ensured that it only regulated up to the minimum needed for downwind areas to come into attainment.

Response: Issues related to the specific technical bases for the Agency's determinations of what emissions constitute ''significant contribution'' at Step 3 of the 4-step framework are addressed in section V of this document. Here, we evaluate commenters' more general assertions that this action addresses non-EGU or EGU emissions in an inconsistent way. First, the EPA agrees with commenters that the task of evaluating significant contribution from the non-EGU industries is complex compared to EGUs in light of the much greater diversity in industries and emissions unit types. This, however, is not a valid basis to avoid emissions control requirements on such sources if needed to eliminate significant contribution. In this respect, the EPA's analysis in this final rule is that the 4-step framework, as upheld by the Supreme Court in *EME Homer City,* can be adequately applied even to this more complex set of sources in a way that parallels the analysis previously conducted only for EGUs. This analysis relies on evaluation of uniform levels of control stringency across all upwind states to find a level of emissions control that is cost-effective and collectively delivers meaningful downwind air quality improvement. For non-EGUs, the EPA identified the most impactful industries and emissions unit types and evaluated emissions control strategies for these units that have been demonstrated or applied across many similar facilities and emissions units. The EPA has evaluated whether these strategies are cost-effective on a cost-per-ton basis, and in particular has compared these strategies to those selected for EGUs. This analysis is set forth in sections V and VI of this document and associated technical support documents.

Commenter's statement that the establishment of a uniform level of control for each group of industrial units across the linked upwind states fails to assess with greater precision or define a state-specific proportion of emissions reduction that is needed for each downwind receptor is effectively an attempt to relitigate *EME Homer City.* The Court in that case rejected that the EPA must define significant contribution by reference to a specific quantum of reductions that each state must achieve that is proportional to its impact at a downwind receptor. The Court agreed with the EPA's concerns as to why that approach would be problematically complicated or even impossible to apply in light of the complex set of linkages among states for a regional pollutant like ozone. *See* 572 U.S. at 515–17. The Court found that the use of uniform cost thresholds to allocate responsibility for good neighbor obligations to be efficient and equitable, in that it requires those sources that have done less to reduce their emissions to come up to a minimum level of performance to what other sources are already achieving. *Id.* at 519. The EPA's analysis in this action in section V of this document establishes that this continues to be an appropriate means of delivering meaningful air quality improvement to downwind receptors, taking into consideration the complexities of interstate pollution transport.

Not every upwind state has the same mix of non-EGU industries and emissions unit types, and it is also the case that the costs for installation of the selected level of control technology will vary from facility to facility based on site-specific considerations. This is also true for the set of EGU sources regulated here and in previous CSAPR rulemakings. These real-world complexities do not obviate the broader policy and technical judgements that the EPA makes at Step 3 regarding what level of emissions control performance can be achieved on a region-wide basis to resolve significant contribution for a regional-scale pollutant like ozone. The EPA's design of cost thresholds derives from the identification of discrete types of NO_X emissions control strategies. The EPA then identifies a representative cost-effectiveness on a per ton basis for that technology. In the Step 3 analysis, it is not the cost per ton value itself that is inherently meaningful, but rather how that cost-effectiveness value relates to other control stringencies, how many emissions reductions may be obtained, and how air quality is ultimately impacted. The selected level of control stringency reflects a point at which further emissions mitigation strategies become excessively costly on a per-ton basis while also delivering far fewer additional emissions reductions and air quality benefits. This is often referred to as a ''knee in the curve'' analysis. There are always inherent uncertainties in identifying a representative cost per ton value for any particular control stringency, but this in itself does not upset the EPA's ability to render an overall policy judgment based on the Step 3 factors as to a set of emissions control strategies that together eliminate significant contribution. *See* 86 FR 23054, 23073 (responding to similar comments on the Revised CSAPR Update).

We note that the EPA has made a number of adjustments to the non-EGU emissions limits identified at Step 4 to accommodate legitimate concerns regarding the ability of certain non-EGU facilities to meet the emissions control requirements that the EPA had proposed. The Agency's determinations regarding feasibility and installation timing for pollution controls are comparable and not inconsistent between EGUs and non-EGUs. The EPA is not establishing a trading program for non-EGUs because the Agency does not have adequate baseline emissions data and information on monitoring currently at many of these emissions units to develop emissions budgets that could reliably implement the Step 3 determinations made in this action. However, for most of the non-EGU industries,[94] the EPA is not mandating a specific control technology and is instead establishing numeric emissions limits that are uniform across the region and that allow sources to choose how to comply. The EPA's analysis, including review of RACT determinations, consent decrees, and permitting actions, shows that these emissions limits and control requirements are achievable by existing units in the non-EGU industries covered by this final rule. This rule will therefore bring all of these impactful industries and unit types across the region of linked upwind states up to this standard of performance, and thus will result collectively in a relatively substantial decrease in ozone-season NO_X emissions, with associated reductions in ozone levels projected to result at the downwind receptors. This is further discussed in section V.D.

Some commenters alleged that the EPA's EGU control strategy goes beyond the cost-effectiveness determinations of prior transport rules, and they believe that the EPA's true objective is to force the retirement of coal plants. First, we note that the EGU emissions control strategy is premised entirely on at-the-

[94] For reheat furnaces in the Iron and Steel Mills and Ferroalloy Manufacturing industry, the EPA is establishing requirements to operate low-NO_X burners achieving a specified level of emissions reduction; this approach is needed to allow for unit-specific testing before an appropriate emissions limitation can be set. *See* section VI.C.3 of this document.

source emissions control technologies that are widely available and in use across the EGU fleet. It is not the EPA's intention in this rule to force the retirement of any EGU or non-EGU facilities or emissions units but to identify and eliminate significant contribution under CAA section 110(a)(2)(D)(i)(I) based on cost-effective and proven control technologies that are appropriate in relation to address the problem of interstate transport for the 2015 ozone NAAQS. Further, determinations of cost-effectiveness must be made in relation to the particular statutory provision and its purpose. The EPA recognized in CSAPR, for example, that additional emissions reductions beyond what were determined to be cost-effective in that action could be required to implement good neighbor obligations if a NAAQS were revised to a more protective level. *See* 76 FR 48210. Here it is not surprising that a more stringent level of control could be found justified in implementing transport obligations for the more protective 2015 ozone NAAQS. Those reductions are projected to deliver meaningful air quality improvement to downwind receptors, as discussed in section V.D of this document. Those air quality benefits continue to compare favorably to the air quality benefits that will be delivered through the combined non-EGU emissions limits, which apply to nine non-EGU industries (see section V.C of this document). We find that the implementation of both the EGU and non-EGU strategies identified in section V of this document together represent the appropriate level of emissions control stringency to eliminate significant contribution under CAA section 110(a)(2)(D)(i)(I).

Finally, the EPA also analyzed for overcontrol and does not identify any. Some commenters misstate the purpose of this rule as bringing downwind receptors into attainment. In line with the statutory directive in CAA section 110(a)(2)(D)(i)(I), this rule eliminates ''significant contribution'' from upwind states; while the rule has substantial air quality benefits for downwind receptors, in many cases we project that a nonattainment or maintenance problem will continue to persist through 2023 and 2026 despite the emissions reductions achieved by this rule. Commenters alleging overcontrol have not met the requirement that overcontrol be established by particularized evidence through as-applied challenges. The Supreme Court has recognized that the EPA also has an obligation to avoid under-control and must have some leeway in fulfilling the good neighbor mandate of the Act given uncertainty in making forward projections of air quality and the efficacy or impact of emissions control determinations. *See EME Homer City,* 572 U.S. at 523. This is further addressed in section V.D.4 of this document.

d. Step 4 Approach

The EPA is finalizing an approach similar to its prior transport rulemakings to implement the necessary emissions reductions through permanent and enforceable measures. The EPA is requiring EGU sources to participate in an emissions trading program and is making additional enhancements to the trading regime to maintain the selected control stringency over time and improve emissions performance at individual units, offering a necessary measure of assurance that emissions controls will be operated throughout the ozone season. For non-EGUs, the EPA is finalizing permanent and enforceable emissions rate limits and work practice standards, and associated compliance requirements, for several types of NO_X-emitting combustion units across several industrial sectors. The measures for both EGUs and non-EGUs are required throughout the May 1-September 30 ozone season of each year. The EGU program will begin with the 2023 ozone season, and the non-EGU implementation schedule is targeted to the 2026 ozone season. Refer to section VI.A of this document for details on the implementation schedule.

Based on the EPA's experience in implementing prior transport rulemakings, the Agency is making several enhancements to its trading-program approach for implementing good neighbor requirements for EGUs. In CSAPR, the CSAPR Update, and the Revised CSAPR Update, the EPA established interstate trading programs for EGUs to implement the necessary emissions reductions. In each of these rules, EGUs in each covered state are assigned an emissions budget in each control period for their collective emissions. Emissions allowances are allocated to units covered by the trading program, and the covered units then surrender allowances after the close of the control period, usually in an amount equal to their ozone season EGU NO_X emissions. While these programs have been effective in achieving overall reductions in emissions, experience has shown that these programs may not fully reflect in perpetuity the degree of emissions stringency determined necessary to eliminate significant contribution in Step 3 and may not adequately ensure the control of emissions throughout all days of the ozone season. At the same time, the EPA continues to find that an interstate-trading program approach delivers substantial benefits at Step 4 in terms of affording an appropriate degree of compliance flexibility, certainty in emissions outcomes, data and performance transparency, and cost-effective achievement of a high degree of aggregate emissions reductions. As such, the EPA is retaining an interstate trading program approach while making several enhancements to that approach.

Thus, in this rulemaking, the EPA is including dynamic budget-setting procedures in the regulations that will allow state emissions budgets for control periods in 2026 and later years to reflect more current data on the composition and utilization of the EGU fleet (*e.g.,* the 2026 budgets will reflect recent data through 2024 data, the 2027 budgets will reflect data through 2025, etc.). These enhancements will enable the trading program to better maintain over time the selected control stringency that was determined to be necessary to address states' good neighbor obligations with respect to the 2015 ozone NAAQS. In prior programs, where state emissions budgets were static across years rather than calibrated to yearly fleet changes, the EPA has observed instances of units idling their emissions controls in the latter years of the program. To provide greater certainty regarding the minimum quantities of allowances that will be available for compliance for the control periods in 2026 through 2029, the EPA is also establishing preset state emissions budgets for these control periods, and a dynamic state emissions budget determined for one of these control periods will apply only if it is higher than the state's preset budget for the control period.

In the trading programs established for ozone season NO_X emissions under CSAPR, the CSAPR Update, and the Revised CSAPR Update, the EPA included assurance provisions to limit state emissions to levels below 121 percent of the state's budget by requiring additional allowance surrenders in the instance that emissions in the state exceed this level. This limit on the degree to which a state's emissions can exceed its budget is designed to allow for a certain level of year-to-year variability in power sector emissions to account for fluctuations in demand and EGU operations and is responsive to previous court decisions (see discussion in section VI.B.5 of this document). In this action, the EPA is maintaining the existing assurance provisions that limit state emissions to levels below a percentage of the state's budget by requiring additional allowance surrenders in any instance where emissions in the state exceed the specified level, but with adjustments that allow the level to exceed 121 percent of a state's budget in a given control period if necessary to account for actual operational conditions in that control period. In addition, the EPA is also making several additional enhancements to the EGU trading program in this action, including routine recalibrations of the total amount of banked allowances, unit-specific backstop daily emissions rates for certain units, and unit-specific secondary emissions limitations for certain units that contribute to exceedances of the assurance levels, to ensure EGU emissions control operation and associated air quality improvements. Implementation of the EGU emissions reductions using a CSAPR NO_X trading program is further described in section VI.B of this document.

In this rule, the EPA is also establishing emissions limitations for the non-EGU industry sources listed in Table II.A–1. The EPA has the authority to require emissions limitations from stationary sources, as well as from other sources and emissions activities, under CAA section 110(a)(2)(D)(i)(I). The EPA finds that requiring NO_X emissions reductions through emissions rate limits and control technology requirements for certain non-EGU industrial sources that the EPA found at Step 3 to be relatively impactful [95] on downwind air quality is an effective strategy for reducing regional ozone transport. Therefore, the EPA is establishing NO_X emissions limitations and associated compliance requirements for non-EGU sources to ensure the elimination of significant contribution of ozone precursor emissions required under the interstate transport provision for the 2015 ozone NAAQS.

Finally, the EPA finds that the control measures determined to be required for the identified EGU and non-EGU sources apply to both existing units and any new, modified, or reconstructed units meeting the applicability criteria established in this final rule. This is consistent with the EPA's transport actions dating back to the NO_X SIP Call and the NO_X Budget Trading Program. In all CSAPR EGU trading programs, for instance, new EGUs are subject to the program, and the EPA has established provisions for the allocation of allowances to such units through ''new unit set asides.'' *See, e.g.,* 86 FR 23126. In the NO_X SIP Call, the EPA required that states cover new and existing units in the relevant source sectors through an enforceable cap or other emissions limitation. *See* 40 CFR 51.121(f). The EPA's approach of including new units in the NO_X Budget Trading Program promulgated under the EPA's CAA section 126 authority was upheld by the D.C. Circuit in *Appalachian Power* v. *EPA,* 249 F.3d 1032 (2001). As the court noted, the EPA explained in its action:

> Once EPA has determined that the emissions from the existing sources in an upwind State already make a significant contribution to one or more petitioning downwind States, any additional emissions from a new source in that upwind State would also constitute a portion of that significant contribution, unless the emissions from that new source are limited to the level of highly effective controls.

Id. at 1058 (quoting EPA 1999 RTC at 39). The court affirmed this approach: ''Indeed, it would be irrational to enable the EPA to make findings that a group of sources in an upwind state contribute to downwind nonattainment, but then preclude the EPA from regulating new sources that contribute to that same pollution.'' *Id.* at 1057–58. The EPA is implementing the same court-affirmed approach in this action because this reasoning is equally applicable to addressing interstate transport obligations under CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS.

Comment: Commenters took issue with aspects of the EPA's proposed Step 4 approach. Commenters argued the EPA could not set unit- or source-specific emissions limits or other control requirements, for EGUs or non-EGUs. Commenters argued that various aspects of the non-EGU emissions control strategy would not be feasible for their facilities or were otherwise flawed. Many industrial-source and EGU commenters argued that the EPA had not provided sufficient time for sources to come into compliance. Commenters also challenged the EGU trading program ''enhancements'' as unnecessary or beyond the EPA's authority. In this regard, commenters argued that these changes deviated from the EPA's prior approach, were unnecessary overcontrol, constituted a command-and-control approach, could not be supported on the basis of environmental justice benefits, or were otherwise unlawful for other reasons. These commenters argue that the EPA's Step 4 dynamic budget approach for EGU regulation purportedly re-defines each state's ''significant contribution'' annually and independent of any impact (or lack thereof) on air quality. They further argue that under this dynamic budgeting approach, even if a state eliminates the ''amount'' the EPA has identified as the state's significant contribution by respecting a given control period's emissions budget, sources within that state are expected to continue to make further reductions by operating their controls in a particular manner in subsequent control periods under potentially lower emissions budgets, which these commenters argue is inconsistent with case law on prior CSAPR rules.

Response: Many of these comments regarding Step 4 issues are addressed elsewhere in this document or in the *RTC* document. The EPA's authority to establish unit- or source-specific emissions rates is addressed in section IV.B.1 of this document. Responses to comments and adjustments in the timing requirements of the final rule compared to proposal are discussed in VI.A. Responses to comments and adjustments in emissions control requirements for non-EGUs in the final rule compared to proposal are in section VI.C of this document.

Responses to comments on the EGU trading program enhancements and adjustments in the final rule are contained in section VI.B of this document. However, here, in light of the changes in the emissions trading program for EGUs that we are finalizing in this action as compared to prior EGU emissions trading programs promulgated to address good neighbor obligations under other NAAQS, we set forth responses to comments specific to this topic.

The EPA finds that these comments confuse Step 3 emissions reduction stringency determinations with Step 4 implementation program details. In this rulemaking's Step 3 analysis, the EPA is measuring emissions reduction potential from improving effective emissions rates across groups of EGUs adopting applicable pollution control measures and selecting a uniform control level whose effective emissions rates deliver an acceptable outcome under the multifactor test (including a finding of no overcontrol at the selected control stringency level). The ''amounts'' defined as significant contribution to nonattainment and interference with maintenance are

[95] Section III of the Non-EGU Screening Assessment memorandum in the docket for this rulemaking describes the EPA's approach to evaluating impacts on downwind air quality, considering estimated total, maximum, and average contributions from each industry and the total number of receptors with contributions from each industry.

emissions that occur at effective emissions rates above the control stringency level selected at Step 3. That is, if a state's affected EGUs fail to reduce their effective emissions rates in line with the widely available and cost-effective control measures identified, they have therefore failed to eliminate their significant contribution to nonattainment and interference with maintenance of this NAAQS.

In this rule, the EPA is finalizing several ''enhancements'' to its existing Group 3 emissions trading program for ozone season NO_X, for reasons explained in section VI.B.1 of this document. In general, these changes will ensure that the emissions control program promulgated for EGUs at Step 4 of the EPA's 4-step interstate transport framework is in alignment with the emissions control stringency determinations the EPA made at Step 3. These enhancements reflect lessons learned through the EPA's experience with prior trading programs implemented under the good neighbor provision and ensure that the implementation of the elimination of significant contribution through an emissions trading program remains durable through a period of power sector transition. None of commenters' arguments against the EPA's authority to implement these enhancements are persuasive.

First, the EPA is not mandating that any EGU must install SCR technology. All but one of the enhancements to the trading program continue to be implemented through allowance-holding requirements under the mass-based emissions budget and trading system, including the backstop rate. (The secondary emissions limitation, which is not implemented through allowance-holding requirements under the mass-based emissions budget and trading system, and which is discussed in section VI.B.1.c.ii of this document, merely establishes a stronger deterrent for a type of conduct that was already strongly discouraged under the pre-existing trading program regulations). Nonetheless, the EPA *does* have the authority to impose unit-specific emissions limits under the exercise of its FIP authority, and it has done so in this action for non-EGU industrial sources. This authority is distinct from the EPA's title I permitting authority as discussed by certain commenters, and the scope of that permitting authority is not relevant to this action.

The quantification of emissions budgets in an allowance-based emissions trading program is one of multiple potential Step 4 implementation program design choices that states and the EPA have authority to select in securing the emissions reductions deemed necessary under Step 3. *See* CAA section 110(a)(2)(A). The EPA and the states routinely determine control stringency on an emissions rate basis in line with demonstrated pollution control opportunities, and both the EPA and the states have implementation program design discretion to determine what compliance requirements, whether expressed on a rate, mass, concentration, or percentage basis, will assure an emissions performance that reflects the control stringency required. Dynamic budgets in the Step 4 implementation of this rule are simply to ensure the trading program continues to incentivize the implementation of the EGU control strategies we find are necessary to eliminate significant contribution at Step 3. The key distinction between dynamic budget approaches and preset budget approaches is not one in stringency or authority, but rather in timing and data resources for determining the suitable mass-based limits that are as well-matched as possible to expected emissions of the affected EGUs achieving the emissions rate-based control stringency deemed necessary under Step 3 to eliminate significant contribution to nonattainment and interference with maintenance of the NAAQS.

The EPA does not agree that the administrative mechanisms by which it will implement ''dynamic budgeting'' conflict with CAA section 307(d) or the Administrative Procedure Act. The EPA is promulgating a complete FIP in this action, and the codified language of that FIP will not need to be modified as budgets are adjusted. This is because the FIP establishes the formula by which the budgets will be calculated each year (with preset budgets functioning as a floor from 2026 through 2029). This is no different than how the EPA has implemented other calculations such as updating allocations using a rolling set of data in its prior CSAPR trading programs. *See, e.g.,* 87 FR 10786. We view these actions as fundamentally ministerial in nature in that no exercise of Agency discretion is required. This process will rely on notices of availability of the relevant data in the **Federal Register**, coupled with an opportunity for the public to correct any errors they may identify in the data before the EPA sets each updated budget. See section VI.B.4 for more detail on how the EPA intends to implement dynamic budgeting. As in prior transport rules, this rule provides the opportunity for administrative appeal should an interested party identify some flaw in the EPA's updated data. See 40 CFR 78.1(b)(19)(i) (2023). That process is coupled with the availability of judicial review should the party remain dissatisfied with the EPA's resolution of complaints. *See* 40 CFR 78.1(a)(2) (requiring administrative adjudication as a prerequisite for judicial review). This administrative process has worked well throughout the history of implementing good neighbor trading programs under Part 97, and no such disputes have necessitated judicial resolution.

Further, because the dynamic budgets simply implement the stringency level reflective of the emissions control performance the EPA has determined at Step 3 for the covered EGUs, the EPA does not agree that any ''potential variables'' that are unforeseeable now could upset the basis for the formula the EPA is establishing in this action. The EPA has adjusted the role of dynamic budgeting in this final rule as compared to the proposal. See sections VI.B.1 and VI.B.4 of the preamble. In particular, the EPA is applying an approach to budget setting through 2029 that will use the greater of either a preset budget based on information known to the Agency at the time of this action, or the dynamic budget to be calculated based upon future data yet to be reported. Thus, through 2029 the imposition of a dynamic budget would only increase rather than diminish the emissions allowed for that control period compared to the preset budgets established in this action. In addition, the EPA will determine each state's dynamic budget based on a rolling 3-year average of the state's heat input, thus smoothing out trends to account for interannual variability in demand and heat input and provide greater certainty and predictability as the budget updates from year to year.

Moreover, the EPA does not agree that the EPA is constrained by the statute to only implement good neighbor obligations through fixed, unchanging, mass-based emissions budgets. *See* section III.B.1 of this document. The EPA finds good reason based on its experience with trading programs using fixed budgets why this approach does not necessarily ensure the elimination of significant contribution in perpetuity. The EPA has already once adjusted its historical approach to better account for known, upcoming changes in the EGU fleet to ensure mass-based emissions budgets adequately incentivize the control strategy determined at Step 3. This adjustment was introduced in the Revised CSAPR Update. *See* 82 FR

23121–22.[96] The EPA now believes it is appropriate to ensure in a more comprehensive manner, and in perpetuity, that the mass-based emissions budget incentivize continuing implementation of the Step 3 control strategies to ensure significant contribution is eliminated in all upwind states and remains so. The dynamic budget-setting process preserves these incentives over time by calculating the state emissions budgets for each future control period so as to reflect the Step 3 control stringency finalized in this rule as applied to the most current information regarding the composition of the power sector in the control period. This is fully analogous in material respect to an approach to implementation at Step 4 that relies on application of unit-specific emissions rates that apply in perpetuity. The availability of unit-specific emissions rates as a means to eliminate significant contribution is discussed in further detail in section III.B.1 of this document. The EPA also explained this in the proposal. *See* 87 FR 20095–96. The EPA does not agree that either dynamic budgeting or the backstop rate results in overcontrol. *See* section V.D.4 of this document.

The EPA is enhancing the trading program to help reconcile the approach of using mass-based budgets to achieve the elimination of significant contribution with the *Wisconsin* directive to provide a complete remedy under the good neighbor provision. This approach also better accords with ensuring measures to attain and maintain the NAAQS are permanent and enforceable. The dynamic budget approach recognizes that the uncertainty around future fleet conditions increases the further into the future one looks (and the EPA must look further under the ''full remedy'' directive). To preserve its ability to successfully implement its identified Step 3 stringency, the EPA is designing the implementation of this rule's emissions control program to benefit from the future availability of better data from the regulated sources to inform its application of its stringency measures identified in this rule.

The EPA does not agree with commenters who suggest that these enhancements are undertaken for the purpose of a non-statutory ''environmental justice'' objective. As explained in section VI.B of this document, certain enhancements to the trading program ensure that each EGU is adequately incentivized to continuously operate its emissions controls once those controls are installed. One commenter contends that the backstop emissions rate is not authorized based on environmental justice considerations, since it is not necessary and is overcontrol with respect to the EPA's statutory authority to address good neighbor obligations. But the EPA disagrees with the premise that these enhancements are unrelated to the statutory obligation to eliminate significant contribution. Taking measures to ensure that each upwind source covered by an emissions trading program to eliminate significant contribution is operating its installed pollution controls on a more continuous and consistent basis throughout the ozone season is entirely appropriate in light of the daily nature of the ozone problem, the impacts to public health and the environment from ozone that can occur through short-term exposure (*e.g.,* over a course of hours), the fact that the 2015 ozone NAAQS is expressed as an 8-hour average, and that only a small number of days in excess of the ozone NAAQS are necessary to place a downwind area in nonattainment, resulting in continuing and/or increased regulatory burden on the downwind jurisdiction. *See* section III.A of this document.

Further, the D.C. Circuit has held that the EPA must ensure that its good neighbor program has eliminated *each* state's sources from continuing to significantly contribute to nonattainment or interfere with maintenance in downwind states. *See North Carolina,* 531 F.3d at 921. The commenters neglect to acknowledge the scenario that has frequently borne out in prior programs, in which future fleet changes that were not known at the time of initial setting of state emissions budgets produce unexpected ''hot air'' in the budget that, if unaccounted for, other units can exploit to forgo identified cost-effective mitigation measures deemed necessary to eliminate significant contribution to nonattainment and interference with maintenance of the NAAQS.

The EPA's experience is that fixed mass-based budgets that are determined based only on the profile of the power sector at the time the rule is promulgated, and without any additional requirement for pollution controls operation, can become quickly obsolete if the composition of the group of affected EGUs changes notably over time. As some sources retire, other sources relax their operation of NO_X controls in response to a growing surplus of allowances, even though the EPA had concluded that ongoing operation of those controls is necessary to meet the statutory good neighbor requirements. For instance, under the CSAPR Update, in the 2018–2020 period, the fixed budget approach enabled large, frequently run units with existing SCR controls to not optimize those controls even though the EPA's assessment (as reflected in the CSAPR Update) was that the optimization of those controls was necessary to eliminate significant contribution. This deterioration in emission rate at SCR-controlled coal plants was widely observed across the CSAPR Update geography as the program advanced into later years and allowance price deteriorated. Whereas coal sources with SCR performed, on average, at a 0.086 lb/mmBtu rate in 2017, that same set of sources saw their environmental performance worsen to a 0.099 lb/mmBtu rate in 2020. A Congressional Research Service Report on EPA prior CSAPR trading programs indicated low prices observed in later years ''could lead to some decisions not to run some pollution controls at maximum output. This would, in turn, lead to higher emissions''.[97]

In the case of individual units, this deterioration in performance can be quite pronounced and can occur as quickly as the second or third control period, as in the case of Miami Fort Unit 7 in Ohio in 2019, discussed in section V.B of this document. The absence of a sufficient incentive under the trading program to implement the identified control strategy at Step 3 can even result in collective emissions that exceed state-wide assurance levels. The EPA established these levels beginning with CSAPR, above which enhanced allowance-surrender requirements are triggered, in an effort to ensure sources in each state are held to eliminate their own significant contribution, which the D.C. Circuit has held is legally required, *see North Carolina,* 531 F.3d 896, 906–08 (D.C. Cir. 2008). In four instances over the course of the 2019, 2020, and

[96] Further, in the Revised CSAPR Update, the EPA acknowledged that a mechanism like dynamic budgeting could be appropriate for a transport rule with longer time horizons. We stated in response to comments that we were not ''in this action, including an adjustment mechanism to further adjust state emission budgets to account for currently unknown or uncertain retirements after the finalization of this rule . . . . EPA observes that the commenter's proposed mechanism would become increasingly valuable for rules where the timeframe extends further into the future where retirement uncertainty is higher.'' Revised CSAPR Update Response to Comments, EPA–HQ–OAR–2020–0272–219, at 153.

[97] Shouse, Kate. ''The Clean Air Act's Good Neighbor Provision: Overview of Interstate Air Pollution Control''. Congressional Research Services. August 30, 2018. Available at *https://sgp.fas.org/crs/misc/R45299.pdf.*

2021 control periods under the CSAPR Update, sources in Mississippi and Missouri collectively exceeded their state-wide assurance levels in part due to deterioration in emissions performance that can be attributed to a glut of allowances within the CSAPR Update. See section VI.B.8 of the preamble.

Thus, while this trading program structure may achieve some environmental benefit through fixed emissions budgets for initial control periods, over time those fixed budgets cease to have their intended effect, and remaining operating facilities can, and have, increased emissions or even discontinued the operation of their emissions controls. This, in turn, can lead to the continuation (or re-emergence) of significant contribution in terms of a recurrence of excessive emissions that had been slated for permanent elimination under the EPA's determinations at Step 3. Although the EPA has always intended for its trading programs to provide flexibility, the Agency did not expect and has certainly never endorsed the use of that flexibility to stop the operation of controls that have already been installed. *See, e.g.,* 76 FR 48256–57 (''[I]t would be inappropriate for a state linked to downwind nonattainment or maintenance areas to stop operating existing pollution control equipment (which would increase their emissions and contribution).''). Despite the EPA's expectations in CSAPR, the historical data establishes a real risk of ''under-control'' if the existing trading framework is not improved upon. *See EME Homer City,* 572 U.S. at 523 (''[T]he Agency also has a statutory obligation to avoid 'under-control,' *i.e.,* to maximize achievement of attainment downwind.'').

This result is also inconsistent with the statutory mandate to ''prohibit'' significant contribution and interference with maintenance of the NAAQS in downwind states, as evidenced most clearly in CAA section 126, which makes it unlawful for a source ''to *operate* more than three months after [a finding that the source emits or would emit in violation of the good neighbor provision] has been made with respect to it.'' 42 U.S.C. 7426(c)(2) (emphasis added). *See also North Carolina,* 531 F.3d at 906–08 (each state must be held to the elimination of its own significant contribution). The purpose of the Agency's interstate trading programs under the good neighbor provision is to afford sources some flexibility in achieving region-wide emissions reductions; however, there is no justification that can be sustained within that framework for sources in certain areas within that region, or during periods of high ozone when good emissions performance is most essential, to emit at levels well in excess of the EPA's Step 3 determinations of significant contribution. Significant contribution, according to the statute, must be ''prohibited.'' CAA section 110(a)(2)(D)(i).

Thus, these trading program enhancements are within the EPA's authority under CAA section 110(a)(2)(D)(i)(I) to eliminate interstate ozone pollution that significantly contributes to nonattainment or interferes with maintenance in downwind states. These enhancements ensure the elimination of significant contribution across all upwind states and throughout each ozone season. We observe in the Ozone Transport Policy Analysis Final Rule TSD, section E, that the trading program enhancements may also benefit underserved and overburdened communities downwind of EGUs in the covered geography of the final rule. See section VI.B of this document. This does not detract from the statutorily-authorized basis for these changes, and the EPA finds nothing impermissible in acknowledging the reality of these potential benefits for underserved and overburdened communities.

The EPA appreciates a commenter's concern that our actions be legally defensible. The EPA acknowledges that the changes to the trading program structure for implementing good neighbor obligations discussed here constitute a change in the policy underlying its prior transport-rule trading programs for EGUs. However, the EPA is confident that these changes are in compliance with the holdings in judicial decisions reviewing prior transport rules. The fact that the EPA is making changes does not somehow render these enhancements legally impermissible or even subject to a heightened standard of review. *See FCC* v. *Fox Television Stations,* 556 U.S. 502, 514 (2009) (''We find no basis in the Administrative Procedure Act or in our opinions for a requirement that all agency change be subjected to more searching review.''). We have explained previously and elsewhere in the record that there are ''good reasons'' for the ''new policy.'' *See id.* at 515. And, we are of course fully aware that we have changed our position. *See id.* at 514–15. Specifically, we have gone from previously treating fixed, mass-based budgets as sufficient to eliminate significant contribution, to an approach for purposes of the 2015 ozone NAAQS reflecting a more nuanced understanding of how an emissions trading program that does not properly anticipate future fleet conditions at Step 4 may fail to achieve the elimination of emissions that should be prohibited based on our findings at Step 3. Further, we find there to be no ''serious reliance interests'' that have been or even could have been ''engendered'' by any prior policy on these issues, *see id.* at 515–16. The EPA is implementing these enhancements for the first time with respect to a new obligation—good neighbor requirements for the 2015 ozone NAAQS. No party reasonably could have invested substantial resources to-date to comply with an obligation that was heretofore undefined; and no commenter has supplied any information to the contrary.

2. FIP Authority for Each State Covered by the Rule

On October 26, 2015, the EPA promulgated a revision to the 2015 8-hour ozone NAAQS, lowering the level of both the primary and secondary standards to 0.070 parts per million (ppm).[98] These revisions of the NAAQS, in turn, established a 3-year deadline for states to provide SIP submissions addressing infrastructure requirements under CAA sections 110(a)(1) and CAA 110(a)(2), including the good neighbor provision, by October 1, 2018. If the EPA makes a determination that a state failed to submit a SIP, or if EPA disapproves a SIP submission, then the EPA is obligated under CAA section 110(c) to promulgate a FIP for that state within 2 years. For a more detailed discussion of CAA section 110 authority and timelines, refer to section III.C of this document.

The EPA is finalizing this FIP action now to address 23 states' good neighbor obligations for the 2015 ozone NAAQS.[99] For each state for which the EPA is finalizing this FIP, the EPA either issued final findings of failure to submit or has issued a final disapproval of that state's SIP submission.

Several commenters asserted that the sequence of the EPA's actions, and in particular, the timing of its proposed FIP (which was signed on February 28,

[98] *National Ambient Air Quality Standards for Ozone,* Final Rule, 80 FR 65292 (Oct. 26, 2015). Although the level of the standard is specified in the units of ppm, ozone concentrations are also described in parts per billion (ppb). For example, 0.070 ppm is equivalent to 70 ppb.

[99] The EPA notes that it is subject to, and has met through this action, a consent decree deadline to promulgate FIPs addressing 2015 ozone NAAQS good neighbor obligations for the states of Pennsylvania, Utah, and Virginia. *See Sierra Club et al.* v. *Regan,* No. 3:22–cv–01992–JD (N.D. Cal. entered January 24, 2023).

2022, and published on April 6, 2022) in relation to the timing of its proposed SIP disapprovals (most of which were published on February 22, 2022, four of which were published on May 24, 2022, and one of which was published on October 25, 2022), was either unlawful or unreasonable in light of the sequence of steps required under CAA section 110(k) and (c).

These commenters are incorrect. As an initial matter, concerns about the timing or substance of the EPA's actions on the SIP submittals are beyond the scope of this action. Nor are the timing or contents of merely proposed actions to be considered final agency actions or subject to judicial review. *See In re Murray Energy,* 788 F.3d 330 (D.C. Cir. 2015). With these principles in mind, the timing of this final action is lawful under the Act. First, the EPA is not required to wait to propose a FIP until after the Agency proposes or finalizes a SIP disapproval or makes a finding of failure to submit.[100] CAA section 110(c) authorizes the EPA to promulgate a FIP ''at any time within 2 years'' of a SIP disapproval or making a finding of failure to submit. The Supreme Court recognized in *EME Homer City* that the EPA is not obligated to first define a state's good neighbor obligations or give the state an additional opportunity to submit an approvable SIP before promulgating a FIP: ''EPA is not obliged to wait two years or postpone its action even a single day: The Act empowers the Agency to promulgate a FIP 'at any time' within the two-year limit.'' [101] Thus, the EPA may promulgate a FIP contemporaneously with or immediately following predicate final SIP disapproval (or finding no SIP was submitted). To accomplish this, the EPA must necessarily be able to propose a FIP prior to taking final action to disapprove a SIP or make a finding of failure to submit.

Second, and more importantly, the EPA has established predicate authority to promulgate FIPs for all of the covered states through its action with respect to the relevant SIP submittals. A brief history of these actions follows:

On February 22, 2022, the EPA proposed to disapprove 19 good neighbor SIP submissions (Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Ohio, Oklahoma, Tennessee, Texas, West Virginia, Wisconsin).[102] Alabama subsequently withdrew its SIP submission and re-submitted a SIP submission on June 22, 2022. The EPA proposed to disapprove that SIP submittal on October 25, 2022.[103] The EPA proposed to disapprove good neighbor SIP submissions for four additional states, California, Nevada, Utah, and Wyoming, on May 24, 2022.[104]

Subsequently, on January 31, 2023, the EPA Administrator signed a single disapproval action for all of the above states, with the exception of Tennessee and Wyoming.[105] This action established the EPA's authority to promulgate FIPs for the disapproved states. (As explained in section IV.F of this document, the Agency is deferring action at this time for Tennessee and Wyoming with respect to its proposed FIP actions for those states. As discussed in section IV.F of this document, the EPA's most recent modeling and air quality analysis indicates that several states may be linked to downwind receptors for which we had not previously proposed disapproval or FIP action. The EPA anticipates addressing remaining interstate transport obligations for the 2015 ozone NAAQS for these in a subsequent rulemaking.)

Additionally, the EPA has taken action that has triggered the EPA's obligation under CAA section 110(c) to promulgate FIPs addressing the good neighbor provision for several downwind states. On December 5, 2019, the EPA published a rule finding that seven states (Maine, New Mexico, Pennsylvania, Rhode Island, South Dakota, Utah, and Virginia) failed to submit or otherwise make complete submissions that address the requirements of CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS.[106] This finding triggered a 2-year deadline for the EPA to issue FIPs to address the good neighbor provision for these states by January 6, 2022. As the EPA has subsequently received and taken final action to approve good neighbor SIPs from Maine, Rhode Island, and South Dakota,[107] the EPA currently has authority under the December 5, 2019, findings of failure to submit to issue FIPs for New Mexico, Pennsylvania, Utah, and Virginia. In this final rule, the EPA is issuing FIP requirements for Pennsylvania, Utah, and Virginia.[108]

Further information on the procedural history establishing the EPA's authority for this final rule is provided in a document in the docket.[109]

[100] The EPA notes there are three consent decrees to resolve three deadline suits related to EPA's duty to act on good neighbor SIP submissions for the 2015 ozone NAAQS. In *New York et al.* v. *Regan, et al.* (No. 1:21–CV–00252, S.D.N.Y.), the EPA agreed to take final action on the 2015 ozone NAAQS good neighbor SIP submissions from Indiana, Kentucky, Michigan, Ohio, Texas, and West Virginia by April 30, 2022; however, if the EPA proposes to disapprove any SIP submissions and proposes a replacement FIP by February 28, 2022, then EPA's deadline to take final action on that SIP submission is extended to December 30, 2022. In *Downwinders at Risk et al.* v. *Regan* (No. 21–cv–03551, N.D. Cal.), the EPA agreed to take final action on the 2015 ozone NAAQS good neighbor SIP submissions from Alabama, Arkansas, Connecticut, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Tennessee, Texas, West Virginia, and Wisconsin by April 30, 2022; however, if the EPA proposes to disapprove any of these SIP submissions and proposes a replacement FIP by February 28, 2022, then the EPA's deadline to take final action on that SIP submission is December 30, 2022. In this CD, the EPA also agreed to take final action on Hawaii's SIP submission by April 30, 2022, and to take final action on the SIP submissions of Arizona, California, Montana, Nevada, and Wyoming by December 15, 2022. In *Our Children's Earth Foundation* v. *EPA* (No. 20–8232, S.D.N.Y.), the EPA agreed to take final action on the 2015 ozone NAAQS good neighbor SIP submission from New York by April 30, 2022; however, if the EPA proposes to disapprove New York's SIP submission and proposes a replacement FIP by February 28, 2022, then the EPA's deadline to take final action on New York's SIP submission is extended to December 30, 2022. By stipulation of the parties, the December 15, 2022, date in all three of these consent decrees was extended to January 31, 2023. By further stipulation of the parties in the *Downwinders at Risk* case, the January 31, 2023, date was further extended to December 15, 2023 for the EPA to act on the SIP submissions from the states of Arizona, Tennessee, and Wyoming.

[101] *See EPA* v. *EME Homer City Generation, L.P.,* 572 U.S. 489, 509 (2014) (citations omitted).

[102] *See* 87 FR 9463 (Maryland); 87 FR 9484 (New Jersey, New York); 87 FR 9498 (Kentucky); 87 FR 9516 (West Virginia); 87 FR 9533 (Missouri); 87 FR 9545 (Alabama, Mississippi, Tennessee); 87 FR 9798 (Arkansas, Louisiana, Oklahoma, Texas); 87 FR 9838 (Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin).

[103] *See* 87 FR 64412.

[104] *See* 87 FR 31443 (California); 87 FR 31485 (Nevada); 87 FR 31470 (Utah); 87 FR 31495 (Wyoming).

[105] *See* 88 FR 9336.

[106] *Findings of Failure To Submit a Clean Air Act Section 110 State Implementation Plan for Interstate Transport for the 2015 Ozone National Ambient Air Quality Standards (NAAQS),* 84 FR 66612 (December 5, 2019, effective January 6, 2020).

[107] *Air Plan Approval; Maine and New Hampshire; 2015 Ozone NAAQS Interstate Transport Requirements,* 86 FR 45870 (August 17, 2021); *Air Plan Approval; Rhode Island; 2015 Ozone NAAQS Interstate Transport Requirements,* 86 FR 70409 (December 10, 2021); *Promulgation of State Implementation Plan Revisions; Infrastructure Requirements for the 2015 Ozone National Ambient Air Quality Standards; South Dakota; Revisions to the Administrative Rules of South Dakota,* 85 FR 29882 (May 19, 2020).

[108] *WildEarth Guardians* v. *Regan,* No. 1:22–cv–00174 (D.N.M. entered Aug. 16, 2022); *Sierra Club et al.* v. *EPA,* No. 3:22–cv–01992 (N.D. Cal. entered Jan. 24, 2023).

[109] *See* ''Final Rule: Status of CAA Section 110(a)(2)(D)(i)(I) SIP Submissions for the 2015 Ozone NAAQS for States Covered by the Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards.'' This document updates a prior document of the same title provided

Continued

While the EPA's previous actions are sufficient to establish that the EPA's promulgation of this FIP action at this time is lawful, the timing of this action is all the more reasonable in light of the need for the EPA to address good neighbor obligations consistent with the rest of title I of the CAA. In particular, the D.C. Circuit in *Wisconsin* held that states and the EPA are obligated to fully address good neighbor obligations for ozone ''as expeditiously as practical'' and in no event later than the next relevant downwind attainment dates found in CAA section 181(a).[110] In *Maryland* v. *EPA,* the D.C. Circuit made clear that *Wisconsin'*s and *North Carolina'*s holdings are fully applicable to the Marginal area attainment date for the 2015 ozone NAAQS,[111] which fell on August 3, 2021.[112] As discussed in section VI.A of this document, by finalizing this action now, the EPA is able to implement initial required emissions reductions to eliminate significant contribution by the 2023 ozone season, which is the last full ozone season before the next attainment date, the Moderate area attainment date of August 3, 2024. The *Wisconsin* court emphasized that the EPA has the authority under CAA section 110 to structure and time its actions in a manner such that the Agency can ensure necessary reductions are achieved in alignment with the downwind attainment schedule, and that is precisely what the EPA is doing here.[113] The EPA provides further response to the comments on this issue in section 1 of the *RTC* document.

C. Other CAA Authorities for This Action

1. Withdrawal of Proposed Error Correction for Delaware

The EPA proposed at 87 FR 20036 to make an error correction under CAA section 110(k)(6) of its May 1, 2020, approval at 85 FR 25307 of the interstate transport elements for Delaware's October 11, 2018, and December 26, 2019, ozone infrastructure SIP submissions as satisfying the requirements of CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS. The EPA proposed to determine that the basis for the prior SIP approval was invalidated by the Agency's more recent technical evaluation of air quality modeling performed in support of the proposed rule,[114] and that Delaware had unresolved interstate transport obligations for the 2015 ozone NAAQS. The EPA also proposed to issue a FIP for Delaware given these unresolved interstate transport obligations. However, based on the updated air quality modeling described in section IV.F. of this document and the technical assessment that informs this final rule, the EPA finds that Delaware is not projected to be linked to any downwind receptor above the 1 percent of the NAAQS threshold in 2023. Thus, based on the record before the Agency now, the original approval of Delaware's SIP submission was not in error, and the EPA is withdrawing its proposed error correction and proposed FIP for Delaware.

2. Application of Rule in Indian Country and Necessary or Appropriate Finding

The EPA is finalizing its determination that this rule will be applicable in all areas of Indian country (as defined at 18 U.S.C. 1151) within the covered geography of the final rule, as defined in this section. Certain areas of Indian country within the geography of the rule are or may be subject to state implementation planning authority. Other areas of Indian country within that geography are subject to tribal planning authority, although none of the relevant tribes have as yet sought eligibility to administer a tribal plan to implement the good neighbor provision.[115] As described later, the EPA is including all areas of Indian country within the covered geography, notwithstanding whether those areas are currently subject to a state's implementation planning authority or the potential planning authority of a tribe.

a. Indian Country Subject to Tribal Jurisdiction

With respect to areas of Indian country not currently subject to a state's implementation planning authority—*i.e.,* Indian reservation lands (with the partial exception of reservation lands located in the State of Oklahoma, as described further in this section) and other areas of Indian country over which the EPA or a tribe has demonstrated that a tribe has jurisdiction—the EPA here makes a ''necessary or appropriate'' finding that direct Federal implementation of the rule's requirements is warranted under CAA section 301(d)(4) and 40 CFR 49.11(a) (the areas of Indian country subject to this finding will be referred to as the CAA section 301(d) FIP areas). Indian Tribes may, but are not required to, submit tribal plans to implement CAA requirements, including the good neighbor provision. Section 301(d) of the CAA and 40 CFR part 49 authorize the Administrator to treat an Indian Tribe in the same manner as a state (*i.e.,* TAS) for purposes of developing and implementing a tribal plan implementing good neighbor obligations. *See* 40 CFR 49.3; *see also* ''Indian Tribes: Air Quality Planning and Management,'' hereafter ''Tribal Authority Rule'' (63 FR 7254, February 12, 1998). The EPA is authorized to directly implement the good neighbor provision in the 301(d) FIP areas when it finds, consistent with the authority of CAA section 301—which the EPA has exercised in 40 CFR 49.11—that it is necessary or appropriate to do so.[116]

at proposal (Document no. EPA–HQ–OAR–2021–0668–0131).

[110] *Wisconsin* v. *EPA,* 938 F.3d 303, 313–14 (D.C. Cir. 2019) (citing *North Carolina* v. *EPA,* 531 F.3d 896, 911–13 (D.C. Cir. 2008).

[111] *Maryland* v. *EPA,* 958 F.3d 1185, 1203–04 (D.C. Cir. 2020).

[112] *See* CAA section 181(a); 40 CFR 51.1303; *Additional Air Quality Designations for the 2015 Ozone National Ambient Air Quality Standards,* 83 FR 25776 (June 4, 2018, effective August 3, 2018).

[113] 938 F.3d at 318 (''When EPA determines a State's SIP is inadequate, EPA presumably must issue a FIP that will bring that State into compliance before upcoming attainment deadlines, even if the outer limit of the statutory timeframe gives EPA more time to formulate the FIP.'') (citing *Sierra Club* v. *EPA,* 294 F.3d 155, 161 (D.C. Cir. 2002)).

[114] *See* the Air Quality Modeling Proposed Rule TSD in the docket for this rule.

[115] We note that, consistent with the EPA's prior good neighbor actions in California, the regulatory ozone monitor located on the Morongo Band of Mission Indians (''Morongo'') reservation is a projected downwind receptor in 2023. *See* monitoring site 060651016 in Table IV.D.–1. We also note that the Temecula, California, regulatory ozone monitor is a projected downwind receptor in 2023 and in past regulatory actions has been deemed representative of air quality on the Pechanga Band of Luiseño Indians (''Pechanga'') reservation. *See, e.g., Approval of Tribal Implementation Plan and Designation of Air Quality Planning Area; Pechanga Band of Luiseño Mission Indians,* 80 FR 18120, at 18121–18123 (April 3, 2015); *see also* monitoring site 060650016 in Table IV.D–1. The presence of receptors on, or representative of, the Morongo and Pechanga reservations does not trigger obligations for the Morongo and Pechanga Tribes. Nevertheless, these receptors are relevant to the EPA's assessment of any linked upwind states' good neighbor obligations. *See, e.g., Approval and Promulgation of Air Quality State Implementation Plans; California; Interstate Transport Requirements for Ozone, Fine Particulate Matter, and Sulfur Dioxide,* 83 FR 65093 (December 19, 2018). Under 40 CFR 49.4(a), tribes are not subject to the specific plan submittal and implementation deadlines for NAAQS-related requirements, including deadlines for submittal of plans addressing transport impacts.

[116] *See Arizona Pub. Serv. Co.* v. *U.S. E.P.A.,* 562 F.3d 1116, 1125 (10th Cir. 2009) (stating that 40 CFR 49.11(a) ''provides the EPA discretion to determine what rulemaking is necessary or appropriate to protect air quality and requires the EPA to promulgate such rulemaking''); *Safe Air For Everyone* v. *U.S. Env't Prot. Agency,* No. 05–73383, 2006 WL 3697684, at *1 (9th Cir., Dec. 15, 2006) (''The statutes and regulations that enable EPA to regulate air quality on Indian reservations provide EPA with broad discretion in setting the content of such regulations.'').

The EPA hereby finds that it is both necessary and appropriate to regulate all new and existing EGU and industrial sources meeting the applicability criteria set forth in this rule in all of the 301(d) FIP areas that are located within the geographic scope of coverage of the rule. For purposes of this finding, the geographic scope of coverage of the rule means the areas of the United States encompassed within the borders of the states the EPA has determined to be linked at Steps 1 and 2 of the 4-step interstate transport framework.[117] For EGU applicability criteria, *see* section VI.B of this document; for industrial-source applicability criteria, *see* section VI.C of this document. To EPA's knowledge, only one existing EGU or industrial source is located within the CAA section 301(d) FIP areas: the Bonanza Power Plant, an EGU source, located on the Uintah and Ouray Reservation, geographically located within the borders of Utah.

This finding is consistent with the EPA's prior good neighbor rules. In prior rulemakings under the good neighbor provision, the EPA has included all areas of Indian country within the geographic scope of those FIPs, such that any new or existing sources meeting the rules' applicability criteria would be subject to the rule irrespective of whether subject to state or tribal underlying CAA planning authority. In CSAPR, the CSAPR Update, and the Revised CSAPR Update, the scope of the emissions trading programs established for EGUs extended to cover all areas of Indian country located within the geographic boundaries of the covered states. In these rules, at the time of their promulgation, no existing units were located in the covered areas of Indian country; under the general applicability criteria of the trading programs, however, any new sources locating in such areas would become subject to the programs. Thus, the EPA established a separate allowance allocation that would be available for any new units locating in any of the relevant areas of Indian country. *See, e.g.,* 76 FR 48293 (describing the CSAPR methodology of allowance allocation under the ''Indian country new unit set-aside'' provisions); *see also id.* at 48217 (explaining the EPA's source of authority for directly regulating in relevant areas of Indian country as necessary or appropriate). Further, in any action in which the EPA subsequently approved a state's SIP submittal to partially or wholly replace the provisions of a CSAPR FIP, the EPA has clearly delineated that it will continue to administer the Indian country new unit set aside for sources in any areas of Indian country geographically located within a state's borders and not subject to that state's CAA planning authority, and the state may not exercise jurisdiction over any such sources. *See, e.g.,* 82 FR 46674, 46677 (October 6, 2017) (approving Alabama's SIP submission establishing a state CSAPR trading program for ozone season NO_X, but providing, ''The SIP is not approved to apply on any Indian reservation land or in any other area where EPA or an Indian tribe has demonstrated that a tribe has jurisdiction.'').

In this rule, the EPA is taking an approach similar to the prior CSAPR rulemakings with respect to regulating sources in the CAA section 301(d) FIP areas.[118] The EPA believes this approach is necessary and appropriate for several reasons. First, the purpose of this rule is to address the interstate transport of ozone on a national scale, and the technical record establishes that the nonattainment and maintenance receptors located throughout the country are impacted by sources of ozone pollution on a broad geographic scale. The upwind regions associated with each receptor typically span at least two, and often far more, states. Within the broad upwind region covered by this rule, the EPA is applying—consistent with the methodology of allocating upwind responsibility in prior transport rules going back to the NO_X SIP Call—a uniform level of control stringency (as determined separately for linkages existing in 2023, and linkages persisting in 2026). (*See* section V of this document for a discussion of EPA's determination of control stringency for this rule.) Within this approach, consistency in rule requirements across all jurisdictions is vital in ensuring the remedy for ozone transport is, in the words of the Supreme Court, ''efficient and equitable,'' 572 U.S. 489, 519. In particular, as the Supreme Court found in *EME Homer City Generation,* allocating responsibility through uniform levels of control across the entire upwind geography is ''equitable'' because, by imposing uniform cost thresholds on regulated States, the EPA's rule subjects to stricter regulation those States that have done relatively less in the past to control their pollution. Upwind States that have not yet implemented pollution controls of the same stringency as their neighbors will be stopped from free riding on their neighbors' efforts to reduce pollution. They will have to reduce their emissions by installing devices of the kind in which neighboring States have already invested. *Id.*

In the context of addressing regional-scale ozone transport in this rule, the importance of a uniform level of stringency that extends to and includes the CAA section 301(d) FIP areas geographically located within the boundaries of the linked upwind states carries significant force. Failure to include all such areas within the scope of the rule creates a significant risk that these areas may be targeted for the siting of facilities emitting ozone-precursor pollutants, to avoid the regulatory costs that would be imposed under this rule in the surrounding areas of state jurisdiction. Electricity generation or the production of other goods and commodities may become more cost-competitive at any EGU or industrial sources not subject to the rule but located in a geography where the same types of sources are subject to the rule. For instance, the affected EGU source located on the Uintah and Ouray Reservation of the Ute Tribe is in an area that is interconnected with the western electricity grid and is owned and operated by an entity that generates and provides electricity to customers in several states. It is both necessary and appropriate, in the EPA's view, to avoid creating, via this rule, a structure of incentives that may cause generation or production—and the associated NO_X emissions—to shift into the CAA section 301(d) FIP areas to escape regulation needed to eliminate interstate transport under the good neighbor provision.

The EPA finds it is appropriate to directly implement the rule's requirements in the CAA section 301(d) FIP areas in this action rather than at a later date. Tribes have the opportunity to seek treatment as a state (TAS) and to undertake tribal implementation plans under the CAA. To date, the one tribe which could develop and seek approval of a tribal implementation plan to address good neighbor obligations with respect to an existing EGU in the CAA section 301(d) FIP areas for the 2015 ozone NAAQS (or for any other NAAQS), the Ute Indian Tribe of the Uintah and Ouray Reservation, has not

[117] With respect to any industrial sources located in the CAA section 301(d) FIP areas, the geographic scope of coverage of this rule does not include those states for which the EPA finds, based on air quality modeling, that no further linkage exists by the 2026 analytic year at Steps 1 and 2. The states in this rule not linked in 2026 are Alabama, Minnesota, and Wisconsin.

[118] *See* section VI.B.9 of this document for a discussion of revisions that are being made in this rulemaking regarding the point in the allowance allocation process at which the EPA would establish set-asides of allowances for units in Indian country not subject to a state's CAA implementation planning authority.

expressed an intent to do so. Nor has the EPA heard such intentions from any other tribe, and it would not be reasonable to expect tribes to undertake that planning effort, particularly when no existing sources are currently located on their lands. Further, the EPA is mindful that under court precedent, the EPA and states bear an obligation to fully implement any required emissions reductions to eliminate significant contribution under the good neighbor provision as expeditiously as practicable and in alignment with downwind areas' attainment schedule under the Act. As discussed in section VI.A of this document, the EPA is implementing certain required emissions reductions by the 2023 ozone season, the last full ozone season before the 2024 Moderate area attainment date, and other key additional required emissions reductions by the 2026 ozone season, the last full ozone season before the 2027 Serious area attainment date. Absent the application of this FIP in the CAA section 301(d) FIP areas, NO_X emissions from any existing or new EGU or non-EGU sources located in, or locating in, the CAA section 301(d) FIP areas within the covered geography of the rule would remain unregulated for purposes of CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS and could continue or potentially increase. This would be inconsistent with the EPA's overall goal of aligning good neighbor obligations with the downwind areas' attainment schedule and to achieve emissions reductions as expeditiously as practicable.

Further, the EPA recognizes that Indian country, including the CAA section 301(d) FIP areas, is often home to communities with environmental justice concerns, and these communities may bear a disproportionate level of pollution burden as compared with other areas of the United States. The EPA's Fiscal Year 2022–2026 Strategic Plan [119] includes an objective to promote environmental justice at the Federal, Tribal, state, and local levels and states: ''Integration of environmental justice principles into all EPA activities with Tribal governments and in Indian country is designed to be flexible enough to accommodate EPA's Tribal program activities and goals, while at the same time meeting the Agency's environmental justice goals.'' As described in section X.F of this document, the EPA offered Tribal consultation to 574 Tribes in April of 2022 and received no requests for Tribal consultation after publication of the proposed rulemaking. By including all areas of Indian country within the covered geography of the rule, the EPA is advancing environmental justice, lowering pollution burdens in such areas, and preventing the potential for ''pollution havens'' to form in such areas as a result of facilities seeking to locate there to avoid the requirements that would otherwise apply outside of such areas under this rule.

Therefore, to ensure timely alignment of all needed emissions reductions within the timetables of this rule, to ensure equitable distribution of the upwind pollution reduction obligation across all upwind jurisdictions, to avoid perverse economic incentives to locate sources of ozone-precursor pollution in the CAA section 301(d) FIP areas, and to deliver greater environmental justice to tribal communities in line with Executive Order 13985: Advancing Racial Equity and Support for Underserved Communities Through the Federal Government,[120] the EPA finds it both necessary and appropriate that all existing and new EGU and industrial sources that are located in the CAA section 301(d) FIP areas within the geographic boundaries of the covered states, and which would be subject to this rule if located within areas subject to state CAA planning authority, should be included in this rule. The EPA issues this finding under CAA section 301(d)(4) of the Act and 40 CFR 49.11. Further, to avoid ''unreasonable delay'' in promulgating this FIP, as required under section 49.11, the EPA makes this finding now, to align emissions reduction obligations for any covered new or existing sources in the CAA section 301(d) FIP areas with the larger schedule of reductions under this rule. Because all other covered EGU and non-EGU sources within the geography of this rule would be subject to emissions reductions of uniform stringency beginning in the 2023 ozone season, and as necessary to fully and expeditiously address good neighbor obligations for the 2015 ozone NAAQS, there is little benefit to be had by not including the CAA section 301(d) FIP areas in this rule now and a potentially significant downside to not doing so.

The Agency recognizes that Tribal governments may still choose to seek TAS to develop a Tribal plan with respect to the obligations under this rule, and this determination does not preclude the tribes from taking such actions. Although the formal tribal consultation process associated with this action has concluded, the EPA is willing and available to engage with any tribe as this rule is implemented.

b. Indian Country Subject to State Implementation Planning Authority

Following the U.S. Supreme Court decision in *McGirt* v. *Oklahoma,* 140 S. Ct. 2452 (2020), the Governor of the State of Oklahoma requested approval under section 10211(a) of the Safe, Accountable, Flexible, Efficient Transportation Equity Act of 2005: A Legacy for Users, Public Law 109–59, 119 Stat. 1144, 1937 (August 10, 2005) (''SAFETEA''), to administer in certain areas of Indian country (as defined at 18 U.S.C. 1151) the State's environmental regulatory programs that were previously approved by the EPA for areas outside of Indian country. The State's request excluded certain areas of Indian country further described later. In addition, the State only sought approval to the extent that such approval is necessary for the State to administer a program in light of *Oklahoma Dept. of Environmental Quality* v. *EPA,* 740 F.3d 185 (D.C. Cir. 2014).[121]

On October 1, 2020, the EPA approved Oklahoma's SAFETEA request to administer all the State's EPA-approved environmental regulatory programs, including the Oklahoma SIP, in the requested areas of Indian country.[122] As requested by Oklahoma, the EPA's approval under SAFETEA does not include Indian country lands, including rights-of-way running through the same, that: (1) qualify as Indian allotments, the Indian titles to which have not been extinguished, under 18 U.S.C. 1151(c); (2) are held in trust by the United States on behalf of an individual Indian or Tribe; or (3) are owned in fee by a Tribe, if the Tribe (a) acquired that fee title to such land, or an area that included such land, in accordance with a treaty with the United States to which such Tribe was a party, and (b) never allotted the land to a member or citizen of the Tribe

[119] *https://www.epa.gov/system/files/documents/2022-03/fy-2022-2026-epa-strategic-plan.pdf.*

[120] Executive Order 13985 (January 20, 2021) (86 FR 7009 (January 25, 2021)): *https://www.govinfo.gov/content/pkg/FR-2021-01-25/pdf/2021-01753.pdf.*

[121] In *ODEQ* v. *EPA,* the D.C. Circuit held that under the CAA, a state has the authority to implement a SIP in non-reservation areas of Indian country in the state, where there has been no demonstration of tribal jurisdiction. Under the D.C. Circuit's decision, the CAA does not provide authority to states to implement SIPs in Indian reservations. *ODEQ* did not, however, substantively address the separate authority in Indian country provided specifically to Oklahoma under SAFETEA. That separate authority was not invoked until the State submitted its request under SAFETEA, and was not approved until the EPA's decision, described in this section, on October 1, 2020.

[122] Available in the docket for this rulemaking.

(collectively ''excluded Indian country lands'').

The EPA's approval under SAFETEA expressly provided that to the extent EPA's prior approvals of Oklahoma's environmental programs excluded Indian country, any such exclusions are superseded for the geographic areas of Indian country covered by the EPA's approval of Oklahoma's SAFETEA request.[123] The approval also provided that future revisions or amendments to Oklahoma's approved environmental regulatory programs would extend to the covered areas of Indian country (without any further need for additional requests under SAFETEA).

In a **Federal Register** document published on February 13, 2023 (88 FR 9336), the EPA disapproved the portion of an Oklahoma SIP submittal pertaining to the state's interstate transport obligations under CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS. Consistent with the D.C. Circuit's decision in *ODEQ* v. *EPA* and with the EPA's October 1, 2020 SAFETEA approval, the EPA has authority under CAA section 110(c) to promulgate a FIP as needed to address the disapproved aspects of Oklahoma's good neighbor SIP submittal.[124] In accordance with the previous discussion, the EPA's FIP authority in this circumstance extends to all Indian country in Oklahoma, other than the excluded Indian country lands, as described previously.[125] Because—per the State's request under SAFETEA—EPA's October 1, 2020 approval does not displace any SIP authority previously exercised by the State under the CAA as interpreted in *ODEQ* v. *EPA,* the EPA's FIP authority under CAA section 110(c) also applies to any Indian allotments or dependent Indian communities located outside of an Indian reservation over which there has been no demonstration of tribal authority. The EPA's FIP authority under CAA section 110(c) similarly applies to Indian allotments or dependent Indian communities located outside of an Indian reservation over which there has been no demonstration of tribal authority located in any other state within the geographic scope of this rule.

In light of the relevant legal authorities discussed above regarding the scope of the State of Oklahoma's regulatory jurisdiction under the CAA, the EPA has FIP authority under CAA section 110(c) with respect to all Indian country in Oklahoma other than excluded Indian country lands. To the extent any change occurs in the scope of Oklahoma's SIP authority in Indian country following finalization of this rule, and such change affects the exercise of FIP authority provided under section 110(c) of the Act,[126] then, to the extent any such areas would fall more appropriately within the CAA section 301(d) FIP areas as described in section III.C.2.a of this document, the EPA's necessary or appropriate finding as set forth above with respect to all other CAA section 301(d) FIP areas within the geographic scope of coverage of the rule would apply.

D. Severability

The EPA regards this action as a complete remedy, which will as expeditiously as practicable implement good neighbor obligations for the 2015 ozone NAAQS for the covered states, consistent with the requirements of the Act. *See North Carolina* v. *EPA,* 531 F.3d 896, 911–12 (D.C. Cir. 2008); *Wisconsin* v. *EPA,* 938 F.3d 303, 313–20 (D.C. Cir. 2019); *Maryland* v. *EPA,* 958 F.3d 1185, 1204 (D.C. Cir. 2020); *New York* v. *EPA,* 964 F.3d 1214, 1226 (D.C. Cir. 2020); *New York* v. *EPA,* 781 Fed. App'x 4, 7–8 (D.C. Cir. 2019) (all holding that the EPA must address good neighbor obligations as expeditiously as practicable and by no later than the next applicable attainment date). Yet should a court find any discrete aspect of this document to be invalid, the Agency believes that the remaining aspects of this rule can and should continue to be implemented to the extent possible. In particular, this action promulgates a FIP for each covered state (and, pursuant to CAA section 301(d), for each area of tribal jurisdiction within the geographic boundaries of those states). Should any jurisdiction-specific aspect of the final rule be found invalid, the EPA views this rule as severable along those state and/or tribal jurisdictional lines, such that the rule can continue to be implemented as to any remaining jurisdictions. This action promulgates discrete emissions control requirements for the power sector and for each of seven other industries. Should any industry-specific aspect of the final rule be found invalid, the EPA views this rule as severable as between the different industries and different types of emissions control requirements. This is not intended to be an exhaustive list of the ways in which the rule may be severable. In the event any part of it is found invalid, our intention is that the remaining portions should continue to be implemented consistent with any judicial ruling.

The EPA's conclusion that this rule is severable also reflects the important public health and environmental benefits of this rulemaking in eliminating significant contribution and to ensure to the greatest extent possible the ability of both upwind states and downwind states and other relevant stakeholders to be able to rely on this final rule in their planning. *Cf. Wisconsin,* 938 F.3d at 336–37 (''As a general rule, we do not vacate regulations when doing so would risk significant harm to the public health or the environment.''); *North Carolina* v. *EPA,* 550 F.3d 1176, 1178 (D.C. Cir. 2008) (noting the need to preserve public health benefits); *EME Homer City* v. *EPA,* 795 F.3d 118, 132 (D.C. Cir. 2015) (noting the need to avoid disruption to emissions trading market that had developed).

IV. Analyzing Downwind Air Quality Problems and Contributions From Upwind States

A. Selection of Analytic Years for Evaluating Ozone Transport Contributions to Downwind Air Quality Problems

In this section, the EPA describes its process for selecting analytic years for air quality modeling and analyses performed to identify nonattainment and maintenance receptors and identify upwind state linkages. For this final rule, the EPA evaluated air quality to identify receptors at Step 1 for two

[123] The EPA's prior approvals relating to Oklahoma's SIP frequently noted that the SIP was not approved to apply in areas of Indian country (consistent with the D.C. Circuit's decision in *ODEQ* v. *EPA*) located in the state. *See, e.g.,* 85 FR 20178, 20180 (April 10, 2020). Such prior expressed limitations are superseded by the EPA's approval of Oklahoma's SAFETEA request.

[124] The antecedent fact that the state had the authority and jurisdiction to implement requirements under the good neighbor provision, in the EPA's view, supplies the condition necessary for the Agency to exercise its FIP authority to the extent the EPA has disapproved the state's SIP submission with respect to those requirements. Under CAA section 110(c), the EPA ''stands in the shoes of the defaulting state, and all of the rights and duties that would otherwise fall to the state accrue instead to the EPA.'' *Central Ariz. Water Conservation Dist.* v. *EPA,* 990 F.2d 1531, 1541 (9th Cir. 1993).

[125] With respect to those areas of Indian country constituting ''excluded Indian country lands'' in the State of Oklahoma, as defined supra, the EPA applies the same necessary or appropriate finding as set forth above with respect to all other 301(d) FIP areas within the geographic scope of coverage of the rule.

[126] On December 22, 2021, the EPA proposed to withdraw and reconsider the October 1, 2020, SAFETEA approval. *See https://www.epa.gov/ok/proposed-withdrawal-and-reconsideration-and-supporting-information.* The EPA is engaging in further consultation with tribal governments and expects to have discussions with the State of Oklahoma as part of this reconsideration. The EPA also notes that the October 1, 2020, approval is the subject of a pending challenge in Federal court. *Pawnee Nation of Oklahoma* v. *Regan,* No. 20–9635 (10th Cir.).

analytic years: 2023 and 2026. The EPA evaluated interstate contributions to these receptors from individual upwind states at Step 2 for these two analytic years. In selecting these years, the EPA views 2023 and 2026 to constitute years by which key emissions reductions from EGUs and non-EGUS can be implemented ''as expeditiously as practicable.'' In addition, these years are the last full ozone seasons before the Moderate and Serious area attainment dates for the 2015 ozone NAAQS (ozone seasons run each year from May 1–September 30). To demonstrate attainment by these deadlines, downwind states would be required to rely on design values calculated using ozone data from 2021 through 2023 and 2024 through 2026, respectively. By focusing its analysis, and, potentially, achieving emissions reductions by, the last full ozone seasons before the attainment dates (*i.e.,* in 2023 or 2026), this final rule can assist the downwind areas with demonstrating attainment or receiving extensions of attainment dates under CAA section 181(a)(5). (The EPA explains in detail in sections V and VI of this document its determinations regarding which emissions reduction strategies can be implemented by 2023, and which emissions reduction strategies require additional time beyond that ozone season, or the 2026 ozone season.)

It would not be logical for the EPA to analyze any earlier year than 2023. The EPA continues to interpret the good neighbor provision as forward-looking, based on Congress's use of the future-tense ''will'' in CAA section 110(a)(2)(D)(i), an interpretation upheld in *Wisconsin,* 938 F.3d at 322. It would be ''anomalous,'' *id.,* for the EPA to impose good neighbor obligations in 2023 and future years based solely on finding that ''significant contribution'' had existed at some time in the past. *Id.*

Applying this framework in the proposal, the EPA recognized that the 2021 Marginal area attainment date had already passed. Further, based on the timing of the proposal, it was not possible to finalize this rulemaking before the 2022 ozone season had also passed. Thus, the EPA has selected 2023 as the first appropriate future analytic year for this final rule because it reflects implementation of good neighbor obligations as expeditiously as practicable and coincides with the August 3, 2024, Moderate area attainment date established for the 2015 ozone NAAQS.

The EPA conducted additional analysis for 2026 to ensure a complete Step 3 analysis for future ozone transport contributions to downwind areas. As noted above, 2023 and 2026 coincide with the last full ozone seasons before future attainment dates for the 2015 ozone NAAQS. In addition, 2026 coincides with the ozone season by which key additional emissions reductions from EGUs and non-EGUs become available. Thus, the EPA analyzed additional years beyond 2023 to determine whether any additional emissions reductions that are impossible to obtain by the 2024 attainment date could still be necessary to fully address significant contribution. In all cases, implementation of necessary emissions reductions is as expeditiously as practicable, with all possible emissions reductions implemented by the next applicable attainment date.

The timing framework and selection of analytic years set forth above comports with the D.C. Circuit's direction in *Wisconsin* that implementing good neighbor obligations beyond the dates established for attainment may be justified on a proper showing of impossibility or necessity. *See* 938 F.3d at 320.

Comment: A commenter claims that the EPA has not followed the holdings of *Wisconsin* v. *EPA,* 938 F.3d 303 (D.C. Cir. 2019), *North Carolina* v. *EPA,* 550 F.3d 1176 (D.C. Cir. 2008), and *Maryland* v. *EPA,* 958 F. 3d 1185 (D.C. Cir. 2020) in the selection of analytic years, in that commenter interprets those decisions as holding that the EPA must ''harmonize'' the exact timing of upwind emissions reductions with when downwind states implement their required reductions. Commenter also points to the EPA's proposed action on New York's Good Neighbor SIP submission specifically to argue that the EPA is treating upwind and downwind states dissimilarly. Commenter also cites CAA sections 172, 177, and 179 to argue the EPA did not properly align upwind and downwind obligations. Several commenters believe the EPA should defer implementing good neighbor requirements until downwind receptor areas have first implemented their own emissions control strategies.

Response: The EPA maintains that 2023 is an appropriate analytic year and comports with the relevant caselaw. Section VI.A further discusses the compliance schedule for emissions reductions under this rule. Commenter misreads the *North Carolina, Wisconsin,* and *Maryland* decisions as calling for good neighbor analysis and emissions controls to be aligned with the timing of the *implementation* of nonattainment controls by downwind states. However, the D.C. Circuit has held that the *statutory attainment dates* are the relevant downwind deadlines the EPA must align with in implementing the good neighbor provision. In *Wisconsin,* the court held, ''In sum, under our decision in *North Carolina,* the Good Neighbor Provision calls for elimination of upwind States' significant contributions *on par with the relevant downwind attainment deadlines.*'' *Wisconsin,* 938 F.3d. at 321 (emphasis added).

After that decision, the EPA interpreted *Wisconsin* as limited to the attainment dates for Moderate or higher classifications under CAA section 181 on the basis that Marginal nonattainment areas have reduced planning requirements and other considerations. *See, e.g.,* 85 FR 29882, 29888–89 (May 19, 2020) (proposed approval of South Dakota's 2015 ozone NAAQS good neighbor SIP). However, on May 19, 2020, the D.C. Circuit in *Maryland* v. *EPA,* 958 F.3d 1185 (D.C. Cir. 2020), applying the *Wisconsin* decision, rejected that argument and held that the EPA must assess air quality at the next downwind attainment date, including Marginal area attainment dates under CAA section 181, in evaluating the basis for the EPA's denial of a petition under CAA section 126(b). 958 F.3d at 1203–04. After *Maryland,* the EPA acknowledged that the Marginal attainment date is the first attainment date to consider in evaluating good neighbor obligations. *See, e.g.,* 85 FR 67653, 67654 (Oct. 26, 2020) (final approval of South Dakota's 2015 ozone NAAQS good neighbor SIP).

The D.C. Circuit again had occasion to revisit the Agency's interpretation of *North Carolina, Wisconsin,* and *Maryland,* in a challenge to the Revised CSAPR Update brought by the Midwest Ozone Group (MOG). The court declined to entertain similar arguments to those presented by commenters here and instead in a footnote explained that it had ''exhaustively summarized the regulatory framework governing EPA's conduct'' and that it ''[drew] on those decisions and incorporate them herein by reference,'' citing, among other cases, *Maryland,* 958 F.3d 1185, and *New York,* 781 F. App'x 4. *MOG* v. *EPA,* No. 21–1146 (D.C. Cir. March 3, 2023), Slip Op. at 3 n.1.

The relevance of CAA sections 172, 177, and 179 to the selection of the analytic year in this action is not clear. Commenter cites these provisions to conclude that the EPA did not appropriately consider downwind attainment deadlines and the timing of upwind good neighbor obligations. These provisions are found in subpart I, and while they may have continuing relevance or applicability to aspects of ozone nonattainment planning requirements, the nonattainment dates for the 2015 ozone NAAQS flow from subpart 2 of title I of the CAA, and specifically CAA section 181(a). Applying that statutory schedule to the designations for the 2015 ozone NAAQS, the EPA has promulgated the applicable attainment dates in its regulations at 40 CFR 51.1303. The effective date of the initial designations for the 2015 ozone NAAQS was August 3, 2018 (83 FR 25776, June 4, 2018, effective August 3, 2018).[127] Thus, the first deadline for attainment planning under the 2015 ozone NAAQS was the Marginal attainment date of August 3, 2021, and the second deadline for attainment planning is the Moderate attainment date of August 3, 2024. If a Marginal area fails to attain by the attainment date it is reclassified, or ''bumped up,'' to Moderate. Indeed, the EPA has just completed a rulemaking action reclassifying many areas of the country from Marginal to Moderate nonattainment, including all of the areas where downwind receptors have been identified in our 2023 modeling as well as many other areas of the country. 87 FR 60897, 60899 (Oct. 7, 2022).

Other than under the narrow circumstances of CAA section 181(a)(5) (discussed further in this section), the EPA is not permitted under the CAA to extend the attainment dates for areas under a given classification. That is, no matter when or if the EPA finalizes a determination that an area failed to attain by its attainment date and reclassifies that area, the attainment date remains fixed, based on the number of years from the area's initial designation. *See, e.g.,* CAA section 182(i) (authorizing the EPA to adjust any applicable deadlines for newly reclassified areas ''other than attainment dates''). As the D.C. Circuit has repeatedly made clear, the statutory attainment schedule of the downwind nonattainment areas under subpart 2 is rigorously enforced and is not subject to change based on policy considerations of the EPA or the states.

> [T]he attainment deadlines, the Supreme Court has said, are ''the heart'' of the Act. *Train* v. *Nat. Res. Def. Council,* 421 U.S. 60, 66, 95 S.Ct. 1470, 43 L.Ed.2d 731 (1975); *see Sierra Club* v. *EPA,* 294 F.3d 155, 161 (D.C. Cir. 2002) (''the attainment deadlines are central to the regulatory scheme'') (alteration and internal quotation marks omitted). The Act's central object is the ''attain[ment] [of] air quality of specified standards [within] a specified period of time.'' *Train,* 421 U.S. at 64–65, 95 S.Ct. 1470.

Wisconsin, 938 F.3d at 316. *See also Natural Resources Defense Council* v. *EPA,* 777 F.3d 456, 466–68 (D.C. Cir. 2014) (holding the EPA cannot adjust the section 181 attainment schedule to run from any other date than from the date of designation); *id.* at 468 (''EPA identifies no statutory provision giving it free-form discretion to set Subpart 2 compliance deadlines based on its own policy assessment concerning the number of ozone seasons within which a nonattainment area should be expected to achieve compliance.'') (citing and quoting *Whitman* v. *American Trucking Ass'ns,* 531 U.S. 457, 484, (2001) (''The principal distinction between Subpart 1 and Subpart 2 is that the latter eliminates regulatory discretion that the former allowed.''). Furthermore, as the court in *NRDC* noted, ''[T]he 'attainment deadlines . . . leave no room for claims of technological or economic infeasibility.' '' 777 F.3d at 488 (quoting *Sierra Club,* 294 F.3d at 161) (internal quotation marks and brackets omitted).

With the exception of the Uinta Basin, which is not an identified receptor in this action, no Marginal nonattainment area met the conditions of CAA section 181(a)(5) to obtain a one-year extension of the Moderate area attainment date. 87 FR 60899. Thus, all Marginal areas (other than Uinta) that failed to attain have been reclassified to Moderate. *Id.* (And the New York City Metropolitan nonattainment area was initially classified as Moderate (see following text for further details).) Even if the EPA had extended the attainment date for any of the downwind areas, it is not clear that it would necessarily follow that the EPA must correspondingly extend or delay the implementation of good neighbor obligations. While the *Wisconsin* court recognized extensions under CAA section 181(a)(5) as a possible source of timing flexibility in implementing the good neighbor provision, 938 F.3d at 320, the EPA and the states are still obligated to implement good neighbor reductions as expeditiously as practicable and are also obligated under the good neighbor provision to address ''interference with maintenance.'' Areas that have obtained an extension under CAA section 181(a)(5) or which are not designated as in nonattainment could still be identified as struggling to maintain the NAAQS, and the EPA is obligated under the good neighbor provision to eliminate upwind emissions interfering with the ability to maintain the NAAQS, as well. *North Carolina,* 531 F.3d at 908–11. Thus, while an extension under CAA section 181(a)(5) may be a source of flexibility for the EPA to consider in the timing of implementation of good neighbor obligations, as *Wisconsin* recognized, it is not the case that the EPA *must* delay or defer good neighbor obligations for that reason, and neither the D.C. Circuit nor any other court has so held.

Commenter is therefore incorrect to the extent that they argue the selection of 2023 as an analytic year for upwind obligations results in the misalignment of downwind and upwind state obligations. To the contrary, both downwind and upwind state obligations are driven by the statutory attainment date of August 3, 2024 for Moderate areas, and the last year that air quality data may impact whether nonattainment areas are found to have attained by the attainment date is 2023. That is why, in the recent final rulemaking determinations that certain Marginal areas failed to attain by the attainment date, bumping those areas up to Moderate, and giving them SIP submission deadlines, reasonably available control measures (RACM), and reasonably RACT implementation deadlines, the EPA set the attainment SIP submission deadlines for the bumped up Moderate areas to be January 1, 2023. See 87 FR 60897, 60900 (Oct. 7, 2022). The implementation deadline for RACM and RACT is also January 1, 2023. *Id.* This was in large part driven by the EPA's ozone implementation regulations, 40 CFR 51.1312(a)(3)(i), which previously established a RACT implementation deadline for initially classified Moderate as no later than January 1, 2023, and the modeling and attainment demonstration requirements in 40 CFR 51.1308(d), which require a state to provide for implementation of all control measures needed for attainment no later than the beginning of the attainment year ozone season (*i.e.,* 2023). Given this regulatory history, the EPA can hardly be accused of letting states with nonattainment areas for the 2015 ozone NAAQS avoid or delay their mandatory CAA obligations.

Commenter's proposal that the EPA align good neighbor obligations with the actual implementation of measures in downwind areas is untethered from the statute, as discussed above. It is also unworkable in practice. It would necessitate coordinating the activities of multiple states and EPA regional and headquarters offices to an impossible degree and effectively could preclude the implementation of good neighbor obligations altogether. Commenter does not explain how the EPA or upwind states should coordinate upwind emissions control obligations for states

[127] September 24, 2018, for the San Antonio area. 83 FR 35136 (July 25, 2018).

linked to multiple downwind receptors whose states may be implementing their requirements on different timetables. Less drastic mechanisms than subjecting people living in downwind receptor areas to continuing high levels of air pollution caused in part by upwind-state pollution are available if the actual implementation of mandatory CAA requirements in the downwind areas is delayed: CAA section 304(a)(2) provides for judicial recourse where there is an alleged failure by the Agency to perform a nondiscretionary duty; that recourse is for the Agency to be placed on a court-ordered deadline to address the relevant obligations. *See Oklahoma* v. *U.S. EPA,* 723 F.3d 1201, 1223–24 (10th Cir. 2013); *Montana Sulphur and Chemical Co.* v. *U.S. EPA,* 666 F.3d 1174, 1190–91 (9th Cir. 2012). Commenter focuses on the EPA's evaluation of New York's Good Neighbor SIP submission to argue the EPA is treating upwind and downwind states dissimilarly. The argument conflates New York's role as both a downwind and an upwind state. In evaluating the Good Neighbor SIP submission that New York submitted, the EPA identified as a basis for disapproval that none of the state emissions control programs New York cited included implementation timeframes to achieve the reductions, let alone ensure they were achieved by 2023. 87 FR 9484, 9494 (Feb. 22, 2022). The EPA conducted the same inquiry into other states' claims regarding their existing or proposed state laws or other emissions reductions claimed in their SIP submissions. *See, e.g.,* 87 FR 9472–73 (evaluating claims regarding emissions reductions anticipated under Maryland's state law); 87 FR 9854 (evaluating claims regarding emissions reductions anticipated under Illinois' state law). Consistent with its treatment of the other upwind states included in this action, the EPA in a separate action disapproved New York's good neighbor SIP submission for the 2015 ozone NAAQS because its arguments did not demonstrate that it had fully prohibited emissions significantly contributing to out of state nonattainment or maintenance problems.

Commenter attempts to contrast this evaluation with what it believes is the EPA's permissive attitude toward delays by downwind states, specifically claiming that ''certain nonattainment areas have delayed implementation of nonattainment controls until 2025 and beyond.'' This apparently references New York's simple cycle and regenerative combustion turbines (SCCT) controls, which commenter cited elsewhere in its comments. New York's SCCT controls were not included by New York in its good neighbor SIP submission, nor was the prior approval of the SCCT controls reexamined by the EPA or reopened for consideration by the Agency in this action. Although not part of this rulemaking, the EPA notes that the SCCT controls were approved by the EPA as a SIP strengthening measure and not to satisfy any specific planning requirements for the 2015 ozone NAAQS under CAA section 182. 86 FR 43956, 43958 (Aug. 11, 2021). The SCCT controls submitted to the EPA were already a state rule, and the only effect under the CAA of the EPA approving them into New York's SIP was to make them federally enforceable. 86 FR 43956, 43959 (Aug. 11, 2021). In other words, approval of the SCCT controls did not relieve New York of its nonattainment planning obligations for the 2015 ozone NAAQS.

The EPA notes that the New York-Northern New Jersey-Long Island, NY-NJ-CT nonattainment area was initially designated as Moderate nonattainment. 83 FR 25776 (June 4, 2018). Pursuant to this designation, New York was required to submit a RACT SIP submission and an attainment demonstration no later than 24 months and 36 months, respectively, after the effective date of the Moderate designation. CAA section 182; 40 CFR 51.1308(a), 51.1312(a)(2). New York submitted a RACT SIP for the 2015 ozone standards on January 29, 2021,[128] and the EPA is currently evaluating that submission. New York has not yet submitted its attainment demonstration, which was due August 3, 2021. Further, the New York-Northern New Jersey-Long Island, NY-NJ-CT nonattainment area remains subject to the Moderate nonattainment area date of August 3, 2024. If it fails to attain the 2015 ozone NAAQS by August 3, 2024, it will be reclassified to Serious nonattainment, resulting in additional requirements on the New York nonattainment area.

In any case, regardless of the status of New York's and the EPA's efforts in relation to the New York-Northern New Jersey-Long Island, NY-NJ-CT nonattainment area (which are outside the scope of this action), the EPA's evaluation of 2023 as the relevant analytic year in assessing New York's and other states' good neighbor obligations is consistent with the statutory framework and court decisions calling on the agency to align these obligations with the downwind areas' statutory attainment schedule. The EPA further responds to these comments in the *RTC* document in the docket.

The remainder of this section includes information on (1) the air quality modeling platform used in support of the final rule with a focus on the base year and future year base case emissions inventories, (2) the method for projecting design values in 2023 and 2026, and (3) the approach for calculating ozone contributions from upwind states. The Agency also provides the design values for nonattainment and maintenance receptors and the largest predicted downwind contributions in 2023 and 2026 from each state. The 2016 base period and 2023 and 2026 projected design values and contributions for all ozone monitoring sites are provided in the docket for this rule. The ''Air Quality Modeling Technical Support Document for the Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards Final Rulemaking'' (Mar. 2023), hereinafter referred to as the Air Quality Modeling Final Rule TSD, in the docket for this final rule contains more detailed information on the air quality modeling aspects of this rule.

B. Overview of Air Quality Modeling Platform

The EPA used version 3 of the 2016-based modeling platform (*i.e.,* 2016v3) for the air quality modeling for this final rule. This modeling platform includes 2016 base year emissions from anthropogenic and natural sources and anthropogenic emissions projections for 2023 and 2026. The emissions data contained in this platform represent an update to the 2016 version 2 inventories used for the proposal modeling.

The air quality modeling for this final rule was performed for a modeling region (*i.e.,* modeling domain) that covers the contiguous 48 states using a horizontal resolution of 12 x 12 km. The EPA used the CAMx version 7.10 for air quality modeling which is the same model that EPA used for the proposed rule air quality modeling.[129] Additional information on the 2016-based air quality modeling platform can be found in the Air Quality Modeling Final Rule TSD.

Comment: Commenters noted that the 2016 base year summer maximum daily average 8-hour (MDA8) ozone predictions from the proposal modeling were biased low compared to the corresponding measured concentrations in certain locations. In this regard, commenters said that model

[128] *https://edap.epa.gov/public/extensions/S4S_Public_Dashboard_2/S4S_Public_Dashboard_2.html.*

[129] Ramboll Environment and Health, January 2021, *https://www.camx.com.*

performance statistics for a number of monitoring sites, particularly those in portions of the West and in the area around Lake Michigan, were outside the range of published performance criteria for normalized mean bias (NMB) and normalized mean error (NME) of less than ±15 percent and less than 25 percent, respectively (Emory, et al., 2017).[130] The commenters said EPA must investigate the factors contributing to low bias and make necessary corrections to improve model performance in the final rule modeling. Some commenters said that EPA should include NO_X emissions from lightning strikes and assess the treatment of other background sources of ozone to improve model performance for the final rule. Additional information on the comments on model performance can be found in the *RTC* document for this final rule.

Response: In response to these comments EPA examined the temporal and spatial characteristics of model under prediction to investigate the possible causes of under prediction of MDA8 ozone concentrations in different regions of the U.S. in the proposal modeling. EPA's analysis indicates that the under prediction was most extensive during May and June with less bias during July and August in most regions of the U.S. For example, in the Upper Midwest region model under prediction was larger in May and June compared to July through September. Specifically, in the proposal modeling, the normalized mean bias for days with measured concentrations ≥60 ppb improved from a 21.4 percent under prediction for May and June to a 12.6 percent under prediction in the period July through September. As described in the Air Quality Modeling Final Rule TSD, the seasonal pattern in bias in the Upper Midwest region improves somewhat gradually with time from the middle of May to the latter part of June. In view of the seasonal pattern in bias in the Upper Midwest and in other regions of the U.S., EPA focused its investigation of model performance on model inputs that, by their nature, have the largest temporal variation within the ozone season. These inputs include emissions from biogenic sources and lightning NO_X, and contributions from transport of international anthropogenic emissions and natural sources into the U.S. Both biogenic and lightning NO_X emissions in the U.S. dramatically increase from spring to summer.[131] [132] In contrast, ozone transported into the U.S. from international anthropogenic and natural sources peaks during the period March through June, with lower contributions during July through September.[133] [134] To investigate the impacts of these sources, EPA conducted sensitivity model runs which focused on the effects on model performance of adding NO_X emissions from lightning strikes, updating biogenic emissions, and using an alternative approach for quantifying transport of ozone and precursor pollutants into the U.S. from international anthropogenic and natural sources. The development of lightning NO_X emissions and the updates to biogenic emissions, are described in section IV.C of this document. In the proposal modeling the amount of transport from international anthropogenic and natural sources was based on a simulation of the hemispheric version of the Community Multi-scale Air Quality Model (H–CMAQ) for 2016.[135] The outputs from this hemispheric modeling were then used to provide boundary conditions for national scale air quality modeling at proposal.[136] Overall, H–CMAQ tends to under-predict daytime ozone concentrations at rural and remote monitoring sites across the U.S. during the spring of 2016 whereas the predictions from the GEOS-Chem global model [137] were generally less biased.[138] During the summer of 2016 both models showed varying degrees of over prediction with GEOS-Chem showing somewhat greater over-prediction, compared to H–CMAQ. In view of those results, EPA examined the impacts of using GEOS-Chem as an alternative to H–CMAQ for providing boundary conditions for the final rule modeling.

For the lightning NO_X, biogenics, and GEOS-Chem sensitivity runs, EPA reran the proposal modeling using each of these inputs, individually. Results from these sensitivity runs indicate that each of the three updates provides an improvement in model performance. However, by far the greatest improvement in model performance is attributable to the use of GEOS-Chem. In view of these results EPA has included lightning NO_X emissions, updated biogenic emissions, and international transport from GEOS-Chem in the final rule air quality modeling. Details on the results of the individual sensitivity runs can be found in the Air Quality Modeling Final Rule TSD. For the air quality modeling supporting this final action, model performance based on days in 2016 with measured MDA8 ozone ≥60 ppb is considerably improved (*i.e.,* less bias and error) compared to the proposal modeling in nearly all regions of the U.S. For example, in the Upper Midwest, which includes monitoring sites along Lake Michigan, the normalized mean bias improved from a 19 percent under prediction to a 6.9 percent under prediction and in the Southwest region, which includes monitoring sites in Denver and Salt Lake City, normalized mean bias improved from a 13.6 percent under prediction to a 4.8 percent under prediction.[139] In all regions, the

[130] Christopher Emery, Zhen Liu, Armistead G. Russell, M. Talat Odman, Greg Yarwood & Naresh Kumar (2017) Recommendations on statistics and benchmarks to assess photochemical model performance, Journal of the Air & Waste Management Association, 67:5, 582–598, DOI: 10.1080/10962247.1265027.

[131] Guenther, A.B., 1997. Seasonal and spatial variations in natural volatile organic compound emissions. Ecol. Appl. 7, 34–45. *https://doi.org/10.1890/1051-0761(1997)007[0034:SASVIN]2.0.CO;2.* Guenther, A., Hewitt, C.N., Erickson, D., Fall, R.

[132] Kang D, Mathur R, Pouliot GA, Gilliam RC, Wong DC. Significant ground-level ozone attributed to lightning-induced nitrogen oxides during summertime over the Mountain West States. NPJ Clim Atmos Sci. 2020 Jan 30;3:6. doi: 10.1038/s41612–020–0108–2. PMID: 32181370; PMCID: PMC7075249.

[133] Jaffe DA, Cooper OR, Fiore AM, Henderson BH, Tonnesen GS, Russell AG, Henze DK, Langford AO, Lin M, Moore T. Scientific assessment of background ozone over the U.S.: Implications for air quality management. Elementa (Wash DC). 2018;6(1):56. doi: 10.1525/elementa.309. PMID: 30364819; PMCID: PMC6198683.

[134] Henderson, B.H., P. Dolwick, C. Jang, A., Eyth, J. Vukovich, R. Mathur, C. Hogrefe, N. Possiel, G. Pouliot, B. Timin, K.W. Appel, 2019. Global Sources of North American Ozone. Presented at the 18th Annual Conference of the UNC Institute for the Environment Community Modeling and Analysis System (CMAS) Center, October 21–23, 2019.

[135] Mathur, R., Gilliam, R., Bullock, O.R., Roselle, S., Pleim, J., Wong, D., Binkowski, F., and 1 Streets, D.: Extending the applicability of the community multiscale air quality model to 2 hemispheric scales: motivation, challenges, and progress. In: Steyn DG, Trini S (eds) Air 3 pollution modeling and its applications, XXI. Springer, Dordrecht, pp 175–179, 2012.

[136] Boundary conditions are the concentrations of pollutants along the north, east, south, and west boundaries of the air quality modeling domain. Boundary conditions vary in space and time and are typically obtained from predictions of global or hemispheric models. Information on how boundary conditions were developed for the final rule modeling can be found in the Air Quality Modeling Final Rule TSD.

[137] I. Bey, D.J. Jacob, R.M. Yantosca, J.A. Logan, B.D. Field, A.M. Fiore, Q. Li, H.Y. Liu, L.J. Mickley, M.G. Schultz. Global modeling of tropospheric chemistry with assimilated meteorology: model description and evaluation. J. Geophys. Res. Atmos., 106 (2001), pp. 23073–23095, 10.1029/2001jd000807.

[138] Henderson, B.H., P. Dolwick, C. Jang, A., Eyth, J. Vukovich, R. Mathur, C. Hogrefe, G., N. Possiel, B. Timin, K.W. Appel, 2022. Meteorological and Emission Sensitivity of Hemispheric Ozone and $PM_{2.5}$. Presented at the 21st Annual Conference of the UNC Institute for the Environment Community Modeling and Analysis System (CMAS) Center, October 17–19, 2022.

[139] A comparison of model performance from the proposal modeling to the final modeling for

Continued

normalized mean bias and normalized mean error statistics for high ozone days based on the final rule modeling are within the range of performance criteria benchmarks (*i.e.,* < ±15 percent for normalized mean bias and <25 percent for normalized mean error).[140] Additional information on model performance is provided in the Air Quality Modeling Final Rule TSD. In summary, EPA included emissions of lightning NO_X, as requested by commenters, and investigated and addressed concerns about model performance for the final rule modeling.

C. Emissions Inventories

The EPA developed emissions inventories to support air quality modeling for this final rule, including emissions estimates for EGUs, non-EGU point sources (*i.e.,* stationary point sources), stationary nonpoint sources, onroad mobile sources, nonroad mobile sources, other mobile sources, wildfires, prescribed fires, and biogenic emissions that are not the direct result of human activities. The EPA's air quality modeling relies on this comprehensive set of emissions inventories because emissions from multiple source categories are needed to model ambient air quality and to facilitate comparison of model outputs with ambient measurements.

Prior to air quality modeling, the emissions inventories were processed into a format that is appropriate for the air quality model to use. To prepare the emissions inventories for air quality modeling, the EPA processed the emissions inventories using the Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System version 4.9 to produce the gridded, hourly, speciated, model-ready emissions for input to the air quality model. Additional information on the development of the emissions inventories and on data sets used during the emissions modeling process are provided in the document titled, ''Technical Support Document (TSD): Preparation of Emissions Inventories for the 2016v3 North American Emissions Modeling Platform'' (Jan. 2023), hereafter known as the 2016v3 Emissions Modeling TSD. This TSD is available in the docket for this rule.[141]

1. Foundation Emissions Inventory Data Sets

The 2016v3 emissions platform is comprised of data from various sources including data developed using models, methods, and source datasets that became available in calendar years 2020 through 2022, in addition to data retained from the Inventory Collaborative 2016 version 1 (2016v1) Emissions Modeling Platform, released in October 2019. The 2016v1 platform was developed through a national collaborative effort between the EPA and state and local agencies along with MJOs. The 2016v2 platform used to support the proposed action included updated data from the 2017 NEI along with updates to models and methods as compared to 2016v1. The 2016v3 platform includes updates to the 2016v2 platform implemented in response to comments along with other updates to the 2016v2 platform such as corrections and the incorporation of updated data sources that became available prior to the 2016v3 inventories being developed. Several commenters noted that the 2016v2 platform did not include NO_X emissions that resulted from lightning strikes. To address this, lightning NO_X emissions were computed and included in the 2016v3 platform.

For this final rule, the EPA developed emissions inventories for the base year of 2016 and the projected years of 2023 and 2026. The 2023 and 2026 inventories represent changes in activity data and of predicted emissions reductions from on-the-books actions, planned emissions control installations, and promulgated Federal measures that affect anthropogenic emissions.[142] The 2016 emissions inventories for the U.S. primarily include data derived from the 2017 National Emissions Inventory (2017 NEI)[143] and data specific to the year of 2016. The following sections provide an overview of the construct of the 2016v3 emissions and projections. The fire emissions were unchanged between the 2016v2 and 2016v3 emissions platforms. For the 2016v3 platform, the biogenic emissions were updated to use the latest available versions of the Biogenic Emissions Inventory System and associated land use data to help address comments related to a degradation in model performance in the 2016v2 platform as compared to the 2016v1 platform. Details on the construction of the inventories are available in the 2016v3 Emissions Modeling TSD. Details on how the EPA responded to comments related to emissions inventories are available in the *RTC* document for this rule.

2. Development of Emissions Inventories for EGUs

a. EGU Emissions Inventories Supporting This Final Rule

Development of emissions inventories for annual NO_X and SO_2 emissions for EGUs in the 2016 base year inventory are based primarily on data from continuous emissions monitoring systems (CEMS) and other monitoring systems allowed for use by qualifying units under 40 CFR part 75, with other EGU pollutants estimated using emissions factors and annual heat input data reported to the EPA. For EGUs not reporting under Part 75, the EPA used data submitted to the NEI by the state, local, and tribal agencies. The Air Emissions Reporting Rule (80 FR 8787; February 19, 2015), requires that Type A point sources large enough to meet or exceed specific thresholds for emissions be reported to the EPA every year, while the smaller Type B point sources must only be reported to EPA every 3 years. Emissions data for EGUs that did not have data submitted to the NEI specific to the year 2016 were filled in with data from the 2017 NEI. For more information on the details of how the 2016 EGU emissions were developed and prepared for air quality modeling, see the 2016v3 Emissions Modeling TSD.

The EPA projected 2023 and 2026 baseline EGU emissions using the version 6—Updated Summer 2021 Reference Case of the Integrated Planning Model (IPM). IPM, developed by ICF Consulting, is a state-of-the-art, peer-reviewed, multi-regional, dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. It provides forecasts of least cost capacity expansion, electricity dispatch, and emissions control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. The EPA has used IPM for over two decades, including all prior implemented CSAPR rulemakings, to better understand power sector behavior under future business-

individual monitoring sites can be found in the docket for this final rule.

[140] Christopher Emery, Zhen Liu, Armistead G. Russell, M. Talat Odman, Greg Yarwood & Naresh Kumar (2017) Recommendations on statistics and benchmarks to assess photochemical model performance, Journal of the Air & Waste Management Association, 67:5, 582–598, DOI: 10.1080/10962247.1265027.

[141] See 2016v3 Emissions Modeling TSD, also available at *https://www.epa.gov/air-emissions-modeling/2016v3-platform*.

[142] Biogenic emissions and emissions from wildfires and prescribed fires were held constant between 2016 and the future years because (1) these emissions are tied to the 2016 meteorological conditions and (2) the focus of this rule is on the contribution from anthropogenic emissions to projected ozone nonattainment and maintenance.

[143] *https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-technical-support-document-tsd*.

as-usual conditions and to evaluate the economic and emissions impacts of prospective environmental policies. The model is designed to reflect electricity markets as accurately as possible. The EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM. The model documentation provides additional information on the assumptions discussed here as well as all other model assumptions and inputs.[144] The EPA relied on the same model platform at final as it did at proposal, but made substantial updates to reflect public comments on near-term fossil fuel market price volatility and updated fleet information reflecting Summer 2022 U.S. Energy Information Agency (EIA) 860 data, unit-level comments, and additional updates to the National Electric Energy Data System (NEEDS) inventory.

The IPM version 6—Updated Summer 2021 Reference Case incorporated recent updates through the Summer of 2022 to account for updated Federal and state environmental regulations (including Renewable Portfolio Standards (RPS), Clean Energy Standards (CES) and other state mandates), fleet changes (committed EGU retirements and new builds), electricity demand, technology cost and performance assumptions from recent data (for renewables adopting from National Renewable Energy Lab (NREL's) Annual Technology Baseline 2020 and for fossil sources from EIA's Annual Energy Outlook (AEO) 2020. Natural gas and coal price projections reflect data developed in Fall 2020 but updated in summer of 2022 to capture near-term price volatility and current market conditions. The inventory of EGUs provided as an input to the model was the NEEDS fall 2022 version and is available on EPA's website.[145] This version of NEEDS reflects announced retirements and under-construction new builds known as of early summer 2022. This projected base case accounts for the effects of the finalized Mercury and Air Toxics Standards rule, CSAPR, the CSAPR Update, the Revised CSAPR Update, NSR enforcement settlements, the final ELG Rule, CCR Rule, and other on-the-books Federal and state rules (including renewable energy tax credit extensions from the Consolidated Appropriations Act of 2021) through early 2021 impacting SO_2, NO_X, directly emitted particulate matter, CO_2, and power plant operations. It also includes final actions the EPA has taken to implement the Regional Haze Rule and best available retrofit technology (BART) requirements. Documentation of IPM version 6 and NEEDS, along with updates, is in Docket ID No. EPA–HQ–OAR–2021–0668 and available online at *https://www.epa.gov/airmarkets/power-sector-modeling*. IPM has projected output years for 2023 and 2025. IPM year 2025 outputs were adjusted for known retirements to be reflective of year 2026, and IPM year 2030 outputs were used for the year 2032 as is specified by the mapping of IPM output years to specific years.

Additional 2023 through 2026 EGU emissions baseline levels were developed through engineering analytics as an alternative approach that did not involve IPM. The EPA developed this inventory for use in Step 3 of this final rule, where it determines emissions reduction potential and corresponding state-level emissions budgets. IPM includes optimization and perfect foresight in solving for least cost dispatch. Given that this final rule will likely become effective immediately prior to the start of the 2023 ozone season, the EPA adopted a similar approach to the CSAPR Update and the Revised CSAPR Update where it utilized historical data and an engineering analytics approach in Step 3 to avoid overstating optimization and dispatch decisions in state-emissions budget quantification that may not be possible in a short time frame. The EPA does this by starting with unit-level reported data and only making adjustments to reflect known baseline changes such as planned retirements and new builds (for the base case scenarios) and also identified mitigation strategies for determining state emissions budgets. In both the CSAPR Update and in this rule at Step 3, the EPA complemented that projected IPM EGU outlook with an historical (*e.g.,* engineering analytics) perspective based on historical data that only factors in known changes to the fleet. This 2023 engineering analytics data set is described in more detail in the Ozone Transport Policy Analysis Final Rule TSD and corresponding Appendix A: State Emissions Budgets Calculations and Underlying Data. The Engineering Analysis used in Step 3 is also discussed further in section VII.B of this document.

Both IPM and the Engineering Analytics tools are valuable for estimating future EGU emissions and examining the cone of uncertainty around any future sector-level inventory estimate. A key difference between the two tools is that IPM reflects both announced and projected changes in fleet operation, whereas the Engineering Analytics tool only reflects announced changes. By not including projected regional changes that are anticipated in response to market forces and fleet trends, the Engineering Analysis deliberately creates future estimates of the power sector where state estimates are limited to known changes. Throughout all of the CSAPR rules to date, and prior interstate transport actions, the EPA has used IPM at Steps 1 and 2 as it is best suited for projecting emissions in an airshed, at projecting emissions for time horizons more than a few years out (for which changes would not yet be announced and thus projecting changes is critical), and for scenarios where the assumed change in emissions is not being codified into a state emissions reduction requirement. Using IPM at Steps 1 and 2 helps the EPA avoid overstating the current analytic year receptor values (Step 1) and future year linkages (Step 2) by reflecting reductions anticipated to occur within the airshed in the relevant timeframe.

Engineering analytics has been a useful tool for Step 3 state-level emissions reduction estimates in CSAPR rulemaking, because at that step the EPA is dealing with more geographic granularity (state-level as opposed to regional air shed), more near-term (as opposed to medium-term) assessments, and scenarios where reduction estimates are codified into regulatory requirements. Using the Engineering Analytics tool at this step ensures that the EPA is not codifying into the base case, and consequently into state emissions budgets, changes in the power sector that are merely modeled to occur rather than announced by real-world actors.

Finally, both in the Revised CSAPR Update and in this rule, the EPA was able to use the Air Quality Assessment Tool to determine that regardless of which EGU inventory is used, the 2023 geography of the program is not impacted. In other words, regardless of whether a stakeholder takes a more comprehensive view of the EGU future (IPM) or one limited to current data and known changes (Engineering Analysis), the states that are linked to receptors at Steps 1 and 2 would be the same. This finding is consistent with the observation that EGUs are now less than

[144] Detailed information and documentation of EPA's Base Case, including all the underlying assumptions, data sources, and architecture parameters can be found on EPA's website at: *https://www.epa.gov/airmarkets/epas-power-sector-modeling-platform-v6-using-ipm-summer-2021-reference-case.*

[145] Available at *https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6.*

10 percent of the total ozone-season NO_X inventory and the degree of near-term difference between the IPM and Engineering Analytic regional projections is relatively small on the regional level. The EPA continues to believe that IPM is best suited for Step 1 and Step 2, and engineering analytics is best suited for Step 3 efforts in this rulemaking. The Ozone Transport Policy Analysis Final Rule TSD contains data on 2023 and 2026 AQ impacts of each dataset.

Comment: Some commenters express concern that using IPM for Step 1 and Step 2 captures generation shifting across state lines, which exceeds the EPA's authority. Moreover, the commenters suggest that the resulting proposed baseline EGU inventory may understate emissions levels as it projects economic retirements that are not yet announced or firm. Other commenters more generally allege that the EPA is using different modeling tools at different steps in its analysis, and this introduces confusion or uncertainty into the basis for the EPA's regulatory conclusions.

Response: The EPA believes the first aspect of this comment, in regards to its focus on generation shifting, is misguided in several ways. For Step 1 and Step 2, the EPA models no incremental generation shifting attributable to the implementation of an emissions control policy at Step 3. Rather, any generation patterns are merely a reflection of the model's projection of how regional load requirements will be met with the generation sources serving that region in the baseline. The EPA is not modeling any additional generation shifting, but merely capturing the expected generation dispatch under anticipated baseline market conditions. Electricity generated in one state regularly is transmitted across state boundaries and is used to serve load in other states; IPM is not incentivizing or requiring any additional generation transfer across state lines in this scenario but is merely projecting the pattern of this behavior in the future. Moreover, as noted previously, the EPA affirms its geographic findings at Step 2 (states contributing over 1 percent of the NAAQS to a downwind receptor) using historical data (engineering analysis) in a sensitivity analysis. These historical data reflect the actual generation patterns observed to meet regional load. Therefore, any suggestion by the commenter that the EPA's projected view of baseline grid dispatch is unreasonable, is mooted by the fact that the use of historical reported generation patterns produces the same result.

Additionally, at the time of the proposal's analysis, the 2023 ozone season was still nearly two years away. Therefore, it was appropriate for EPA's modeling to project economic retirements as those retirements—which are regularly occurring—are often not firm or announced two years in advance. However, for this final rule, the 2023 analytic year was close enough to the period in which EPA was conducting its analysis that such retirements would likely be announced. Therefore, the EPA was able to incorporate those announced and firm retirements to occur in the 2023 year. Further, in recognition of this very near timeframe, we deactivated IPM's ability to project additional economic retirements for the 2023 year (reflecting the notion that any retirements occurring by 2023 would be known at this point). This adjustment further accommodates the commenters' concern that the baseline overstates generation shifting (driven by retirements) in the near term, and consequently understates emissions levels. Finally, with respect to comments that the EPA is using different modeling tools at different steps in the framework, we previously explained why these techniques are appropriate for the purposes at each step of the analysis, and they are not incompatible nor do they produce results so different as to call into question their reliability or the bases for our regulatory determinations (EPA notes that the nationwide projected ozone season total NO_X emissions vary by less than 1 percent in the 2023 analytic year). Nonetheless, we also observe that the effect of using engineering analytics to inform analysis at Steps 1 and 2 would tend to produce higher assumed emissions from EGUs in the baseline than IPM would project in 2026 and beyond and therefore only strengthen and further affirm the Step 1 and Step 2 geographic findings. EPA's use of different tools to project EGU scenarios is not inconsistent, but rather it is carefully explained as a deliberate measure taken to preserve—not introduce—consistency across each of the Steps in the 4-step framework. By using IPM at Step 1 and 2, EPA is selecting the more conservative approach for identifying the degree of nonattainment and geography of states contributing above 1 percent. By using Engineering Analytics at Step 3, EPA is selecting the more conservative value to codify into state-level budgets.

b. Impact of the Inflation Reduction Act on EGU Emissions

The EGU modeling used to construct the EGU emissions inventories used to inform the modeling projections for 2023 and 2026 was conducted prior to the passage of the Inflation Reduction Act (IRA), Public Law 117–169. The EPA did not have time to incorporate updated EGU projections reflecting the passage of the IRA into the primary air quality modeling for this final rule. However, the EPA was able to perform a sensitivity analysis reflecting the IRA in its EGU NO_X emissions inventories. The results from this scenario were run through AQAT and demonstrated that the status of states identified as linked at the 1 percent of NAAQS contribution threshold (based on the modeling and air quality analysis described in this section) would not change regardless of which inventory (with or without IRA) is used. This sensitivity analysis is presented in the Regulatory Impact Analysis accompanying this rule, and that discussion provides additional detail on the emissions consequences of including the IRA in a baseline EGU inventory. The air quality impact of including the IRA in EPA's emissions inventories and in its Step 3 scenarios is discussed in Appendix K of the Ozone Transport Policy Analysis Final Rule TSD.

The results of this analysis are not surprising and accord with what is generally understood to be the overall effect of the IRA over the short to long term. While the IRA is anticipated to have a potentially dramatic effect on reducing both GHG and conventional pollutant emissions from the power sector, it is likely to have a more substantial impact later in the forecast period (*i.e.,* beyond the attainment deadlines by which the emissions reductions under this final rule must occur). This timing reflects a realistic assessment of utilities', regulators', and transmission authorities' planning requirements associated with the addition of substantial new renewable and storage capacity to the grid, as well as the time needed to integrate that capacity and retire existing capacity. Additionally, the IRA incentives span a longer time period (for example, certain tax incentives for clean energy sources are available until the later of 2032 or the year in which power sector emissions are 75 percent below 2022 levels) and therefore there is no IRA-related deadline to build cleaner generation by 2026. Recent analysis by the Congressional Budget Office supports the finding that the majority of power sector EGU emissions reductions expected from the IRA occur well after the 2023 and 2026 analytic years relevant to the attainment dates and this rulemaking.[146] While the report focuses on CO_2 rather than NO_X, the drivers of the emissions reductions (primarily increased zero-emitting generation) would generally have a downward impact on both pollutants.

We note that important uncertainties remain at this time in the implementation of the IRA that further counsel against over-assuming short-term emissions reductions for purposes of this rule. The legislation provides economic incentives for shifting to cleaner forms of power generation but does not mandate emissions reductions through an enforceable regulatory program. The strength of those incentives will vary to some extent depending on other key market factors (such as the cost of natural gas or renewable energy technologies). Further, some incentives, such as tax credits for carbon capture and storage, could lead EGUs to remain in operation longer, which could in turn result in greater NO_X emissions, if those emissions are not also well controlled.

Nonetheless, while we find that the passage of the IRA does not affect the geography of the rule in terms of which states we identify as linked, the Agency is confident that the incentives toward clean technology provided in the IRA will, in the longer run beyond the 2015 ozone NAAQS attainment deadlines, facilitate ongoing EGU compliance with the emissions reduction requirements of this rule and will reduce costs borne by EGUs and their customers as the U.S. power sector transitions. As discussed in greater detail in section VI.B of this document, we have made several adjustments in the final rule to provide greater flexibility to EGU owners and operators to integrate this rule's requirements with and facilitate the accelerating transition to an overall cleaner electricity-generating sector, which the IRA represents. Despite the uncertainties inherent in the implementation of the IRA at this time, the EPA also has performed a sensitivity analysis on the final rule to confirm that our finding of no overcontrol is robust to a future with the IRA in effect.

3. Development of Emissions Inventories for Stationary Industrial Point Sources

Non-EGU point source emissions are mostly consistent with those in the proposal modeling except where they were updated in response to comments. Several commenters mentioned that point source emissions carried forward from 2014 NEI were not the best estimates of 2017 emissions. Thus, emissions sources in 2016v2 that had been projected from the 2014 NEI in the proposal were replaced with emissions based on the 2017 NEI. Point source emissions submitted to the 2016 NEI or to the 2016v1 platform development process specifically for the year 2016 were retained in 2016v3. Other 2016 non-EGU updates in 2016v3 include a few sources being moved to the EGU inventory, the addition of some control efficiency information for the year 2016, the replacement of most emissions projected from 2014 NEI with data from 2017 NEI, and the inclusion of point source data for solvent processes that had not been included in the 2016v2 non-EGU inventory.

The 2023 and 2026 non-EGU point source emissions were grown from 2016 to those years using factors based on the AEO 2022 and reflect emissions reductions due to known national and local rules, control programs, plant closures, consent decrees, and settlements that could be computed as reductions to specific units by July 2022.

Aircraft emissions and ground support equipment at airports are represented as point sources and are based on adjustments to emissions in the January 2021 version of the 2017 NEI. The EPA developed and applied factors to adjust the 2017 airport emissions to 2016, 2023 and 2026 based on activity growth projected by the Federal Aviation Administration Terminal Area Forecast 2021 [147] data, the latest available version at the time the factors were developed. By basing the factors on the latest available Terminal Area Forecast that was released following the most significant pandemic impacts on the aviation sector, the reduction and rebound impacts of the pandemic on aircraft and ground support equipment were reflected in the 2023 and 2026 airport emissions.

Emissions at rail yards were represented as point sources. The 2016 rail yard emissions are largely consistent with the 2017 NEI rail yard emissions. The 2016 and 2023 rail yard emissions were developed through the 2016v1 Inventory Collaborative process, with the 2026 emissions interpolated between the 2023 and 2028 emissions from 2016v1 rail yard emissions were interpolated from the 2016 and 2023 emissions. Class I rail yard emissions were projected based on the AEO freight rail energy use growth rate projections for 2023, and 2026 with the fleet mix assumed to be constant throughout the period.

The EPA made multiple updates to point source oil and gas emissions in response to comments. For the final rule, the point source oil and gas emissions for 2016 were based on the 2016v2 point inventory except that most 2014 NEI-based emissions were replaced with 2017 NEI emissions. Additionally, in response to comments, state-provided emissions equivalent to those in the 2016v1 platform were used for Colorado, and some New Mexico emissions were replaced with data backcast from 2020 to 2016. To develop inventories for 2023 and 2026 for the final rule, the year 2016 oil and gas point source inventories were first projected to 2021 values based on actual historical production data, then those 2021 emissions were projected to 2023 and 2026 using regional projection factors based on AEO 2022 projections. This was an update from the proposal approach that used actual data only through the year 2019, because 2021 data were not yet available. NO_X and VOC reductions resulting from co-benefits of NSPS for Stationary Reciprocating Internal Combustion Engines (RICE) are reflected, along with Natural Gas Turbine and Process Heater NSPS NO_X controls and Oil and Gas NSPS VOC controls. In some cases, year 2019 point source inventory data were used instead of the projected future year emissions except for the Western Regional Air Partnership (WRAP) states of Colorado, New Mexico, Montana, Wyoming, Utah, North Dakota, and South Dakota. The WRAP future year inventory [148] was used in these WRAP states in all future years except in New Mexico where the WRAP base year emissions were projected using the EIA historical and AEO forecasted production data. Estimated impacts from the New Mexico Administrative code 20.2.50 [149] were also included.

4. Development of Emissions Inventories for Onroad Mobile Sources

Onroad mobile sources include exhaust, evaporative, and brake and tire wear emissions from vehicles that drive on roads, parked vehicles, and vehicle refueling. Emissions from vehicles using regular gasoline, high ethanol gasoline, diesel fuel, and electric vehicles were represented, along with buses that used compressed natural gas. The EPA

[146] "Emissions of Carbon Dioxide In the Electric Power Sector," Congressional Budget Office. December 2022. Available at *https://www.cbo.gov/publication/58860.*

[147] *https://www.faa.gov/data_research/aviation/taf/.*

[148] *http://www.wrapair2.org/pdf/WRAP_OGWG_2028_OTB_RevFinalReport_05March2020.pdf.*

[149] *https://www.srca.nm.gov/parts/title20/20.002.0050.html.*

developed the onroad mobile source emissions for states other than California using the EPA's Motor Vehicle Emissions Simulator (MOVES). MOVES3 was released in November 2020 and has been followed by some minor releases that improved the usage of the model but that do not have substantive impacts on the emissions estimates. For the proposal, MOVES3 was run using inputs provided by state and local agencies through the 2017 NEI where available, in combination with nationally available data sets to develop a complete inventory. Onroad emissions were developed based on emissions factors output from MOVES3 runs for the year 2016, coupled with activity data (*e.g.,* vehicle miles traveled and vehicle populations) representing the year 2016. The 2016 activity data were provided by some state and local agencies through the 2016v1 process, and the remaining activity data were derived from those used to develop the 2017 NEI. The onroad emissions were computed within SMOKE by multiplying emissions factors developed using MOVES with the appropriate activity data. Prior to computing the final rule emissions, updates to some onroad inputs were made in response to comments and to implement corrections. Onroad mobile source emissions for California were consistent with the updated emissions data provided by the state for the final rule.

The 2023 and 2026 onroad emissions reflect projected changes to fuel properties and usage, along with the impact of the rules included in MOVES3 for each of those years. MOVES emissions factors for the years 2023 and 2026 were used. A comprehensive list of control programs included for onroad mobile sources is available in the 2016v3 Emissions Modeling TSD. Year 2023 and 2026 activity data for onroad mobile sources were provided by some state and local agencies, and otherwise were projected to 2023 and 2026 by first projecting the 2016 activity to year 2019 based on county level vehicle miles traveled (VMT) from the Federal Highway Administration. Because VMT for onroad mobile sources were substantially impacted by the pandemic and took about two years to rebound to pre-pandemic levels, in the 2016v3 platform no growth in VMT was implemented from 2019 to. The estimated 2021 VMT were then grown from 2021 to 2023 and 2026 using AEO 2022-based factors. Recent updates to inspection and maintenance programs in North Carolina and Tennessee were reflected in the MOVES inputs for the final rule modeling. The 2023 and 2026 onroad mobile emissions were computed within SMOKE by multiplying the respective emissions factors developed using MOVES with the year-specific activity data. Prior to computing the final rule emissions for 2023, the EPA made updates to some onroad inputs in response to comments and to implement corrections.

5. Development of Emissions Inventories for Commercial Marine Vessels

The commercial marine vessel (CMV) emissions in the 2016 base case emissions inventory for this rule were based on those in the 2017 NEI. Factors were applied to adjust the 2017 NEI emissions backward to represent emissions for the year 2016. The CMV emissions reflect reductions associated with the Emissions Control Area proposal to the International Maritime Organization control strategy (EPA–420–F–10–041, August 2010); reductions of NO_X, VOC, and CO emissions for new category 3 (C3) engines that went into effect in 2011; and fuel sulfur limits that went into effect prior to 2016. The cumulative impacts of these rules through 2023 and 2026 were incorporated into the projected emissions for CMV sources. The CMV emissions were split into emissions inventories from the larger C3 engines, and those from the smaller category 1 and 2 (C1C2) engines. CMV emissions in California are based on emissions provided by the state. The CMV emissions are consistent with the emissions for the 2016v1 platform updated CMV emissions released by February 2020 although they include projected emissions for the years of 2023 and 2026 instead of 2023 and 2028. In addition, in response to comments, the EPA implemented an improved process for spatial allocating CMV emissions along state and county boundaries.

6. Development of Emissions Inventories for Other Nonroad Mobile Sources

The EPA developed nonroad mobile source emissions inventories (other than CMV, locomotive, and aircraft emissions) for 2016, 2023, and 2026 from monthly, county, and process level emissions output from MOVES3. Types of nonroad equipment include recreational vehicles, pleasure craft, and construction, agricultural, mining, and lawn and garden equipment. State-submitted emissions data for nonroad sources were used for California. The nonroad emissions for the final rule were unchanged from those at the proposal. The nonroad mobile emissions control programs include reductions to locomotives, diesel engines, and recreational marine engines, along with standards for fuel sulfur content and evaporative emissions. A comprehensive list of control programs included for mobile sources is available in the 2016v3 Emissions Modeling TSD.

Line haul locomotives are also considered a type of nonroad mobile source but the emissions inventories for locomotives were not developed using MOVES3. Year 2016 locomotive emissions were developed through the 2016v1 collaborative process and the year 2016 emissions are mostly consistent with those in the 2017 NEI. More information on the development of the Class I, Class II and III, and commuter rail line haul locomotive emissions is available in the 2016v3 Emissions Modeling TSD. The projected locomotive emissions for 2023 and 2026 were developed by applying factors to the 2016 emissions using activity data based on AEO freight rail energy use growth rate projections along with emissions rates adjusted to account for recent historical trends. The emission factors used for NO_X, PM10 and VOC for line haul locomotives in the analytic years were derived from trend lines based on historic line-haul emission factors from the period of 2007 through 2017 and extrapolated to 2023 and 2026.

7. Development of Emissions Inventories for Nonpoint Sources

For stationary nonpoint sources, some emissions in the 2016 base case emissions inventory come directly from the 2017 NEI, others were adjusted from the 2017 NEI to represent 2016 levels, and the remaining emissions including those from oil and gas, fertilizer, and solvents were computed specifically to represent 2016. Stationary nonpoint sources include evaporative sources, consumer products, fuel combustion that is not captured by point sources, agricultural livestock, agricultural fertilizer, residential wood combustion, fugitive dust, and oil and gas sources. The emissions sources derived from the 2017 NEI include agricultural livestock, fugitive dust, residential wood combustion, waste disposal (including composting), bulk gasoline terminals, and miscellaneous non-industrial sources such as cremation, hospitals, lamp breakage, and automotive repair shops. A recent method to compute solvent VOC emissions was used.[150]

Where comments were provided about projected control measures or

[150] *https://doi.org/10.5194/acp-21-5079-2021.*

changes in nonpoint source emissions, those inputs were first reviewed by the EPA. Those found to be based on reasonable data for affected emissions sources were incorporated into the projected inventories for 2023 and 2026 to the extent possible. Where possible, projection factors based on the AEO used data from AEO 2022, the most recent AEO at the time available at the time the inventories were developed. Federal regulations that impact the nonpoint sources were reflected in the inventories. Adjustments for state fuel sulfur content rules for fuel oil in the Northeast were included along with solvent controls applicable within the ozone transport region. Details are available in the 2016v3 Emissions Modeling TSD.

Nonpoint oil and gas emissions inventories for many states were developed based on outputs from the 2017 NEI version of the EPA Oil and Gas Tool using activity data for year 2016. Production-related emissions data from the 2017 NEI were used for Oklahoma, 2016v1 emissions were used for Colorado and for Texas production-related sources to response to comments. Data for production-related nonpoint oil and gas emissions in the states of Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, and Wyoming were obtained from the WRAP baseline inventory.[151] A California Air Resources Board-provided inventory was used for 2016 oil and gas emissions in California. Nonpoint oil and gas inventories for 2023 and 2026 were developed by first projecting the 2016 oil and gas inventories to 2021 values based on actual production data. Next, those 2021 emissions were projected to 2023 and 2026 using regional projection factors by product type based on AEO 2022 projections. A 2017–2019 average inventory was used for oil and natural gas exploration emissions in 2023 and 2026 except for California and in the WRAP states in which data from the WRAP future year inventory [152] were used. NO_X and VOC reductions that are co-benefits to the NSPS for RICE are reflected, along with Natural Gas Turbines and Process Heaters NSPS NO_X controls and NSPS Oil and Gas VOC controls. The WRAP future year inventory was used for oil and natural gas production sources in 2023 and 2026 except in New Mexico where the WRAP Base year emissions were projected using the EIA historical and AEO forecasted production data. Estimated impacts from the New Mexico Administrative Code 20.2.50 were included.

D. Air Quality Modeling To Identify Nonattainment and Maintenance Receptors

In this section, the Agency describes the air quality modeling and analyses performed in Step 1 to identify locations where the Agency expects there to be nonattainment or maintenance receptors for the 2015 ozone NAAQS in the 2023 and 2026 analytic years. Where the EPA's analysis shows that an area or site does not fall under the definition of a nonattainment or maintenance receptor in these analytic years, that site is excluded from further analysis under this rule.

In the proposed rule, the EPA applied the same approach used in the CSAPR Update and the Revised CSAPR Update to identify nonattainment and maintenance receptors for the 2008 ozone NAAQS.[153] *See* 86 FR 23078–79. The EPA's approach gives independent effect to both the ''contribute significantly to nonattainment'' and the ''interfere with maintenance'' prongs of section 110(a)(2)(D)(i)(I), consistent with the D.C. Circuit's direction in *North Carolina.*[154] Further, in its decision on the remand of the CSAPR from the Supreme Court in the *EME Homer City* case, the D.C. Circuit confirmed that EPA's approach to identifying maintenance receptors in the CSAPR comported with the court's prior instruction to give independent meaning to the ''interfere with maintenance'' prong in the good neighbor provision. *EME Homer City II,* 795 F.3d at 136.

In the CSAPR Update and the Revised CSAPR Update, the EPA identified nonattainment receptors as those monitoring sites that are projected to have average design values that exceed the NAAQS and that are also measuring nonattainment based on the most recent monitored design values. This approach is consistent with prior transport rulemakings, such as the NO_X SIP Call and CAIR, where the EPA defined nonattainment receptors as those areas that both currently monitor nonattainment and that the EPA projects will be in nonattainment in the future compliance year.[155]

The Agency explained in the NO_X SIP Call and CAIR and then reaffirmed in the CSAPR Update that the EPA has the most confidence in our projections of nonattainment for those monitoring sites that also measure nonattainment for the most recent period of available ambient data. The EPA separately identified maintenance receptors as those monitoring sites that would have difficulty maintaining the relevant NAAQS in a scenario that accounts for historical variability in air quality at that site. The variability in air quality was determined by evaluating the ''maximum'' future design value at each monitoring site based on a projection of the maximum measured design value over the relevant period. The EPA interprets the projected maximum future design value to be a potential future air quality outcome consistent with the meteorology that yielded maximum measured concentrations in the ambient data set analyzed for that receptor (*i.e.,* ozone conducive meteorology). The EPA also recognizes that previously experienced meteorological conditions (*e.g.,* dominant wind direction, temperatures, and air mass patterns) promoting ozone formation that led to maximum concentrations in the measured data may reoccur in the future. The maximum design value gives a reasonable projection of future air quality at the receptor under a scenario in which such conditions do, in fact, reoccur.[156] The projected maximum design value is used to identify upwind emissions that, under those circumstances, could interfere with the downwind area's ability to maintain the NAAQS.

Therefore, applying this methodology in this rule, the EPA assessed the magnitude of the projected maximum design values for 2023 and 2026 at each monitoring site in relation to the 2015 ozone NAAQS and, where such a value exceeds the NAAQS, the EPA determined that receptor to be a ''maintenance'' receptor for purposes of defining interference with maintenance, consistent with the method used in CSAPR and upheld by the D.C. Circuit in *EME Homer City II.*[157] That is,

[151] *http://www.wrapair2.org/pdf/WRAP_OGWG_Report_Baseline_17Sep2019.pdf.*

[152] *http://www.wrapair2.org/pdf/WRAP_OGWG_2028_OTB_RevFinalReport_05March2020.pdf.*

[153] *See* 86 FR 23078–79.

[154] 531 F.3d at 910–911 (holding that the EPA must give ''independent significance'' to each prong of CAA section 110(a)(2)(D)(i)(I)).

[155] *See* 63 FR 57375, 57377 (October 27, 1998); 70 FR 25241 (January 14, 2005). *See also North Carolina,* 531 F.3d at 913–914 (affirming as reasonable EPA's approach to defining nonattainment in CAIR).

[156] The EPA's air quality modeling guidance identifies the use of the highest of the relevant base period design values as a means to evaluate future year attainment under meteorological conditions that are especially conducive to ozone formation. *See* U.S. Environmental Protection Agency, 2018. Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze, Research Triangle Park, NC.

[157] *See* 795 F.3d at 136.

monitoring sites with a maximum design value that exceeds the NAAQS are projected to have maintenance problems in the future analytic years.[158]

Recognizing that nonattainment receptors are also, by definition, maintenance receptors, the EPA often uses the term ''maintenance-only'' to refer to receptors that are not also nonattainment receptors. Consistent with the concepts for maintenance receptors, as described previously, the EPA identifies ''maintenance-only'' receptors as those monitoring sites that have projected average design values above the level of the applicable NAAQS, but that are not currently measuring nonattainment based on the most recent official design values. In addition, those monitoring sites with projected average design values below the NAAQS, but with projected maximum design values above the NAAQS are also identified as ''maintenance only'' receptors, even if they are currently measuring nonattainment based on the most recent official design values.[159]

Comment: The EPA received comments claiming that the projected design values for 2023 were biased low compared to recent measured data. Commenters noted that a number of monitoring sites that are projected to be below the NAAQS in 2023 based on the EPA's modeling for the proposed action are currently measuring nonattainment based on data from 2020 and 2021. One commenter requested that the EPA determine whether its past modeling tends to overestimate or underestimated actual observed design values. If EPA finds that the agency's model tends to underestimate future year design values, the commenter requests that EPA re-run its ozone modeling, incorporating parameters that account for this tendency.

Response: In response to comments, the EPA compared the projected 2023 design values based on the proposal modeling to recent trends in measured data. As a result of this analysis, the EPA agrees that current data indicate that there are monitoring sites at risk of continued nonattainment in 2023 even though the model projected average and maximum design values at these sites are below the NAAQS (*i.e.,* sites that are not modeling-based receptors). It would not be reasonable to ignore recent measured ozone levels in many areas that are clearly not fully consistent with certain concentrations in the Step 1 analysis for 2023. Therefore, the EPA has also developed an additional maintenance-only receptor category, which includes what we refer to as ''violating monitor'' receptors, based on current ozone concentrations measured by regulatory ambient air quality monitoring sites.

Specifically, the EPA has identified monitoring sites with measured 2021 and preliminary 2022 design values *and* 4th high maximum daily 8-hour average (MDA8) ozone in both 2021 and 2022 (preliminary data) that exceed the NAAQS, although projected to be in attainment in 2023, as having the greatest risk of continuing to have a problem attaining the standard in 2023. These criteria sufficiently consider measured air quality data so as to avoid including monitoring sites that have measured nonattainment data in recent years but could reasonably be anticipated to not have a nonattainment or maintenance problem in 2023, in line with our modeling results. Our methodology is intended only to identify those sites that have sufficiently poor ozone levels that there is clearly a reasonable expectation that an ozone nonattainment or maintenance problem will persist in the 2023 ozone season. Moreover, 2023 is so near in time that recent measured ozone levels can be used to reasonably project whether an air quality problem is likely to persist. We view this approach to identifying additional receptors in 2023 as the best means of responding to the comments on this issue in this action, while also identifying all transport receptors.

For purposes of this action, we treat these violating monitors as an additional type of maintenance-only receptor. Because our modeling did not identify these sites as receptors, we do not believe it is sufficiently certain that these sites will be in nonattainment such that they should be considered nonattainment receptors. Rather, our authority for treating these sites as receptors in 2023 flows from the responsibility in CAA section 110(a)(2)(i)(I) to prohibit emissions that interfere with maintenance of the NAAQS. *See, e.g., North Carolina,* 531 F.3d at 910–11 (failing to give effect to the interfere with maintenance clause ''provides no protection for downwind areas that, *despite EPA's predictions,* still find themselves struggling to meet NAAQS due to upwind interference . . . .'') (emphasis added). Recognizing that no modeling can perfectly forecast the future, and ''a degree of imprecision is inevitable in tackling the problem of interstate air pollution,'' this approach in the Agency's judgement best balances the need to avoid both ''under-control'' and ''overcontrol,'' *EME Homer City,* 572 U.S. at 523.

We acknowledge that the traditional modeling plus monitoring methodology we used at proposal and in prior ozone transport rules would otherwise have identified such sites as being in attainment in 2023. Despite the implications of the current measured data suggesting there will be a nonattainment problem at these sites in 2023, we cannot definitively establish that such sites will be in nonattainment in 2023 in light of our modeling projections. In the face of this uncertainty, we regard our ability to consider such sites as receptors for purposes of good neighbor analysis under CAA section 110(a)(2)(D)(i)(I) to be a function of the requirement to prohibit emissions that interfere with maintenance of the NAAQS; even if an area may be technically in attainment, we have reliable information indicating that there is an identified risk that attainment will not in fact be achieved.

[158] The EPA issued a memorandum in October 2018, providing additional information to states developing interstate transport SIP submissions for the 2015 8-hour ozone NAAQS concerning considerations for identifying downwind areas that may have problems maintaining the standard at Step 1 of the 4-step interstate transport framework. *See* Considerations for Identifying Maintenance Receptors for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards, October 19, 2018 (''October 2018 memorandum''), available in Docket No. EPA–HQ–OAR–2021–0668 or at *https://www.epa.gov/airmarkets/memo-and-supplemental-information-regarding-interstate-transport-sips-2015-ozone-naaqs.* EPA is not applying the suggested analytical approaches in that memorandum in this rule, nor would those approaches be appropriate in light of currently available data. Potential alternative approaches would introduce unnecessary and substantial additional analytical burdens that could frustrate timely and efficient implementation of good neighbor obligations. In addition, the information supplied in that memorandum is now outdated due to several additional years of air quality monitoring data and updated modeling results. EPA's current approach to defining ''maintenance'' receptors has been upheld and continues to provide an appropriate approach to addressing the ''interference with maintenance'' prong of the Good Neighbor provision. *See EME Homer City,* 795 F.3d 118, 136–37; *Wisconsin,* 938 F.3d at 325–26.

[159] See *https://www.epa.gov/air-trends/air-quality-design-values* for design value reports. At the time of this action, the most recent reports available are for the calendar year 2021.

However, because we did not identify this basis for receptor-identification at proposal, in this final action we are only using this receptor category on a confirmatory basis. That is, for states that we find linked based on our traditional modeling-based methodology in 2023, we find in this final analysis that the linkage at Step 2 is strengthened and confirmed if that state is also linked to one or more ''violating monitor'' receptors. If a state is only linked to a violating-monitor receptor in this final analysis, we are deferring taking final action on that state's SIP submittal. This is the case for the State of Tennessee. Among the states that previously had their transport SIPs fully approved for the 2015 ozone NAAQS, the EPA has also identified a linkage to violating-monitor receptors for the State of Kansas. The EPA intends to further review its air quality modeling results and recent measured ozone levels, and we intend to address these states' good neighbor obligations as expeditiously as practicable in a future action.

E. Methodology for Projecting Future Year Ozone Design Values

Consistent with the EPA's modeling guidance, the 2016 base year and future year air quality modeling results were used in a relative sense to project design values for 2023 and 2026. That is, the ratios of future year model predictions to base year model predictions are used to adjust ambient ozone design values [160] up or down depending on the relative (percent) change in model predictions for each location. The modeling guidance recommends using measured ozone concentrations for the 5-year period centered on the base year as the air quality data starting point for future year projections. This average design value is used to dampen the effects of inter-annual variability in meteorology on ozone concentrations and to provide a reasonable projection of future air quality at the receptor under average conditions. In addition, the Agency calculated maximum design values from within the 5-year base period to represent conditions when meteorology is more favorable than average for ozone formation. Because the base year for the air quality modeling used in this final rule is 2016, measured data for 2014–2018 (*i.e.,* design values for 2016, 2017, and 2018) were used to project average and maximum design values in 2023 and 2026.

The ozone predictions from the 2016 and future year air quality model simulations were used to project 2016–2018 average and maximum ozone design values to 2023 and 2026 using an approach similar to the approach in EPA's guidance for attainment demonstration modeling. This guidance recommends using model predictions from the 3 x 3 array of grid cells [161] surrounding the location of the monitoring site to calculate a Relative Response Factor (RRF) for that site.[162] However, the guidance also notes that an alternative array of grid cells may be used in certain situations where local topographic or geographical feature (*e.g.,* a large water body or a significant elevation change) may influence model response.

The 2016–2018 base period average and maximum design values were multiplied by the RRF to project each of these design values to each of the three future years. In this manner, the projected design values are grounded in monitored data, and not the absolute model-predicted future year concentrations. Following the approach in the CSAPR Update and the Revised CSAPR Update, the EPA also projected future year design values based on a modified version of the ''3 × 3'' approach for those monitoring sites located in coastal areas. In this alternative approach, the EPA eliminated from the RRF calculations the modeling data in those grid cells that are dominated by water (*i.e.,* more than 50 percent of the area in the grid cell is water) and that do not contain a monitoring site (*i.e.,* if a grid cell is more than 50 percent water but contains an air quality monitor, that cell would remain in the calculation). The choice of more than 50 percent of the grid cell area as water as the criteria for identifying overwater grid cells is based on the treatment of land use in the Weather Research and Forecasting model (WRF).[163] Specifically, in the WRF meteorological model those grid cells that are greater than 50 percent overwater are treated as being 100 percent overwater. In such cases the meteorological conditions in the entire grid cell reflect the vertical mixing and winds over water, even if part of the grid cell also happens to be over land with land-based emissions, as can often be the case for coastal areas. Overlaying land-based emissions with overwater meteorology may be representative of conditions at coastal monitors during times of on-shore flow associated with synoptic conditions or sea-breeze or lake-breeze wind flows. But there may be other times, particularly with off-shore wind flow, when vertical mixing of land-based emissions may be too limited due to the presence of overwater meteorology. Thus, for our modeling the EPA projected average and maximum design values at individual monitoring sites based on both the ''3 × 3'' approach as well as the alternative approach that eliminates overwater cells in the RRF calculation for near-coastal areas (*i.e.,* ''no water'' approach). The projected 2023 and 2026 design values using both the ''3 × 3'' and ''no-water'' approaches are provided in the docket for this final rule. For this final rule, the EPA is relying upon design values based on the ''no water'' approach for identifying nonattainment and maintenance receptors.[164]

Consistent with the truncation and rounding procedures for the 8-hour ozone NAAQS, the projected design values are truncated to integers in units of ppb.[165] Therefore, projected design values that are greater than or equal to 71 ppb are considered to be violating the 2015 ozone NAAQS. For those sites that are projected to be violating the NAAQS based on the average design values in the future analytic years, the Agency examined the measured design values for 2021, which are the most recent official measured design values at the time of this final rule. As noted earlier, the Agency is identifying nonattainment receptors in this rulemaking as those sites that are violating the NAAQS based on current

[160] The ozone design value at a particular monitoring site is the 3-year average of the annual 4th highest daily maximum 8-hour ozone concentration at that site.

[161] As noted in this section, each model grid cell is 12 x 12 km.

[162] The relative response factor represents the change in ozone at a given site. To calculate the RRF, the EPA's modeling guidance recommends selecting the 10 highest ozone days in an ozone season at a given monitor in the base year, noting which of the grid cells surrounding the monitor experienced the highest ozone concentrations in the base year, and averaging those ten highest concentrations. The model is then run using the projected year emissions, in this case 2023, with all other model variables held constant. Ozone concentrations from the same ten days, in the same grid cells, are then averaged. The fractional change between the base year (2016 model run) average ozone concentration and the future year (*e.g.,* 2023 model run) average ozone concentration represents the relative response factor.

[163] *https://www.mmm.ucar.edu/weather-research-and-forecasting-model.*

[164] Using design values from the ''3 × 3'' approach, the maintenance-only receptor at site 550590019 in Kenosha County, WI would become a nonattainment receptor because the average design value with the ''3 × 3'' approach is 72.0 ppb versus 70.8 ppb with the ''no water'' approach. In addition, the maintenance-only receptor at site 090099002 in New Haven County, CT would become a nonattainment receptor using the ''3 × 3'' approach because the average design value with the ''3 × 3'' approach is 71.2 ppb versus 70.5 ppb with the ''no water'' approach.

[165] 40 CFR part 50, appendix P—Interpretation of the Primary and Secondary National Ambient Air Quality Standards for Ozone.

measured air quality and also have projected average design values of 71 ppb or greater. Maintenance-only receptors include both (1) those sites with projected average design values above the NAAQS that are currently measuring clean data (*i.e.,* ozone design values below the level of the 2015 ozone NAAQS) and (2) those sites with projected average design values below the level of the NAAQS, but with projected maximum design values of 71 ppb or greater. In addition to the maintenance-only receptors, ozone nonattainment receptors are also maintenance receptors because the maximum design values for each of these sites is always greater than or equal to the average design value. The monitoring sites that the Agency projects to be nonattainment and maintenance receptors for the ozone NAAQS in the 2023 and 2026 base case are used for assessing the contribution of emissions in upwind states to downwind nonattainment and maintenance of the 2015 ozone NAAQS as part of this final rule.[166]

Table IV.D–1 contains the 2016-centered [167] base period average and maximum 8-hour ozone design values, the 2023 base case average and maximum design values and the measured 2021 design values for the sites that are projected to be nonattainment receptors in 2023. Table IV.D–2 contains this same information for monitoring sites that are projected to be maintenance-only receptors in 2023. The design values for all monitoring sites in the U.S. are provided in the docket for this rule. Additional details on the approach for projecting average and maximum design values are provided in the Air Quality Modeling Final Rule TSD.

TABLE IV.D–1—AVERAGE AND MAXIMUM 2016-CENTERED AND 2023 BASE CASE 8-HOUR OZONE DESIGN VALUES AND 2021 DESIGN VALUES (ppb) AT PROJECTED NONATTAINMENT RECEPTORS

Monitor ID	State	County	2016 Centered average	2016 Centered maximum	2023 Average	2023 Maximum	2021
060650016	CA	Riverside	79.0	80.0	72.2	73.1	78
060651016	CA	Riverside	99.7	101.0	91.0	92.2	95
080350004	CO	Douglas	77.3	78	71.3	71.9	83
080590006	CO	Jefferson	77.3	78	72.8	73.5	81
080590011	CO	Jefferson	79.3	80	73.5	74.1	83
090010017	CT	Fairfield	79.3	80	71.6	72.2	79
090013007	CT	Fairfield	82.0	83	72.9	73.8	81
090019003	CT	Fairfield	82.7	83	73.3	73.6	80
481671034	TX	Galveston	75.7	77	71.5	72.8	72
482010024	TX	Harris	79.3	81	75.1	76.7	74
490110004	UT	Davis	75.7	78	72.0	74.2	78
490353006	UT	Salt Lake	76.3	78	72.6	74.2	76
490353013	UT	Salt Lake	76.5	77	73.3	73.8	76
551170006	WI	Sheboygan	80.0	81	72.7	73.6	72

TABLE IV.D–2—AVERAGE AND MAXIMUM 2016-CENTERED AND 2023 BASE CASE 8-HOUR OZONE DESIGN VALUES AND 2021 DESIGN VALUES (ppb) AT PROJECTED MAINTENANCE-ONLY RECEPTORS

Monitor ID	State	County	2016 Centered average	2016 Centered maximum	2023 Average	2023 Maximum	2021
040278011	AZ	Yuma	72.3	74	70.4	72.1	67
080690011	CO	Larimer	75.7	77	70.9	72.1	77
090099002	CT	New Haven	79.7	82	70.5	72.6	82
170310001	IL	Cook	73.0	77	68.2	71.9	71
170314201	IL	Cook	73.3	77	68.0	71.5	74
170317002	IL	Cook	74.0	77	68.5	71.3	73
350130021	NM	Dona Ana	72.7	74	70.8	72.1	80
350130022	NM	Dona Ana	71.3	74	69.7	72.4	75
350151005	NM	Eddy	69.7	74	69.7	74.1	77
350250008	NM	Lea	67.7	70	69.8	72.2	66
480391004	TX	Brazoria	74.7	77	70.4	72.5	75
481210034	TX	Denton	78.0	80	69.8	71.6	74
481410037	TX	El Paso	71.3	73	69.8	71.4	75
482010055	TX	Harris	76.0	77	70.9	71.9	77
482011034	TX	Harris	73.7	75	70.1	71.3	71
482011035	TX	Harris	71.3	75	67.8	71.3	71
530330023	WA	King	73.3	77	67.6	71.0	64
550590019	WI	Kenosha	78.0	79	70.8	71.7	74
551010020	WI	Racine	76.0	78	69.7	71.5	73

[166] In addition, there are 71 monitoring sites in California with projected 2023 maximum design values above the NAAQS. With two exceptions, as described in section IV.F of this document, the Agency is not making a determination in this action that these monitors are ozone transport receptors. The two exceptions are the two monitoring sites that represent air quality impacts to lands of the Morongo and Pechanga tribes. As explained in footnote 110 supra, we treat these as transport receptors that are impacted by emissions from California.

[167] 2016-centered averaged design values represent the average of the design values for 2016, 2017, and 2018. Similarly, the maximum 2016-centered design value is the highest measured design value from these three design value periods.

In total, in the 2023 base case there are a total of 33 projected modeling-based receptors nationwide including 14 nonattainment receptors in 9 different counties and 19 maintenance-only receptors in 13 additional counties (Harris County, TX, has both nonattainment and maintenance-only receptors).[168] Of the 14 nonattainment receptors in 2023, 7 remain nonattainment receptors, 5 are projected to become maintenance-only receptors and 2 are projected to be in attainment in 2026. Of the 19 maintenance-only receptors in 2023, 7 are projected to remain maintenance-only receptors and 12 are projected to be in attainment in 2026. The projected average and maximum design values in 2026 for all receptors are included in the Air Quality Modeling Final Rule TSD.

Comment: EPA received comments saying that the projected design values for 2023 were biased low compared to recent measured data. Commenters noted that a number of monitoring sites that are projected to be below the NAAQS in 2023 based on EPA's modeling for the proposed rule are currently measuring nonattainment. Because 2023 is only a year later than the most recent measured data some commenters said that EPA should give greater weight to measured data when identifying downwind receptors.

Response: Based on an analysis of model projections for 2023 and recent trends in measured data, the EPA agrees that current data indicate that there are monitoring sites at risk of continued nonattainment in 2023 even though the model projected average and maximum design values at these sites are below the NAAQS (*i.e.,* sites that are not modeling-based receptors).[169] Specifically, the EPA believes that monitoring sites with measured design values *and* 4th high maximum daily 8-hour average (MDA8) ozone based on 2021 *and* preliminary 2022 data have the greatest risk of continuing to have a problem attaining the standard in 2023, even when the modeling projects these sites will attain. These criteria are sufficiently conservative that we avoid including monitoring sites that have measured nonattainment data in recent years but could reasonably be anticipated to not have a nonattainment or maintenance problem in 2023, in line with our modeling results. Our methodology is intended only to identify those sites that have sufficiently poor ozone levels that there is clearly a reasonable expectation that an ozone nonattainment or maintenance problem will persist in the 2023 ozone season. We do not apply this methodology for the 2026 analytic year, because that year is sufficiently farther in the future that we do not believe there would be a reasonable basis to supplement our modeling analysis with this ''violating monitor'' methodology. By comparison, 2023 is so near in time that recent measured ozone levels can be used reasonably to project whether an air quality problem is likely to persist. We view this approach to identifying additional receptors in 2023 as the best means of responding to the comments on this issue in this action. The monitoring sites that meet these criteria, along with the corresponding measured and modeled data, are provided in Table IV.D–3.

For purposes of this action, we will treat these sites as an additional type of maintenance-only receptor. Because our modeling did not identify these sites as receptors, we do not believe it is sufficiently certain that these sites will be in nonattainment that they should be considered nonattainment receptors for purposes of this final rule. Rather, our authority for treating these sites as receptors in 2023 flows from the responsibility in CAA section 110(a)(2)(i)(I) to prohibit emissions that interfere with maintenance of the NAAQS. *See, e.g., North Carolina,* 531 F.3d at 910–11 (failing to give effect to the interfere with maintenance clause ''provides no protection for downwind areas that, *despite EPA's predictions,* still find themselves struggling to meet NAAQS due to upwind interference . . . .'') (emphasis added). Recognizing that no modeling can perfectly forecast the future, and ''a degree of imprecision is inevitable in tackling the problem of interstate air pollution,'' this approach in the Agency's judgement best balances the need to avoid both ''under-control'' and ''overcontrol,'' *EME Homer City,* 572 U.S. at 523.

In this action, we identify ''violating monitor'' maintenance-only receptors for purposes of more firmly establishing that the states we have otherwise identified as linked at Step 2 in our modeling-based methodology can indeed be reasonably anticipated to be linked to air quality problems in downwind states in 2023 for reasons that extend beyond that methodology. In this sense, this approach is ''confirmatory'' and does not alter the geography of the final rule compared to the application of the modeling-based receptor definitions used at proposal. Rather, it strengthens the analytical basis for our Step 2 findings by establishing that many upwind states covered in this action are also projected to contribute above 1 percent of the NAAQS to these types of receptors. For purposes of this final rule, we will not finalize FIPs for any states that this analysis indicates contribute greater than 1 percent of the NAAQS only to a ''violating monitor'' receptor. Our analysis suggests this would be the case for two states, Kansas and Tennessee (see section IV.F of this document).[170] We are making no final decisions with respect to these states in this action and intend to address these states in a subsequent action.

TABLE IV.D–3—AVERAGE AND MAXIMUM 2023 BASE CASE 8-HOUR OZONE, AND 2021 AND PRELIMINARY 2022 DESIGN VALUES (ppb) AND 4TH HIGH CONCENTRATIONS AT VIOLATING MONITORS

Monitor ID	State	County	2023 Average	2023 Maximum	2021	2022 P *	2021 4th high	2022 P 4th high
40070010	AZ	Gila	67.9	69.5	77	76	75	74

[168] The EPA's modeling also projects that three monitoring sites in the Uintah Basin (*i.e.,* monitor 490472003 in Uintah County, Utah, and monitors 490130002 and 490137011 in Duchesne County, Utah) will have average design values above the NAAQS in 2023. However, as noted in the proposed rule, the Uinta Basin nonattainment area was designated as nonattainment for the 2015 ozone NAAQS not because of an ongoing problem with summertime ozone (as is usually the case in other parts of the country), but instead because it violates the ozone NAAQS in winter. The main causes of the Uinta Basin's wintertime ozone are sources located at low elevations within the Basin, the Basin's unique topography, and the influence of the wintertime meteorologic inversions that keep ozone and ozone precursors near the Basin floor and restrict air flow in the Basin. Because of the localized nature of the ozone problem at these sites the EPA has not identified these three monitors as receptors in Step 1 of this final rule.

[169] In addition, we note that comparing the projected 2023 maximum design values at modeling-based receptors listed in Table IV.D–1 and Table IV.D–2 to the 2021 design values measured at these sites indicates that the projected maximum values are lower than the measured data at most receptors. These differences are particularly evident at receptors in coastal Connecticut and in Denver. (See Air Quality Modeling Final Rule TSD for details).

[170] We have not conducted an analysis in this action to determine whether violating-monitor receptors may exist in California.

TABLE IV.D–3—AVERAGE AND MAXIMUM 2023 BASE CASE 8-HOUR OZONE, AND 2021 AND PRELIMINARY 2022 DESIGN VALUES (ppb) AND 4TH HIGH CONCENTRATIONS AT VIOLATING MONITORS—Continued

Monitor ID	State	County	2023 Average	2023 Maximum	2021	2022 P *	2021 4th high	2022 P 4th high
40130019	AZ	Maricopa	69.8	70.0	75	77	78	76
40131003	AZ	Maricopa	70.1	70.7	80	80	83	78
40131004	AZ	Maricopa	70.2	70.8	80	81	81	77
40131010	AZ	Maricopa	68.3	69.2	79	80	80	78
40132001	AZ	Maricopa	63.8	64.1	74	78	79	81
40132005	AZ	Maricopa	69.6	70.5	78	79	79	77
40133002	AZ	Maricopa	65.8	65.8	75	75	81	72
40134004	AZ	Maricopa	65.7	66.6	73	73	73	71
40134005	AZ	Maricopa	62.3	62.3	73	75	79	73
40134008	AZ	Maricopa	65.6	66.5	74	74	74	71
40134010	AZ	Maricopa	63.8	66.9	74	76	77	75
40137020	AZ	Maricopa	67.0	67.0	76	77	77	75
40137021	AZ	Maricopa	69.8	70.1	77	77	78	75
40137022	AZ	Maricopa	68.2	69.1	76	78	76	79
40137024	AZ	Maricopa	67.0	67.9	74	76	74	77
40139702	AZ	Maricopa	66.9	68.1	75	77	72	77
40139704	AZ	Maricopa	65.3	66.2	74	77	76	76
40139997	AZ	Maricopa	70.5	70.5	76	79	82	76
40218001	AZ	Pinal	67.8	69.0	75	76	73	77
80013001	CO	Adams	63.0	63.0	72	77	79	75
80050002	CO	Arapahoe	68.0	68.0	80	80	84	73
80310002	CO	Denver	63.6	64.8	72	74	77	71
80310026	CO	Denver	64.5	64.8	75	77	83	72
90079007	CT	Middlesex	68.7	69.0	74	73	78	73
90110124	CT	New London	65.5	67.0	73	72	75	71
170310032	IL	Cook	67.3	69.8	75	75	77	72
170311601	IL	Cook	63.8	64.5	72	73	72	71
181270024	IN	Porter	63.4	64.6	72	73	72	73
260050003	MI	Allegan	66.2	67.4	75	75	78	73
261210039	MI	Muskegon	67.5	68.4	74	79	75	82
320030043	NV	Clark	68.4	69.4	73	75	74	74
350011012	NM	Bernalillo	63.8	66.0	72	73	76	74
350130008	NM	Dona Ana	65.6	66.3	72	76	79	78
361030002	NY	Suffolk	66.2	68.0	73	74	79	74
390850003	OH	Lake	64.3	64.6	72	74	72	76
480290052	TX	Bexar	67.1	67.8	73	74	78	72
480850005	TX	Collin	65.4	66.0	75	74	81	73
481130075	TX	Dallas	65.3	66.5	71	71	73	72
481211032	TX	Denton	65.9	67.7	76	77	85	77
482010051	TX	Harris	65.3	66.3	74	73	83	72
482010416	TX	Harris	68.8	70.4	73	73	78	71
484390075	TX	Tarrant	63.8	64.7	75	76	76	77
484391002	TX	Tarrant	64.1	65.7	72	77	76	80
484392003	TX	Tarrant	65.2	65.9	72	72	74	72
484393009	TX	Tarrant	67.5	68.1	74	75	75	75
490571003	UT	Weber	69.3	70.3	71	74	77	71
550590025	WI	Kenosha	67.6	70.7	72	73	72	71
550890008	WI	Ozaukee	65.2	65.8	71	72	72	72

* 2022 preliminary design values are based on 2022 measured MDA8 concentrations provided by state air agencies to the EPA's Air Quality System (AQS), as of January 3, 2023.

F. Pollutant Transport From Upwind States

1. Air Quality Modeling To Quantify Upwind State Contributions

This section documents the procedures the EPA used to quantify the impact of emissions from specific upwind states on ozone design values in 2023 and 2026 for the identified downwind nonattainment and maintenance receptors. The EPA used CAMx photochemical source apportionment modeling to quantify the impact of emissions in specific upwind states on downwind nonattainment and maintenance receptors for 8-hour ozone. CAMx employs enhanced source apportionment techniques that track the formation and transport of ozone from specific emissions sources and calculates the contribution of sources and precursors to ozone for individual receptor locations. The benefit of the photochemical model source apportionment technique is that all modeled ozone at a given receptor location in the modeling domain is tracked back to specific sources of emissions and boundary conditions to fully characterize culpable sources.

The EPA performed nationwide, state-level ozone source apportionment modeling using the CAMx Ozone Source Apportionment Technology/Anthropogenic Precursor Culpability Analysis (OSAT/APCA) technique [171] to quantify the contribution of 2023 and 2026 base case NO_X and VOC emissions from all sources in each state to the

[171] As part of this technique, ozone formed from reactions between biogenic VOC and NO_X with anthropogenic NO_X and VOC are assigned to the anthropogenic emissions.

corresponding projected ozone design values in 2023 and 2026 at air quality monitoring sites. The CAMx OSAT/APCA model run was performed for the period May 1 through September 30 using the projected future base case emissions and 2016 meteorology for this time period. In the source apportionment modeling the Agency tracked (*i.e.,* tagged) the amount of ozone formed from anthropogenic emissions in each state individually as well as the contributions from other sources (*e.g.,* natural emissions).

In the state-by-state source apportionment model runs, the EPA tracked the ozone formed from each of the following tags:

- States—anthropogenic NO_X and VOC emissions from each state tracked individually (emissions from all anthropogenic sectors in a given state were combined);
- Biogenics—biogenic NO_X and VOC emissions domain-wide (*i.e.,* not by state);
- Boundary Concentrations—concentrations transported into the air quality modeling domain;
- Tribes—the emissions from those tribal lands for which the Agency has point source inventory data in the 2016v3 emissions modeling platform (EPA did not model the contributions from individual tribes);
- Canada and Mexico—anthropogenic emissions from sources in the portions of Canada and Mexico included in the modeling domain (the EPA did not model the contributions from Canada and Mexico separately);
- Fires—combined emissions from wild and prescribed fires domain-wide (*i.e.,* not by state); and
- Offshore—combined emissions from offshore marine vessels and offshore drilling platforms.

The contribution modeling provided contributions to ozone from anthropogenic NO_X and VOC emissions in each state, individually. The contributions to ozone from chemical reactions between biogenic NO_X and VOC emissions were modeled and assigned to the ''biogenic'' category. The contributions from wildfire and prescribed fire NO_X and VOC emissions were modeled and assigned to the ''fires'' category. That is, the contributions from the ''biogenic'' and ''fires'' categories are not assigned to individual states nor are they included in the state contributions.

For the Step 2 analysis, the EPA calculated a contribution metric that considers the average contribution on the 10 highest ozone concentration days (*i.e.,* top 10 days) in 2023. This average contribution metric is intended to provide a reasonable representation of the contribution from individual states to projected future year design values, based on modeled transport patterns and other meteorological conditions generally associated with modeled high ozone concentrations at the receptor. An average contribution metric constructed in this manner is beneficial since the magnitude of the contributions is directly related to the magnitude of the design value at each site.

The analytic steps for calculating the contribution metric for the 2023 analytic year are as follows:

(1) Calculate the 8-hour average contribution from each source tag to each monitoring site for the time period of the 8-hour daily maximum modeled concentrations in 2023;

(2) Average the contributions and average the concentrations for the top 10 modeled ozone concentration days in 2023;

(3) Divide the average contribution by the corresponding average concentration to obtain a Relative Contribution Factor (RCF) for each monitoring site;

(4) Multiply the 2023 average design values by the 2023 RCF at each site to produce the average contribution metric values in 2023.[172]

This same approach was applied to calculate contribution metric values at individual monitoring sites for 2026.[173]

The resulting contributions from each tag to each monitoring site in the U.S. for 2023 and 2026 can be found in the docket for this final rule. Additional details on the source apportionment modeling and the procedures for calculating contributions can be found in the Air Quality Modeling Final Rule TSD. The EPA's response to comments on the method for calculating the contribution metric can be found in the *RTC* document for this final rule.

The largest contribution from each state that is the subject of this rule to modeled 8-hour ozone nonattainment and maintenance receptors in downwind states in 2023 and 2026 are provided in Table IV.F–1 and Table IV.F–2, respectively. The largest contribution from each state to a ''violating monitor'' maintenance-only receptor is provided in Table IV.F–3.

TABLE IV.F–1—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS IN 2023

[ppb]

Upwind state	Largest contribution to downwind nonattainment receptors	Largest contribution to downwind maintenance-only receptors
Alabama	0.75	0.65
Arizona	0.54	1.69
Arkansas	0.94	1.21
California	35.27	6.31
Colorado	0.14	0.18
Connecticut	0.01	0.01
Delaware	0.44	0.56
District of Columbia	0.03	0.04
Florida	0.50	0.54
Georgia	0.18	0.17
Idaho	0.42	0.41
Illinois	13.89	19.09

[172] Note that a contribution metric value was not calculated for any receptor at which there were fewer than 5 days with model-predicted MDA8 ozone concentrations greater than or equal to 60 ppb in 2023. The monitoring site in Seattle, King County, Washington (530330023), was the only receptor which did not meet this criterion.

[173] To provide consistency in the contributions for 2023 and 2026, the contribution metric values for 2026 are based on the 2026 daily contributions for the same days that were used to calculate the contribution metric values for 2023.

TABLE IV.F–1—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS IN 2023—Continued

[ppb]

Upwind state	Largest contribution to downwind nonattainment receptors	Largest contribution to downwind maintenance-only receptors
Indiana	8.90	10.03
Iowa	0.67	0.90
Kansas	0.46	0.52
Kentucky	0.84	0.79
Louisiana	9.51	5.62
Maine	0.02	0.01
Maryland	1.13	1.28
Massachusetts	0.33	0.15
Michigan	1.59	1.56
Minnesota	0.36	0.85
Mississippi	1.32	0.91
Missouri	1.87	1.39
Montana	0.08	0.10
Nebraska	0.20	0.36
Nevada	1.11	1.13
New Hampshire	0.10	0.02
New Jersey	8.38	5.79
New Mexico	0.36	1.59
New York	16.10	11.29
North Carolina	0.45	0.66
North Dakota	0.18	0.45
Ohio	2.05	1.98
Oklahoma	0.79	1.01
Oregon *	0.46	0.31
Pennsylvania	6.00	4.36
Rhode Island	0.04	0.01
South Carolina	0.16	0.18
South Dakota	0.05	0.08
Tennessee	0.60	0.68
Texas	1.03	4.74
Utah	1.29	0.98
Vermont	0.02	0.01
Virginia	1.16	1.76
Washington	0.16	0.09
West Virginia	1.37	1.49
Wisconsin	0.21	2.86
Wyoming	0.68	0.67

TABLE IV.F–2—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS IN 2026

[ppb]

Upwind state	Largest contribution to downwind nonattainment receptors	Largest contribution to downwind maintenance-only receptors
Alabama	0.20	0.69
Arizona	0.44	1.34
Arkansas	0.53	1.16
California	34.03	6.16
Colorado	0.04	0.17
Connecticut	0.00	0.01
Delaware	0.43	0.41
District of Columbia	0.03	0.02
Florida	0.46	0.17
Georgia	0.13	0.16
Idaho	0.27	0.36
Illinois	0.63	13.57
Indiana	1.06	8.53
Iowa	0.14	0.62
Kansas	0.14	0.42
Kentucky	0.79	0.76
Louisiana	4.57	9.37

TABLE IV.F–2—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS IN 2026—Continued

[ppb]

Upwind state	Largest contribution to downwind nonattainment receptors	Largest contribution to downwind maintenance-only receptors
Maine	0.00	0.01
Maryland	1.06	0.92
Massachusetts	0.06	0.31
Michigan	1.39	1.47
Minnesota	0.15	0.32
Mississippi	0.29	1.15
Missouri	0.29	1.68
Montana	0.06	0.07
Nebraska	0.09	0.19
Nevada	0.67	0.90
New Hampshire	0.01	0.09
New Jersey	8.10	7.04
New Mexico	0.35	0.46
New York	12.65	12.34
North Carolina	0.40	0.42
North Dakota	0.09	0.17
Ohio	1.95	1.93
Oklahoma	0.19	0.74
Oregon *	0.26	0.41
Pennsylvania	5.47	4.94
Rhode Island	0.00	0.03
South Carolina	0.14	0.15
South Dakota	0.03	0.04
Tennessee	0.24	0.54
Texas	0.48	4.34
Utah	1.05	0.81
Vermont	0.01	0.02
Virginia	1.09	1.10
Washington	0.10	0.14
West Virginia	1.36	1.34
Wisconsin	0.17	0.18
Wyoming	0.40	0.59

TABLE IV.F–3—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE "VIOLATING MONITOR" MAINTENANCE-ONLY RECEPTORS

[ppb]

Upwind state	Largest contribution to downwind violating monitor maintenance-only receptors
Alabama	0.79
Arizona	1.62
Arkansas	1.16
California	6.97
Colorado	0.39
Connecticut	0.17
Delaware	0.42
District of Columbia	0.03
Florida	0.50
Georgia	0.31
Idaho	0.46
Illinois	16.53
Indiana	9.39
Iowa	1.13
Kansas	0.82
Kentucky	1.57
Louisiana	5.06
Maine	0.02
Maryland	1.14
Massachusetts	0.39
Michigan	3.47

TABLE IV.F–3—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE "VIOLATING MONITOR" MAINTENANCE-ONLY RECEPTORS—Continued

[ppb]

Upwind state	Largest contribution to downwind violating monitor maintenance-only receptors
Minnesota	0.64
Mississippi	1.02
Missouri	2.95
Montana	0.12
Nebraska	0.43
Nevada	1.11
New Hampshire	0.10
New Jersey	8.00
New Mexico	0.34
New York	12.08
North Carolina	0.65
North Dakota	0.35
Ohio	2.25
Oklahoma	1.57
Oregon *	0.36
Pennsylvania	5.20
Rhode Island	0.08
South Carolina	0.23
South Dakota	0.12
Tennessee	0.86
Texas	3.83
Utah	1.46
Vermont	0.03
Virginia	1.39
Washington	0.11
West Virginia	1.79
Wisconsin	5.10
Wyoming	0.42

* Does not include California monitoring sites.

2. Application of Contribution Screening Threshold

In Step 2 of the interstate transport framework, the EPA uses an air quality screening threshold to identify upwind states that contribute to downwind ozone concentrations in amounts sufficient to ''link'' them to these to downwind nonattainment and maintenance receptors. The contributions from each state to each downwind nonattainment or maintenance receptor that were used for the Step 2 evaluation can be found in the Air Quality Modeling Final Rule TSD.

The EPA applies an air quality screening threshold of 1 percent of the NAAQS, which has been used since the CSAPR rulemaking, including in the CSAPR Update, the Revised CSAPR Update, and numerous actions evaluating states' transport SIP submittals. The explanation for how this value was originally derived is available in the CSAPR rulemaking from 2011. *See* 76 FR 48208, 48237–38. As originally explained there, the application of a relatively low threshold is intended to capture a relatively large percentage of the contribution from upwind states to downwind receptors in light of the regional-scale, collective contribution problem associated with both ozone and $PM_{2.5}$ NAAQS. *Id.* The Agency also explained that the use of a higher threshold in transport rules prior to CSAPR was based on single-day maximum contribution, whereas in CSAPR (and continuing in subsequent rules including this one), the Agency uses a more robust, average contribution metric over multiple days. Thus, it was not the case that 1 percent of NAAQS was substantially more stringent than that prior approach. *Id.* at 48238. In the 2016 CSAPR Update, the EPA reviewed the 1 percent threshold (as coupled with multi-day averaging) and determined it was appropriate to continue to apply this threshold. The EPA compared the 1 percent threshold to a 0.5 percent of NAAQS threshold and a 5 percent of NAAQS threshold. The EPA found that the lower threshold did not capture appreciably more upwind state contribution compared to the 1 percent threshold, while the 5 percent threshold allowed too much upwind state contribution to drop out from further analysis.[174] The EPA continues to observe that nonattainment and maintenance receptors identified at Step 1 are impacted collectively by emissions from numerous upwind contributors. Therefore, application of a low, uniform screening threshold allows the EPA to identify upwind states that share a responsibility under the interstate transport provision to eliminate their significant contribution.

As we explained at proposal, the EPA recognizes that in 2018 it issued a memorandum indicating the potential for states to use a higher threshold at Step 2 in the development of their good neighbor SIP submissions where it could be technically justified. The August 2018 memorandum stated that ''it may be reasonable and appropriate'' for states to rely on an alternative 1 ppb threshold at Step 2.[175] (The memorandum also indicated that any

[174] *See* Final CSAPR Update Air Quality Modeling TSD, at 27–30 (EPA–HQ–OAR–2015–0596–0144). *See also* 86 FR 23054, 23085.

[175] August 2018 memo at 4.

higher alternative threshold, such as 2 ppb, would likely not be appropriate.) The EPA nonetheless proposed to fulfill its role under CAA section 110(c) in promulgating FIPs to directly implement good neighbor requirements, and in this role, proposed retaining use of the 1 percent threshold for all states. We noted that in several documents proposing transport SIP disapprovals, *see, e.g.,* 87 FR 9498 and 87 FR 9510 (Feb. 22, 2022), we explained that our experience since the issuance of the August 2018 memorandum regarding use of alternative thresholds led the Agency to believe it may not be appropriate to continue to attempt to recognize alternative contribution thresholds at Step 2, either in the context of SIPs or FIPs.

We went on to explain that the EPA's experience since 2018 is that allowing for alternative Step 2 thresholds may be impractical or otherwise inadvisable for a number of additional policy reasons. For a regional air pollutant such as ozone, consistency in requirements and expectations across all states is essential. Using multiple different thresholds at Step 2 with respect to the 2015 ozone NAAQS raises substantial policy consistency and practical implementation concerns.[176] The application of different thresholds at Step 2 has the potential to result in inconsistent determination of good neighbor obligations. From the perspective of ensuring effective regional implementation of good neighbor obligations, the more important analysis is the evaluation of the emissions reductions needed, if any, to address a state's significant contribution after consideration of a multifactor analysis at Step 3, including a detailed evaluation that considers air quality factors and cost. We explained that while alternative thresholds for purposes of Step 2 may be ''similar'' in terms of capturing the relative amount of upwind contribution (as described in the August 2018 memorandum), nonetheless, use of alternative thresholds would allow certain states to avoid further evaluation of potential emissions controls while other states must proceed to a Step 3 analysis. This could create significant equity and consistency problems among states.

The EPA further proposed that, in promulgating FIPs to address these obligations on a nationwide scale, national ozone transport policy would not be well-served by applying a single, less stringent threshold at Step 2. The EPA recognized in the August 2018 memo that there was some similarity in the amount of total upwind contribution captured (on a nationwide basis) between 1 percent and 1 ppb. However, the EPA noted at proposal that while this may be true in some sense, that is hardly a compelling basis to move to a 1 ppb threshold. Indeed, the 1 ppb threshold has the disadvantage of losing a certain amount of total upwind contribution for further evaluation at Step 3. Considering the core statutory objective of ensuring elimination of *all* significant contribution to nonattainment or interference of the NAAQS in downwind states and the broad, regional nature of the collective contribution problem with respect to ozone, EPA could not identify a compelling policy imperative to move to a 1 ppb threshold.

In the proposal, we also found consistency with past interstate transport actions such as CSAPR, and the CSAPR Update and Revised CSAPR Update rulemakings (which used a Step 2 threshold of 1 percent of the NAAQS for two less protective ozone NAAQS) to be an important consideration. Continuing to use a 1 percent of NAAQS approach ensures that as the NAAQS are revised and made more stringent, an appropriate increase in stringency at Step 2 occurs, so as to ensure an appropriately larger amount of total upwind-state contribution is captured for purposes of fully addressing interstate transport for the more protective NAAQS.

The Agency also questioned whether it would be a good use of limited resources to attempt to further justify the use of alternative thresholds for certain states at Step 2 for purposes of the 2015 ozone NAAQS. Therefore, while EPA articulated the possibility of an alternative threshold in the August 2018 memorandum, the EPA concluded in the proposal that our experience and further evaluation since the issuance of that memo has revealed substantial programmatic and policy difficulties in attempting to implement this approach, and therefore we proposed to apply the 1 percent of NAAQS threshold.

Comment: Many commenters disagreed with our proposal to continue using a 1 percent of NAAQS threshold. They argued that the EPA was reversing course from its policy as articulated in the August 2018 memorandum and that the EPA was now bound to use a 1 ppb threshold rather than 1 percent of NAAQS, even in promulgating a FIP rather than evaluating SIPs. Commenters further argued that a 1 ppb threshold would be more consistent with the EPA's ''significant impact level'' (SIL) guidance related to implementing prevention of significant deterioration (PSD) permitting requirements. They argued that the 1 percent threshold was below precision limits of regulatory ozone monitors, and they argued it was within the ''margin of error'' of the EPA's modeling.

Response: The EPA is finalizing its proposed approach of consistently using a 1 percent of the NAAQS threshold at Step 2 in this action to determine which states contribute to identified nonattainment and maintenance receptors. This approach ensures both national consistency across all states and consistency and continuity with our prior interstate transport actions for other NAAQS. We do not agree that this approach is inconsistent with or a reversal in policy from the August 2018 memorandum, which only suggested that states in the development of their SIPs ''may'' be able to establish that 1 ppb could be an appropriate alternative threshold. The EPA has been consistent in that memorandum, and since that time, that final determinations on alternative thresholds would be made through rulemaking action, as the EPA is taking here.

The August 2018 memorandum made clear that the Agency had substantial doubts that any threshold greater than 1 ppb (such as 2 ppb) would be acceptable, and the Agency is affirming that a threshold higher than 1 ppb would not be justified under any circumstance for purposes of this action. No commenter credibly provided a basis for using a threshold even higher than 1 ppb, and so this issue is primarily limited to the difference between a 0.7 ppb threshold (the 1 percent of the NAAQS threshold discussed previously in this section) and a 1.0 ppb threshold. Therefore, before proceeding in responding to these comments, we note that this issue is only relevant to a small number of states whose contributions to any receptor are above 1 percent of the NAAQS but lower than 1 ppb. Under the 2016v3 modeling of 2023 being used in this final rule, the states in this rule with contributions that fall between 0.70 ppb and 1 ppb are Alabama, Kentucky, and Minnesota. Similarly, the EPA applies the 1 percent threshold in its 2026 modeling projections to determine if any states will not be linked to an ozone receptor by that year, and therefore should not be subject to the more stringent requirements that take effect in 2026. The states in this rule in that year with contribution between 0.70 ppb and 1 ppb are

[176] We note that Congress has placed on the EPA a general obligation to ensure the requirements of the CAA are implemented consistently across states and regions. *See* CAA section 301(a)(2). Where the management and regulation of interstate pollution levels spanning many states is at stake, consistency in application of CAA requirements is paramount.

Kentucky, Nevada, and Oklahoma. For all other states covered in this action, at least one linkage exists in 2023 (and, as relevant, in 2026) that is greater than 1 ppb, and therefore the question of whether the EPA must recognize a 1 ppb threshold would not have a dispositive effect on the regulatory determination being made at Step 2.

The 1 percent of the NAAQS threshold is consistent with the Step 2 approach that the EPA applied in CSAPR for the 1997 ozone NAAQS and has subsequently been applied in the CSAPR Update and Revised CSAPR Update when evaluating determining interstate transport obligations for the 2008 ozone NAAQS. The EPA continues to find 1 percent of the ozone NAAQS to be an appropriate threshold. For ozone, as the EPA found in CAIR, CSAPR, and the CSAPR Update, a portion of the nonattainment and maintenance problems in the U.S. results from the combined impact of relatively small contributions from many upwind states, along with contributions from in-state sources and other sources. The EPA's analysis shows that the ozone transport problem being analyzed in this rule is still the result of the collective impacts of emissions from multiple upwind contributors. Therefore, application of a consistent contribution threshold is necessary to identify those upwind states that should have responsibility for addressing their contribution (to the extent found ''significant'' at Step 3) to the downwind nonattainment and maintenance problems to which they collectively contribute. Where a great number of geographically dispersed emissions sources contribute to a downwind air quality problem, which is the case for ozone, EPA believes that, in the context of CAA section 110(a)(2)(D)(i)(I), a state-level threshold of 1 percent of the NAAQS is a reasonably small enough value to identify only the greater-than-de minimis contributors yet is not so large that it unfairly focuses attention for further action only on the largest single or few upwind contributors. Continuing to use 1 percent of the NAAQS as the screening metric to evaluate collective contribution from many upwind states also allows the EPA (and states) to apply a consistent framework to evaluate interstate emissions transport under the interstate transport provision from one NAAQS to the next. *See* 86 FR 23054, 23085; 81 FR 74504, 74518; 76 FR 48208, 48237–38.

Further, the EPA notes that the role of the Step 2 threshold is limited and just one step in the larger 4-Step Framework. It serves to screen in states for further evaluation of emissions control opportunities applying a multifactor analysis at Step 3. Thus, as the Supreme Court has recognized, the contribution threshold essentially functions to exclude states with ''*de miminis*'' impacts. *EME Homer City,* 572 U.S. 489, 500.

Comments related to the August 2018 memorandum argued that the EPA legally committed itself to approving SIP submissions from states with contributions below 1 ppb and so now the EPA must apply that threshold in this FIP action. (Comments regarding this issue as related to the EPA's action on SIPs is addressed in that rulemaking and is beyond the scope of this action.) This is not what the memorandum said. The memorandum merely provided an analysis regarding ''the degree to which certain air quality threshold amounts capture the collective amount of upwind contribution from upwind states.'' [177] It interpreted ''that information to make recommendations about what thresholds *may* be appropriate for use in'' SIP submissions (emphasis added).[178] Specifically, the August 2018 memorandum said, ''Because the amount of upwind collective contribution capture with the 1 percent and the 1 ppb thresholds is *generally comparable, overall, we believe it may be* reasonable and appropriate for states to use a 1 ppb contribution threshold, as an alternative to a 1 percent threshold, at Step 2 of the 4-step framework in developing their SIP revisions addressing the good neighbor provision for the 2015 ozone NAAQS'' (emphasis added).[179] Thus, the text of the August 2018 memorandum in no way committed that the EPA would be using a 1 ppb threshold going forward either in its evaluation of SIPs or in promulgating a FIP. The August 2018 memorandum indicated that ''[f]ollowing these recommendations does not ensure that EPA will approve a SIP revision in all instances where the recommendations are followed, as the guidance may not apply to the facts and circumstances underlying a particular SIP. Final decisions by the EPA to approve a particular SIP revision will only be made based on the requirements of the statute and will only be made following an air agency's final submission of the SIP revision to the EPA, and after appropriate notice and opportunity for public review and comment.'' [180] Further, the August 2018 memorandum said that ''EPA and air agencies should consider whether the recommendations in this guidance are appropriate for each situation.'' [181] The memorandum said nothing regarding what threshold the EPA would apply if promulgating a FIP.

As explained in the SIP disapproval action and again here, the EPA finds it would not be sound policy to apply an alternative contribution threshold or thresholds to one or more states within the 4-step interstate transport framework for the 2015 ozone NAAQS. However, the EPA disagrees with commenters' claims that the agency has reversed course on applying the August 2018 memorandum, because the memorandum never adopted a view that the use of 1 ppb or other alternative thresholds would in fact be acceptable. Although the EPA said at proposal that the EPA may rescind the guidance in the future, we took comment on the subject and also stated, ''EPA is not at this time rescinding the August 2018 memorandum.'' [182] The EPA is not formally rescinding the August 2018 memorandum in this action or at this time. However, it is not required that agencies must ''rescind'' a memorandum or guidance the moment it becomes outdated or called into question. The August 2018 memorandum was not issued through notice-and-comment rulemaking and is not binding on the Agency or other parties. While the *willingness* of the Agency as expressed in that memorandum to entertain the possibility of an alternative threshold of 1 ppb may be considered a kind of policy position, agencies may change their non-binding policies without going through notice and comment rulemaking. *Catawba County* v. *EPA,* 571 F.3d 20, 34 (D.C. Cir. 2009). In this case, we went through notice and comment rulemaking on this topic in the SIP-disapproval action (88 FR 9336) and here, even though the August 2018 memorandum was issued without such opportunity for public input. We further address the basis for the consistent use of a 1 percent of NAAQS threshold and summarize our conclusions under the *FCC* v. *Fox* factors below.

We continue to believe, as set forth in our proposed action, that national ozone transport policy is not well served by

[177] August 2018 memorandum, at 1.

[178] *Id.*

[179] *Id.* at 4.

[180] *Id.* at 1.

[181] *Id.*

[182] 87 FR 9545, 9551 (Feb. 22, 2022) (Alabama, Mississippi, Tennessee); 87 FR 9498, 9510 (Feb. 22, 2022) (Kentucky); 87 FR 9838, 9844 (Feb. 22, 2022) (Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin); 87 FR 9798, 9807, 9813, 9820 (Feb. 22, 2022) (Arkansas, Louisiana, Oklahoma, Texas); 87 FR 9533, 9542 (Feb. 22, 2022) (Missouri); 87 FR 31470, 31479 (May 24, 2022) (Utah); 87 FR 31495, 31504 (May 24, 2022) (Wyoming); 87 FR 31485, 31490 (May 24, 2022) (Nevada).

allowing for less protective thresholds than 1 percent of the NAAQS at Step 2. Furthermore, the EPA disagrees with commenters who suggest that national consistency is an inappropriate consideration in the context of interstate ozone transport. The Good Neighbor provision, CAA section 110(a)(2)(D)(i)(I), requires to a unique degree of concern for consistency, parity, and equity across state lines.[183] For a regional air pollutant such as ozone, consistency in requirements and expectations across all states is essential. Based on the EPA's review of good neighbor SIP submissions to-date and after further consideration of the policy implications of attempting to recognize an alternative Step 2 threshold for certain states, the Agency concludes that the attempted use of different thresholds at Step 2 with respect to the 2015 8-hour ozone NAAQS raises substantial policy consistency and practical implementation concerns. The availability of different thresholds at Step 2 has the potential to result in inconsistent application of good neighbor obligations based solely on the strength of a state's SIP submission at Step 2 of the 4-step interstate transport framework. The steps of the analysis that lead up to evaluating emissions reductions opportunities to address states' significant contribution at Step 3 should be applied on a consistent basis. Where alternative thresholds for purposes of Step 2 may be ''similar'' in terms of capturing the relative amount of upwind contribution (as described in the August 2018 memorandum), nonetheless, use of an alternative threshold would allow certain states to avoid further evaluation of potential emissions controls while other states must proceed to a Step 3 analysis. This can create significant equity and consistency problems among states and could lead to ineffective or inefficient approaches to eliminating significant contribution.

One commenter suggested the EPA could address this potentially inequitable outcome by simply adopting a 1 ppb contribution threshold for all states. However, the August 2018 memorandum did not conclude that 1 ppb would be appropriate for all states and the EPA does not view that conclusion to be supported at present. The EPA recognized in the August 2018 memorandum that there was some similarity in the amount of total upwind contribution captured (on a nationwide basis) between 1 percent and 1 ppb. However, while this may be true in some sense, that is hardly a compelling basis to move to a 1 ppb threshold for every state. Indeed, the 1 ppb threshold has the disadvantage of losing a certain amount of total upwind contribution for further evaluation at Step 3 (*e.g.,* roughly 7 percent of total upwind state contribution was lost according to the modeling underlying the August 2018 memorandum; in the EPA's 2016v2 modeling, the amount lost is 5 percent; in the EPA's 2016v3 modeling used for final, the amount lost is also 5 percent). Further, this logic has no end point. A similar observation could be made with respect to any incremental change. For example, should the EPA next recognize a 1.2 ppb threshold because that would only cause some small additional loss in capture of upwind state contribution as compared to 1 ppb? If the only basis for moving to a 1 ppb threshold is that it captures a ''similar'' (but actually smaller) amount of upwind contribution, then there is no basis for moving to that threshold at all. Considering the core statutory objective of ensuring elimination of all significant contribution to nonattainment or interference with maintenance of the NAAQS in other states and the broad, regional nature of the collective contribution problem with respect to ozone, we continue to find no compelling policy reason to adopt a new threshold for all states of 1 ppb.

Nor have commenters explained why use of a 1 ppb threshold would be appropriate under the more protective 2015 ozone NAAQS when a 1 percent of the NAAQS contribution threshold has been used for less protective ozone NAAQS. To illustrate, a state contributing greater than 0.75 ppb but less than 1 ppb to a receptor under the 2008 ozone NAAQS was ''linked'' at Step 2,[184] but if a 1 ppb threshold were used for the 2015 ozone NAAQS then that same state would *not* be ''linked'' to a receptor at Step 2 under a NAAQS that is set to be *more* protective of human health and the environment. Consistency with past interstate transport actions such as CSAPR, and the CSAPR Update and Revised CSAPR Update rulemakings (which all used the 1 percent of the NAAQS for less protective ozone NAAQS), is an important consideration. We affirm our view in CSAPR that continuing to use a 1 percent of NAAQS approach ensures that if the NAAQS are revised and made more stringent, an appropriate increase in stringency at Step 2 occurs, so as to ensure an appropriately larger amount of total upwind-state contribution is captured for purposes of fully addressing interstate transport. *See* 76 FR 48208, 48237–38.

We note further that application of a 1 percent of NAAQS threshold has been the EPA's consistent approach in each of our notice-and-comment rulemakings beginning with CSAPR and continuing with the CSAPR Update, the Revised CSAPR Update, and numerous actions on ozone transport SIP submissions. In each case, the 1 percent of the NAAQS threshold was subject to rigorous vetting through public comment and the Agency's response to those comments, including through the use of analytical evaluations of alternative thresholds. *See, e.g.,* 81 FR 74518–19. By contrast, the August 2018 memorandum was not issued through notice-and-comment rulemaking procedures, and the EPA was careful to caveat its utility and ultimate reliability for that reason.

The EPA disagrees with claims that the EPA is applying the August 2018 memorandum inconsistently based on the EPA's actions with regard to Arizona, Iowa, and Oregon. The EPA withdrew a previously proposed approval of Iowa's SIP submission that was premised on a 1 ppb contribution threshold, and re-proposed and finalized approval of that SIP based on a different rationale using a 1 percent of the NAAQS contribution threshold. 87 FR 9477 (Feb. 22, 2022); 87 FR 22463 (April 15, 2022). The EPA also disagrees with any claim that Oregon and Arizona were ''allowed'' to use a 1 ppb or higher threshold. The EPA approved Oregon's SIP submission for the 2015 ozone NAAQS on May 17, 2019, and both Oregon and the EPA relied on a 1 percent of the NAAQS contribution threshold. 84 FR 7854, 7856 (March 5, 2019) (proposal); 84 FR 22376 (May 17, 2019) (final). In the proposal for this action, the EPA explained it was not proposing to conduct an error correction for Oregon even though updated modeling indicated Oregon contributed above 1 percent of the NAAQS to monitors in California.

The EPA is deferring finalizing a finding at this time for Oregon (*see* section IV.G of this document for additional information). In 2016, the EPA approved Arizona's SIP for the earlier 2008 ozone NAAQS based on a similar rationale with regard to certain monitors in California. 81 FR 15200 (March 22, 2016) (proposal); 81 FR 31513 (May 19, 2016) (final rule). We are deferring finalizing a finding at this time that such a rationale is appropriate

[183] EPA notes that Congress has placed on EPA a general obligation to ensure the requirements of the CAA are implemented consistently across states and regions. *See* CAA section 301(a)(2). Where the management and regulation of interstate pollution levels spanning many states is at stake, consistency in application of CAA requirements is paramount.

[184] *See* 86 FR 23054, 23058 (April 30, 2021).

with respect to the more protective 2015 ozone NAAQS. While Arizona and Oregon's interstate transport obligations for the 2015 ozone NAAQS remain pending (along with several other states), there is no inconsistency in the treatment of these states or any other state at Step 2.

Some commenters claim the EPA must use a 1 ppb threshold based on the identification of 1 ppb as a significance threshold in one step of the PSD permitting process. The EPA's SIL guidances, however, relate to a different provision of the Clean Air Act regarding implementation of the prevention of significant deterioration (PSD) permitting program. This program applies in areas that have been designated attainment of the NAAQS and is intended to ensure that such areas remain in attainment even if emissions were to increase as a result of new sources or major modifications to existing sources located in those areas. This purpose is different than the purpose of the good neighbor provision, which is to assist downwind areas (in some cases hundreds or thousands of miles away) in resolving ongoing nonattainment of the NAAQS or difficulty maintaining the NAAQS through eliminating the emissions from other states that are significantly contributing to those problems. In addition, as discussed in preceding paragraphs, the purpose of the Step 2 threshold within the EPA's interstate transport framework for ozone is to broadly sweep in all states contributing to identified receptors above a de minimis level in recognition of the collective-contribution problem associated with regional-scale ozone transport. The threshold used in the context of PSD SIL serves a different purpose, and so it does not follow that they should be made equivalent. Further, commenters incorrectly associate the EPA's Step 2 contribution threshold with the identification of ''significant'' emissions (which does not occur until Step 3), and so it is not the case that the EPA is interpreting the same term differently.

The EPA has previously explained this distinction between the good neighbor framework and PSD SILs. *See* 70 FR 25162, 25190–25191 (May 12, 2005); 76 FR 48208, 48237 (Aug. 8, 2011). Importantly, the implication of the PSD SIL threshold is not that single-source contribution below this level indicates the absence of a contribution or that no emissions control requirements are warranted. Rather, the PSD SIL threshold addresses whether further, more comprehensive, multi-source review or analysis of air quality impacts are required of the source to support a demonstration that it meets the criteria for a permit. A source with estimated impacts below the PSD SIL may use this to demonstrate that it will not cause or contribute (as those terms are used within the PSD program) to a violation of an ambient air quality standard, but is still subject to meeting applicable control requirements, including best available control technology, designed to moderate the source's impact on air quality.

Moreover, other aspects of the technical methodology in the SILs guidance compared to the good neighbor framework make a direct comparison between these two values misleading. For instance, in PSD permit modeling using a single year of meteorology the maximum single-day 8-hour contribution is evaluated with respect to the SIL. The purpose of the contribution threshold at Step 2 of the 4-step good neighbor framework is to determine whether the average contribution from a collection of sources in a state is small enough not to warrant any additional control for the purpose of mitigating interstate transport, even if that control were highly cost effective. Using a 1 percent of the NAAQS threshold is more appropriate for evaluating multi-day average contributions from upwind states than a 1 ppb threshold applied for a single day, since that lower value of 1 percent of the NAAQS will capture variations in contribution. If EPA were to use a single day reflecting the maximum amount of contribution from an upwind state to determine whether a linkage exists at Step 2, commenters' arguments for use of the PSD SIL might have more force. This would in effect be a return to the pre-CSAPR contribution calculation methodology of using a single day, *see* 76 FR 48238. However, that would likely cause more states to become linked, not less. And in any case, consistent with the method in our modeling guidance for projecting future attainment/nonattainment and as the EPA concluded in 2011 in CSAPR, the present good neighbor methodology of using multiple days provides a more robust approach to establishing that a linkage exists at the state level than relying on a single day of data.

A commenter also claimed the 1 percent of NAAQS threshold is inconsistent with the standards of precision for Federal reference monitors for ozone and the rounding requirements found in 40 CFR part 50, appendix U, Interpretation of the Primary and Secondary National Ambient Air Quality Standards for Ozone. Commenter claimed that the 1 percent contribution threshold of 0.7 ppb is lower than the manufacturer's reported precision of these reference monitors and that the requirements found in Appendix U truncates monitor values of 0.7 ppb to 0 ppb. However, the commenter is mistaken in applying criteria related to the precision of monitoring technology to the modeling methodology by which we project contributions when quantifying and evaluating interstate transport at Step 2. Indeed, contributions by source or state cannot be derived from the total ambient concentration of ozone at a monitor at all but must be apportioned through modeling. Under our longstanding methodology for doing so, the contribution values identified from upwind states are based on a robust assessment of the average impact of each upwind state's ozone-precursor emissions over a range of scenarios, as explained in the 2016v3 modeling's Air Quality Modeling Final Rule TSD, in the docket for this rule, Docket ID No. EPA–HQ–OAR–2021–0668. This analysis is in no way connected with or dependent on monitoring instruments' precision of measurement. *See EME Homer City,* 795 F.3d 118, 135–36 (''[A] model is meant to simplify reality in order to make it tractable.' '') (quoting *Chemical Manufacturers Association* v. *EPA,* 28 F.3d 1259, 1264 (D.C. Cir. 1994).

To the extent that commenters argue that the EPA consider a less stringent threshold as a result of modeling uncertainty, the EPA disagrees with this notion. The EPA has successfully applied a 1 percent of NAAQS threshold to identify linked upwind states using modeling in three prior FIP rulemakings and numerous state-specific actions on good neighbor obligations. This continues to be a reasonable approach, and indeed courts have repeatedly declined to establish bright line criteria for model performance. In upholding the EPA's approach to evaluating interstate transport in CSAPR, the D.C. Circuit held that it would not ''invalidate EPA's predictions solely because there might be discrepancies between those predictions and the real world. That possibility is inherent in the enterprise of prediction.'' *EME Homer City Generation, L.P.* v. *EPA,* 795 F.3d 118, 135 (2015). ''[T]he fact that a 'model does not fit every application perfectly is no criticism; a model is meant to simplify reality in order to make it tractable.' '' *Id.* at 135–36 (quoting *Chemical Manufacturers Association* v. *EPA,* 28 F.3d 1259, 1264 (D.C. Cir. 1994). *See also Sierra Club* v. *EPA,* 939 F.3d 649, 686–87 (5th Cir. 2019) (upholding EPA's modeling in the face of complaints regarding an alleged ''margin of error,'' noting challengers face a ''considerable burden'' in overcoming a ''presumption of regularity'' afforded ''the EPA's choice of analytical methodology'') (citing *BCCA Appeal Grp.* v. *EPA,* 355 F.3d 817, 832 (5th Cir. 2003)).

The Agency will continue to use the CAMx model to evaluate contributions from upwind states to downwind areas. The agency has used CAMx routinely in previous notice and comment transport rulemakings to evaluate contributions relative to the 1 percent threshold for both ozone and $PM_{2.5}$. In fact, in the original CSAPR, the EPA found that ''[t]here was wide support from commenters for the use of CAMx as an appropriate, state-of-the science air quality tool for use in the [Cross-State Air Pollution] Rule. There were no comments that suggested that the EPA should use an alternative model for quantifying interstate transport.'' 76 FR 48229 (August 8, 2011). In this action, the EPA has taken a number of steps based on comments and new information to ensure to the greatest extent the accuracy and reliability of its modeling projections at Step 1 and 2, as discussed elsewhere in this section.

The EPA disagrees with commenters that case law reviewing changes in agency positions such as *FCC* v. *Fox TV Stations, Inc.,* 556 U.S. 502, 515 (2009), is applicable with respect to this issue. As explained above, under the terms of the August 2018 memorandum, the Agency did not conclude that the use of an alternative contribution threshold was justified for any states. But even if it were found that the Agency's position had changed between this rulemaking action and the August 2018 memorandum, the *FCC* v. *Fox* factors are met. We have explained above that there are good reasons for continuing to use a 1 percent of NAAQS threshold. We also are aware that we are not using a 1 ppb threshold despite acknowledging the potential for doing so in the August 2018 memorandum. We do not believe that any party has a serious reliance interest that would be sufficient to overcome the countervailing public interest that is served through the EPA's determination to maintain continuity with its longstanding, more protective 1 percent of NAAQS threshold in this action. *Cf.* 88 FR 9373 (reviewing reliance in the context of the SIP-disapproval action).

The EPA therefore will continue its longstanding practice of applying the 1 percent of NAAQS threshold in this action.

a. States That Contribute Below the Screening Threshold

Based on the EPA's modeling and considering measured data at violating monitors, the contributions from each of the following states to nonattainment or maintenance-only receptors in the 2023 analytic year are below the 1 percent of the NAAQS threshold: Colorado, Connecticut, the District of Columbia, Delaware, Florida, Georgia, Idaho, Maine, Massachusetts, Montana, Nebraska, New Hampshire, North Carolina, North Dakota, Rhode Island, South Carolina, South Dakota, Vermont, and Washington.[185] The EPA has already approved these states' 2015 ozone good neighbor SIP submittals. Because the contributions from these states to projected downwind air quality problems are below the screening threshold in the current modeling, these states are not within the scope of this final rule. Additionally, the EPA has made final determinations that two states outside the modeling domain for the air quality modeling analyzed in this final rulemaking—Hawaii[186] and Alaska[187]—do not significantly contribute to nonattainment or interfere with maintenance of the NAAQS in any other state.

With respect to Wyoming, our methodology when applied using the 2016v3 modeling suggests that whether the state is linked is uncertain and warrants further analysis. The EPA intends to expeditiously review its assessment with respect to Wyoming and take action addressing Wyoming's good neighbor obligations for the 2015 ozone NAAQS through a separate action.

b. States That Contribute at or Above the Screening Threshold

Based on the maximum downwind contributions in Table IV.F–1, the Step 2 analysis identifies that the following 21 states contribute at or above the 0.70 ppb threshold to downwind nonattainment receptors in 2023: Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. Based on the maximum downwind contributions in Table IV.F–1, the following 23 states contribute at or above the 0.70 ppb threshold to downwind modeling-based maintenance-only receptors in 2023: Arizona, Arkansas, California, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New Mexico, New York, Ohio, Oklahoma, Texas, Virginia, West Virginia, and Wisconsin. Based on the maximum downwind contribution in Table IV.F–3, the following additional states contribute at or above the 0.70 ppb threshold to downwind violating monitor maintenance-only receptors in 2023: Kansas and Tennessee. (However, the EPA is not taking final action based on this analytical result for these two states at this time.) The levels of contribution between each of these linked upwind states and downwind nonattainment receptors and maintenance-only receptors are provided in the Air Quality Modeling Final Rule TSD.

Among the linked states are several western states—California, Nevada, and Utah. While the EPA has not previously included action on linked western states in its prior CSAPR rulemakings, the EPA has consistently applied the 4-step framework in evaluating good neighbor obligations from these states. On a case-by-case basis, the EPA has found in some instances with respect to the 2008 ozone NAAQS that a unique consideration has warranted approval of a western state's good neighbor SIP submittal that might otherwise be found to contribute above 1 percent of the NAAQS without concluding that additional emissions reductions are required at Step 3 of the framework.[188] The EPA has also explained in prior actions that its air quality modeling is reliable for assessing downwind air quality problems and ozone transport contributions from upwind states throughout the nationwide modeling domain.[189] The EPA is deferring finalizing a finding at this time for Oregon (*see* section IV.G of this document for additional information).

As explained in the following section, the EPA is not, in this action, altering its prior approval of Oregon's good neighbor SIP submission for the 2015 ozone NAAQS. For the remaining western states included in this rule, the EPA's modeling supports a conclusion that these states are linked above the

[185] The status of monitoring sites in California to which Oregon may be linked is under review. *See* section IV.G.

[186] The EPA approved Hawaii's 2015 ozone transport SIP on December 27, 2021. *See* 86 FR 73129.

[187] The EPA approved Alaska's 2015 ozone transport SIP on December 18, 2019. *See* 84 FR 69331.

[188] *See* interstate transport approval actions under the 2008 ozone NAAQS for Arizona, California, and Wyoming at 81 FR 36179 (June 6, 2016), 83 FR 65093 (December 19, 2018), and 84 FR 14270 (April 10, 2019)), respectively.

[189] *See* 81 FR 71991 (October 19, 2016), 82 FR 9155 (February 3, 2017).

contribution threshold to identified ozone transport receptors in downwind states, and therefore, consistent with the treatment of all other states within the modeling domain, the EPA proposes to proceed to evaluate these states for a determination of ''significant contribution'' at Step 3.

In conclusion, as described above, states with contributions that equal or exceed 1 percent of the NAAQS to either nonattainment or maintenance-only receptors are identified as ''linked'' at Step 2 of the good neighbor framework and warrant further analysis for significant contribution to nonattainment or interference with maintenance under Step 3. The EPA finds that for purposes of this final rule, the following 23 states are linked at Step 2 in 2023: Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin. In addition, the EPA finds that the following 20 States are linked at Step 2 in 2026: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. We note that our updated modeling for this final rule shows that two states, Minnesota and Wisconsin, that we found linked in 2026 at proposal are no longer projected to be linked in that year but are linked in 2023.[190] As at proposal, Alabama is only projected to be linked in 2023, not 2026.

For six states, the EPA's analysis at this time indicates that a linkage may exist in 2023 for which the EPA had not proposed FIP requirements, or the updated analysis for this final rule suggests that linkages we had previously found in the proposed action are now uncertain and warrant further analysis. The EPA intends to expeditiously address these states in a separate action or actions: Arizona, Iowa, Kansas, New Mexico, Tennessee, and Wyoming.

G. Treatment of Certain Monitoring Sites in California and Implications for Oregon's Good Neighbor Obligations for the 2015 Ozone NAAQS

The EPA previously approved Oregon's September 25, 2018 transport SIP submittal for the 2015 ozone NAAQS on May 17, 2019 (84 FR 22376), because in an earlier round of modeling Oregon was not projected to contribute above 1 percent of the NAAQS to any downwind receptors. In the EPA's updated modeling used at proposal (2016v2) and again in the final modeling (2016v3), Oregon is modeled to contribute above the 1 percent of NAAQS threshold to several monitoring sites in California that would generally meet the EPA's definition of nonattainment or maintenance ''receptors'' at Step 1.[191] At proposal, the EPA explained that our analysis of the nature of the air quality problem at these monitoring sites led us to propose a determination that these monitoring sites should not be treated as receptors for purposes of determining interstate transport obligations of upwind states under CAA section 110(a)(2)(D)(i)(I). We explained that we reached this conclusion at Step 1 of our 4-step framework.

The EPA previously made a similar assessment of the nature of certain other monitoring sites in California in approving Arizona's 2008 ozone NAAQS transport SIP submittal.[192] There, the EPA noted that a ''factor [. . .] relevant to determining the nature of a projected receptor's interstate transport problem is the magnitude of ozone attributable to transport from all upwind states collectively contributing to the air quality problem.'' [193] The EPA observed that only one upwind state (Arizona) was linked above 1 percent of the 2008 ozone NAAQS to the two relevant monitoring sites in California, and the cumulative ozone contribution from all upwind states to those sites was 2.5 percent and 4.4 percent of the total ozone, respectively. The EPA determined the size of those cumulative upwind contributions was ''negligible, particularly when compared to the relatively large contributions from upwind states in the East or in certain other areas of the West.'' [194] In that action, the EPA concluded the two California sites to which Arizona was linked should not be treated as receptors for the purposes of determining Good Neighbor obligations for the 2008 ozone NAAQS.[195]

Comment: Commenters criticized what they considered to be unfair treatment of Oregon, stating that the EPA is applying a higher contribution threshold than it applies to other states. Commenters argued that EPA has not established a specific threshold for why the level of upwind-state impact at these sites should not be considered meaningful. Commenters argued that our analysis ignored the fact that there are many monitoring sites in California to which Oregon contributes above 1 percent of the NAAQS. Commenters state that EPA has failed to explain why Oregon is not subject to this rulemaking, while other states contribute lower total downwind ozone contributions and fewer receptors. Commenters concluded that since Oregon is linked it should be subject to the same emissions control determinations at Step 3 and 4 as every other state, or otherwise apply the same ''nature of the air quality problem'' consideration to eliminate other receptors.

Response: The EPA acknowledges that several commenters opposed the proposed treatment of Oregon and the California monitoring sites to which it is linked in the proposed and final modeling. We also recognize that other commenters expressed confusion regarding the role of this proposed determination at Step 1 and how it relates to the longstanding 4-step interstate transport framework that the EPA is otherwise applying in this action. In recognition of these concerns and the need to give further thought to the appropriate treatment of both upwind states and downwind receptors in these circumstances, the EPA is deferring finalizing a finding at this time for Oregon. The current approval of the state's SIP submission will remain in place for the time being, pending further review. We make no final determination in this action regarding whether the California monitoring sites at issue should or should not be treated as receptors for purposes of addressing interstate transport for the 2015 ozone NAAQS.

V. Quantifying Upwind-State NO_X Emissions Reduction Potential To Reduce Interstate Ozone Transport for the 2015 Ozone NAAQS

A. The Multi-Factor Test for Determining Significant Contribution

This section describes the EPA's methodology at Step 3 of the 4-step framework for identifying upwind emissions that constitute ''significant'' contribution for the states subject to this final rule and focuses on the 23 states with FIP requirements identified in the

[190] Minnesota and Wisconsin were linked to maintenance-only receptors in Cook County, IL in 2023. Minnesota and Wisconsin are not linked in 2026 because the 2026 average and maximum design values at the monitoring sites are projected to show attainment.

[191] Monitors are included in the docket for this rulemaking. While EPA is providing information about cumulative upwind contribution to the California monitors, the Agency is not making a determination in this action that these monitors are ozone transport receptors.

[192] 81 FR 15200 (March 22, 2016) (proposal); 81 FR 31513 (May 19, 2016) (final rule).

[193] 81 FR 15203.

[194] *Id.*

[195] *Id.*

previous sections. Following the existing framework as applied in the prior CSAPR rulemakings, the EPA's assessment of linked upwind state emissions is based primarily on analysis of several alternative levels of NO_X emissions control stringency applied uniformly across all of the linked states. The analysis includes assessment of non-EGU stationary sources in addition to EGU sources in the linked upwind states.

The EPA applies a multi-factor test—the same multi-factor test that was used in CSAPR, the CSAPR Update, and the Revised CSAPR Update [196]—to evaluate increasing levels of uniform NO_X control stringency. The multi-factor test, which is central to EPA's Step 3 quantification of significant contribution, considers cost, available emissions reductions, downwind air quality impacts, and other factors to determine the appropriate level of uniform NO_X control stringency that would eliminate significant contribution to downwind nonattainment or maintenance receptors. The selection of a uniform level of NO_X emissions control stringency across all of the linked states, reflected as a representative cost per ton of emissions reduction (or a weighted average cost per ton in the case of EPA's non-EGU and EGU analysis for 2026 mitigation measures), also serves to apportion the reduction responsibility among collectively contributing upwind states. This approach to quantifying upwind state emission-reduction obligations using uniform cost was reviewed by the Supreme Court in *EME Homer City Generation,* which held that using such an approach to apportion emissions reduction responsibilities among upwind states that are collectively responsible for downwind air quality impacts ''is an efficient and equitable solution to the allocation problem the Good Neighbor Provision requires the Agency to address.'' 572 U.S. at 519.

There are four stages in developing the multi-factor test: (1) identify levels of uniform NO_X control stringency; (2) evaluate potential NO_X emissions reductions associated with each identified level of uniform control stringency; (3) assess air quality improvements at downwind receptors for each level of uniform control stringency; and (4) select a level of control stringency considering the identified cost, available NO_X emissions reductions, and downwind air quality impacts, while also ensuring that emissions reductions do not unnecessarily over-control relative to the contribution threshold or downwind air quality.

As mentioned in section III.A.2 of this document, commenters on the proposed rule and previous ozone transport rules have suggested that the EPA should regulate VOCs as an ozone precursor. For this final rule, the EPA examined the results of the contribution modeling performed for this rule to identify the portion of the ozone contribution attributable to anthropogenic NO_X emissions versus VOC emissions from each linked upwind state to each downwind receptor. Of the total upwind-downwind linkages in 2023, the contributions from NO_X emissions comprise 80 percent or more of the total anthropogenic contribution for nearly all of the linkages (121 out of 124 total). Across all receptors, the contribution from NO_X emissions ranges from 84 percent to 97 percent of the total anthropogenic contribution from upwind states. This review of the portion of the ozone contribution attributable to anthropogenic NO_X emissions versus VOC emissions from each linked upwind state leads the Agency to conclude that the vast majority of the downwind air quality areas addressed by the final rule under are primarily NO_X-limited, rather than VOC-limited. Therefore, the EPA continues to find that regulation of VOCs as an ozone precursor in upwind states is not necessary to eliminate significant contribution or interference with maintenance in downwind areas in this final rule. The remainder of this section focuses on EPA's strategy for reducing regional-scale transport of ozone by targeting NO_X emissions from stationary sources to achieve the most effective reductions of ozone transport over the geography of the affected downwind areas.

For both EGUs and non-EGUs, section V.B of this document describes the available NO_X emissions controls that the EPA evaluated for this final rule and their representative cost levels (in 2016$). Section V.C of this document discusses EPA's application of that information to assess emissions reduction potential of the identified control stringencies. Finally, section V.D of this document describes EPA's assessment of associated air quality impacts and EPA's subsequent identification of appropriate control stringencies considering the key relevant factors (cost, available emissions reductions, and downwind air quality impacts).

This multi-factor approach is consistent with EPA's approach in prior transport actions, such as CSAPR. In addition, as was evaluated in the CSAPR Update and Revised CSAPR Update, the EPA evaluated whether, based on particularized evidence, its selected control strategy would result in over-control for any upwind state by examining whether an upwind state is linked solely to downwind air quality problems that could have been resolved at a lesser threshold of control stringency and whether an upwind state could reduce its emissions below the 1 percent air quality contribution threshold at a lesser threshold of control stringency. This analysis is described in section V.D of this document.

Finally, while the EPA has evaluated potential emissions reductions from non-EGU sources in prior rules and found certain non-EGU emissions reductions should inform the budgets established in the NO_X SIP Call, this is the first action for which the EPA is finalizing non-EGU emissions reductions within the context of the specific, 4-step interstate transport framework established in CSAPR. The EPA applies its multi-factor test to non-EGUs and independently evaluates non-EGU industries in a consistent but parallel track to its Step 3 assessment for EGUs. This is consistent with the parallel assessment approach taken for EGUs and non-EGUs in the Revised CSAPR Update. Following the conclusions of the EGU and non-EGU multi-factor tests, the identified reductions for EGUs and non-EGUs are combined and collectively analyzed to assess their effects on downwind air quality and whether the rule achieves a full remedy to eliminate ''significant contribution'' while avoiding over-control.

To ensure that this rule implements a full remedy for the elimination of significant contribution from upwind states, the EPA has reviewed available information on all major industrial source sectors in the upwind states inclusive of commenter-provided data. This analysis leads the EPA to conclude that both EGUs and certain large sources in several specific industrial categories should be evaluated for emissions control opportunities. As discussed in the sections that follow, the EPA determines, for both EGUs and the selected non-EGU source categories, there are impactful emissions reduction opportunities available at reasonable cost-effectiveness thresholds. As in the Revised CSAPR Update, the EPA examines EGUs and non-EGUs in this section on consistent but distinct parallel tracks due to differences stemming from the unique characteristics of the power sector

[196] *See* CSAPR, Final Rule, 76 FR 48208 (August 8, 2011).

compared to other industrial source categories.

Since the NO_X SIP Call, EGUs have consistently been regulated under ozone transport rules. These units operate in a coordinated manner across a highly interconnected electrical grid. Their configuration and emissions control strategies are relatively homogenous, and their emissions levels and emissions control opportunities are generally very well understood due to longstanding monitoring and data-reporting requirements. Non-EGU sources, by contrast, are relatively heterogeneous, even within a single industrial category, and have far greater variation in existing emissions control requirements, emissions levels, and technologies to reduce emissions. In general, despite these differences, the information available for this rulemaking indicates that both EGUs and certain non-EGU categories have available cost-effective NO_X emissions reduction opportunities at relatively commensurate cost per ton levels, and these emissions reductions will make a meaningful improvement in air quality at the downwind receptors. Section V.B.2 of this document describes EPA's process for selecting specific non-EGU industries and emissions unit types included in this final rulemaking.

The EPA notes that its Step 3 analysis for this FIP does not assess additional emissions reduction opportunities from mobile sources. The EPA continues to believe that title II of the CAA provides the primary authority and process for reducing these emissions at the Federal level. EPA's various Federal mobile source programs, summarized in this section, have delivered and are projected to continue to deliver substantial nationwide reductions in both VOCs and NO_X emissions; these reductions from final rules are factored into the Agency's assessment of air quality and contributions at Steps 1 and 2. Further, states are generally preempted from regulating new vehicles and engines with certain exceptions, and therefore a question exists regarding EPA's authority to address such emissions through such means when regulating in place of the states under CAA section 110(c). *See generally* CAA section 209. *See also* 86 FR 23099. As noted earlier, the EPA accounted for mobile source emissions reductions resulting from other federally enforceable regulatory programs in the development of emissions inventories used to support analysis for this final rulemaking, and the EPA does not evaluate any mobile source control measures in its Step 3 evaluation in this rule.[197] For further discussion of EPA's existing and ongoing mobile source measures, *see* section V.B.4 of this document.

B. Identifying Control Stringency Levels

1. EGU NO_X Mitigation Strategies

In identifying levels of uniform control stringency for EGUs, the EPA assessed the same NO_X emissions controls that the Agency analyzed in the CSAPR Update and the Revised CSAPR Update, all of which are considered to be widely available in this sector: (1) fully operating existing SCR, including both optimizing NO_X removal by existing operational SCRs and turning on and optimizing existing idled SCRs; (2) installing state-of-the-art NO_X combustion controls; (3) fully operating existing SNCRs, including both optimizing NO_X removal by existing operational SNCRs and turning on and optimizing existing idled SNCRs; (4) installing new SNCRs; and (5) installing new SCRs. Finally, for each of these combustion and post combustion technologies identified, EPA evaluated whether emissions reduction potential from generation shifting at that representative dollar per ton level was appropriate at this Step. Shifting generation to lower NO_X emitting or zero-emitting EGUs may occur in response to economic factors. As the cost of emitting NO_X increases, it becomes increasingly cost-effective for units with lower NO_X rates to increase generation, while units with higher NO_X rates reduce generation. Because the cost of generation is unit-specific, this generation shifting occurs incrementally on a continuum. For the reasons explained in the following sections and supported by technical information provided in the EGU NO_X Mitigation Strategies Final Rule TSD included in the docket for this final rule, the EPA determined that for the regional, multi-state scale of this rulemaking, only EGU NO_X emissions controls 1 and 3 are possible for the 2023 ozone season (fully operating existing SCRs and SNCRs). The EPA finds that it is not possible to install state-of-the-art NO_X combustion controls by the 2023 ozone season on a regional scale; those controls are assumed to be available by the beginning of the 2024 ozone season. All cost values discussed in the rest of the section for EGUs are in 2016 dollars.

a. Optimizing Existing SCRs

Optimizing (*i.e.,* turning on idled or improving operation of partially operating) existing SCRs can substantially reduce EGU NO_X emissions quickly, using investments that have already been made in pollution control technologies. With the promulgation of the CSAPR Update and the Revised CSAPR Update, most operators in the covered states improved their SCR performance and have continued to maintain that level of improved operation. However, this optimized SCR performance was not universal and not always sustained. Between 2017 and 2020, as the CSAPR Update ozone-season NO_X allowance price declined, NO_X emissions rates at some SCR-controlled EGUs increased. For example, power sector data from 2019 revealed that, in some cases, operating units had SCR controls that had been idled or were operating partially, and therefore suggested that there remained emissions reduction potential through optimization.[198] The EPA determined in the Revised CSAPR Update that optimizing SCRs was a readily available approach for EGUs to reduce NO_X emissions in the 12 states addressed by a FIP in that rulemaking. Noticeable improvements in emissions rates at units with SCRs during the 2021 and 2022 compliance period further affirm the ability of sources to quickly implement this mitigation strategy and to realize emissions reductions from doing so. This emissions reduction measure is currently available at EGUs across the broader geography affected in this final rulemaking (including in states not previously affected by the Revised CSAPR Update). The EPA thus determines that SCR optimization, of both idled and partially operating controls, is a viable mitigation strategy for the 2023 ozone season.

The EPA estimates a representative marginal cost of optimizing SCR controls to be approximately $1,600 per ton, consistent with its estimation in the Revised CSAPR Update for this technology. EPA's EGU NO_X Mitigation Strategies Final Rule TSD for this rule describes a range of cost estimates for

[197] The EPA recognizes that mechanisms exist under title I of the CAA that allow for the regulation of the use and operation of mobile sources to reduce ozone-precursor emissions. These include specific requirements that apply in certain ozone nonattainment areas including motor vehicle inspection and maintenance (I/M) programs, gasoline vapor recovery, clean-fuel vehicle programs, transportation control programs, and vehicle miles traveled programs. *See, e.g.,* CAA sections 182(b)(3), 182(b)(4), 182(c)(3), 182(c)(4), 182(c)(5), 182(d)(1), 182(e)(3), and 182(e)(4). The EPA views these programs as well as others that meet CAA requirements can be effective and appropriate in the context of the planning requirements applicable to designated nonattainment areas.

[198] *See* ''Ozone Season Data 2018 vs. 2019'' and ''Coal-fired Characteristics and Controls'' at *https://www.epa.gov/airmarkets/power-plant-data-highlights#OzoneSeason*.

this technology noting that the costs are frequently lower than—and for the majority of EGUs, significantly lower than—this representative marginal cost. While the costs of optimizing existing, operational SCRs include only variable costs, the cost of optimizing SCR units that are currently idled considers both variable and fixed costs of returning the control into service. Variable and fixed costs include labor, maintenance and repair, parasitic load, and ammonia or urea for use as a NO_X reduction reagent in SCR systems. Depending on a unit's control operating status, the representative cost at the 90th percentile unit (among the relevant fleet of coal units with SCR covered in this rulemaking) ranges between $900 and $1,700 per ton. The EPA performed an in-depth cost assessment for all coal-fired units with SCRs and found that for the subset of SCRs that are already partially operating, the cost of optimizing is often much lower than $1,600 per ton and is often under $900 per ton. The EPA anticipates the vast majority of realized cost for compliance with this strategy to be better reflected by the $900 per ton end of that range (reflecting the 90th percentile of EGUs optimizing SCRs that are already partially operating) because this circumstance is considerably more common than EGUs that have ceased operating their SCR. This cost distinction is reflected in the EPA's RIA cost estimates. When representing the cost of optimization here, the EPA uses the higher value to reflect both optimization of partially operating and idled controls. EPA's analysis of this emissions control is informed by the latest engineering modeling equations used in EPA's IPM platform. These cost and performance equations were recently updated in the summer of 2021 in preparation for this rule, and subsequently evaluated for the final rule in 2022 and determined to still be appropriate. The description and development of the equations are documented in EGU NO_X Mitigation Strategies Final Rule TSD and accompanying documents.[199] They are also implemented in an interactive spreadsheet tool called the Retrofit Cost Analyzer and applied to all units in the fleet. These materials are available in the docket for this action.

The EPA is using the same methodology to identify SCR performance as it did in the Revised CSAPR Update. To estimate EGU NO_X reduction potential from optimizing, the EPA considers the difference between the non-optimized NO_X emissions rates and an achievable operating and optimized SCR NO_X emissions rate. To determine this rate, EPA evaluated nationwide coal-fired EGU NO_X ozone season emissions data from 2009 through 2019 and calculated an average NO_X ozone season emissions rate across the fleet of coal-fired EGUs with SCR for each of these eleven years. The EPA found it prudent to not consider the lowest or second-lowest ozone season NO_X emissions rates, which may reflect SCR systems that have all new components (*e.g.,* new layers of catalyst). Data from these systems are potentially not representative of ongoing achievable NO_X emissions rates considering broken-in components and routine maintenance schedules. Considering the emissions data over the full time period from 2009–2019 results in a third-best rate of 0.079 pounds NO_X per million British thermal units (lb/mmBtu). Therefore, consistent with the Revised CSAPR Update, where EPA identified 0.08 lb/mmBtu as a reasonable level of performance for units with optimized SCR, the EPA finalizes a rate of 0.08 lb/mmBtu as the optimized rate for this rule. The EPA notes that half of the SCR-controlled EGUs achieved a NO_X emissions rate of 0.064 lb/mmBtu or lower over their third-best entire ozone season. Moreover, for the SCR-controlled coal units that the EPA identified as having a 2021 emissions rate greater than 0.08 lb/mmBtu, the EPA verified that in prior years, the majority (more than 90 percent) of these same units had demonstrated and achieved a NO_X emissions rate of 0.08 lb/mmBtu or less on a seasonal or monthly basis. This further supports EPA's determination that 0.08 lb/mmBtu reflects a reasonable emissions rate for representing SCR optimization at coal steam units in identifying uniform control stringency. This emissions rate assumption of 0.08 lb/mmBtu reflects what those units would achieve on average when optimized, recognizing that individual units may achieve lower or higher rates based on unit-specific configuration and dispatch patterns. Units historically performing at, or better, than this rate of 0.08 lb/mmBtu are assumed to continue to operate at that prior performance level.

Given the magnitude and duration of the air quality problems addressed by this rulemaking, the EPA also applied the same methodology to identify a reasonable level of performance for optimizing existing SCRs at oil- and gas-fired steam units and simple cycle units (for which EPA determined that a 0.03 lb/mmBtu emissions rate reflected SCR optimization) as well as at combined-cycle units (for which the EPA determined that a 0.012 lb/mmBtu emissions rate reflected SCR optimization).

The EPA evaluated the feasibility of optimizing idled SCRs for the 2023 ozone season. Based on industry past practice, the EPA determined that idled controls can be restored to operation quickly (*i.e.,* in less than 2 months). This timeframe is informed by many electric utilities' previous long-standing practice of utilizing SCRs to reduce EGU NO_X emissions during the ozone season while putting the systems into protective lay-up during the non-ozone season months. For example, this was the long-standing practice of many EGUs that used SCR systems for compliance with the NO_X Budget Trading Program. It was quite typical for SCRs to be turned off following the end of the ozone season control period on September 30. These controls would then be put into protective lay-up for several months of non-use before being returned to operation by May 1 of the following ozone season.[200] Therefore, the EPA believes that optimization of existing SCRs is possible for the portion of the 2023 ozone season covered under this final rule. The recent successful implementation of this strategy for the Revised CSAPR Update Rule, and corresponding fast improvement in SCR performance rates at units with optimization potential, provides further supporting evidence of the viability of this timeframe.

The vast majority of SCR-controlled units (nationwide and in the 23 linked states for which EPA is issuing a FIP for EGUs) are already partially operating these controls during the ozone season based on reported 2021 and 2022 emissions rates. Notably, the higher ozone season NO_X allowance price observed in 2022 resulted in more units operating their controls closer to their potential and bringing collective emissions from those 12 states closer to the 2023 emissions budgets for those states in this final rule, accordingly.

[199] The CSAPR Update estimated $1,400 per ton as a representative cost of turning on idled SCR controls. EPA used the same costing methodology while updating for input cost increases (*e.g.,* urea reagent) to arrive at $1,600 per ton in the final Revised CSAPR Update (while also updating from 2011 dollars to 2016 dollars).

[200] In the 22-state CSAPR Update region, 2005 EGU NO_X emissions data suggest that 125 EGUs operated SCR systems in the summer ozone season while idling these controls for the remaining 7 non-ozone season months of the year. Units with SCR were identified as those with 2005 ozone season average NO_X rates that were less than 0.12 lb/mmBtu and 2005 average non-ozone season NO_X emissions rates that exceeded 0.12 lb/mmBtu and where the average non-ozone season NO_X rate was more than double the ozone season rate.

Existing SCRs operating at partial capacity still provide functioning, maintained systems that may only require an increased chemical reagent feed rate (*i.e.,* ammonia or urea) up to their design potential and catalyst maintenance for mitigating NO_X emissions; such units may require increased frequency or quantity of deliveries, which can be accomplished within a few weeks. In many cases, EGUs with SCR have historically achieved more efficient NO_X removal rates than their current performance and can therefore simply revert to earlier operation and maintenance plans that achieved demonstrably better SCR performance.

In the 12 states subject to this control stringency in the Revised CSAPR Update, the EPA observed significant immediate-term improvements in SCR performance in the first ozone season following finalization of that rule, as evidenced in particular by the sharp drop in emissions rate at Miami Fort unit 7 (*see* EGU NO_X Mitigation Strategies Final Rule TSD). For instance, in June of 2021—within months of the Revised CSAPR Rule being finalized—Miami Fort Unit 7 and Unit 8 (which had substantial SCR optimization potential) were able to reach levels of 0.07 lb/mmBtu of NO_X (a greater than 50 percent reduction from where they had operated the prior year during the same month). Such empirical data further illustrates the viability of this mitigation strategy for the 2023 control period in response to this rule.

Comment: EPA received comments supporting the 0.08 lb/mmBtu emissions rate as achievable and, according to some commenters, underestimate the control's potential. Some of these commenters went on to provide their own analysis demonstrating that the 0.08 lb/mmBtu was achievable not only on average for the non-optimized fleet, but also for these individual units and that the resulting state emissions budgets were likewise achievable. Some commenters suggested that the rate should be lower and premised on EPA using the first- or second-best year instead of the third best year of SCR performance. Some commenters observed that using the same methodology, but omitting SCR units that have since retired, could deliver an even lower SCR performance benchmark rate.

Response: The EPA notes that updating the inventory of coal-fired EGUs to reflect recent retirements and to include data reported since 2019 (*e.g.,* 2009–2021) would provide a lower value of 0.071 lb/mmBtu. However, EPA acknowledges that 2020 operational data included impacts from COVID–19 pandemic shutdowns (such as atypical electricity demand patterns) which complicate interpretations of typical EGU emissions performance. Additionally, EPA believes that in this context, a unit's retirement in 2020 or 2021 does not obviate the usefulness of its prior SCR operational data for assessing the emissions control performance of other existing SCRs across the fleet. Consequently, EPA is continuing to use the same value of the 0.08 lb/mmBtu emissions rate calculated from the 2009–2019 data set identified at the time of the final Revised CSAPR Update Rule in this rulemaking. EPA's analysis focuses on the third best ozone season average rate because EPA believes that the first- or second-best rate, consistent with its CSAPR Update final rule and in the Revised CSAPR Update, could give undue weight to the emissions control performance of new SCRs in their first year of service and their corresponding newer SCR components. It does not necessarily reflect achievable ongoing NO_X emissions rates at relatively older SCRs. The third-lowest season was selected because it represents a time when the unit was most likely consistently and efficiently operating its SCR in a manner representative of sustained future operation.

Comment: Other commenters suggested that EPA should apply a higher NO_X emissions rate than 0.08 lb/mmBtu to existing SCR at coal EGUs premised on considerations such as: a generally reduced average capacity factor for coal units in recent years, the age of the boiler, coal rank (bituminous or subbituminous), or other unit-specific considerations that commenters claim make the 0.08 lb/mmBtu rate unattainable for a specific unit.

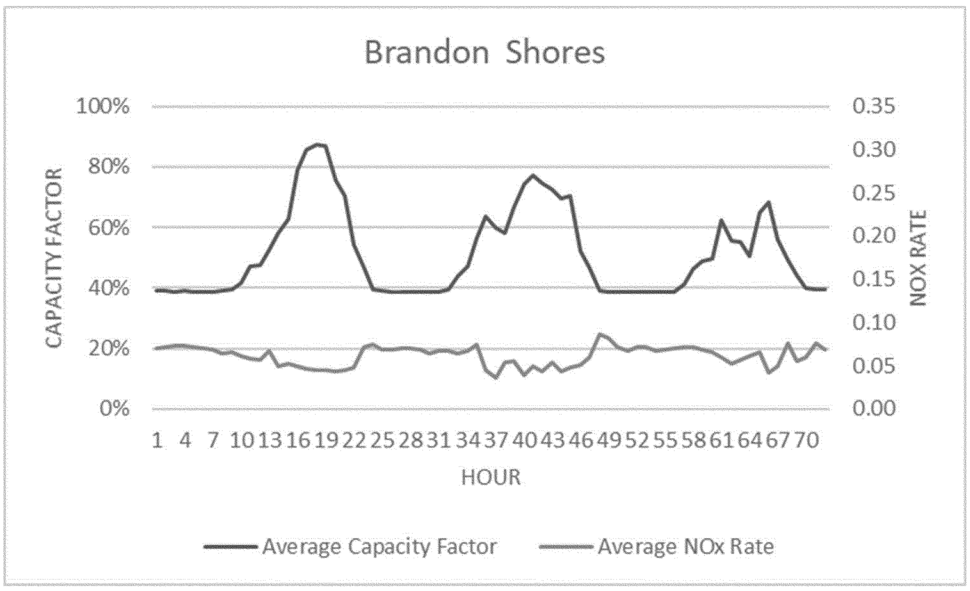
Response: EPA did not find sufficient justification to apply a higher average emissions rate than 0.08 lb/mmBtu. EPA found that some commenters were misunderstanding or misconstruing both EPA's assumption and implementation mechanism as a unit-level requirement for every SCR-controlled unit instead of a reflection of a fleet-wide average based on a third-best rate. The commenters' observation—that 0.08 lb/mmBtu may be difficult for some units to achieve or may not be a preferred compliance strategy for a given unit given its dispatch levels—does not contradict EPA's assumption, but rather supports its methodology and assumptions. As EPA pointed out in the proposed rule, this fleet-level emissions rate assumption of 0.08 lb/mmBtu for non-optimized units reflects, on average, what those units would achieve when optimized. Some of these units may achieve rates that are lower than 0.08 lb/mmBtu, and some units may operate above that rate based on unit-specific configuration and dispatch patterns. In other words, EPA is using this assumption as the average performance of a unit that optimizes its SCR, recognizing that heterogeneity within the fleet will likely lead some units to overperform and others to underperform this rate. Moreover, a review of unit-specific historical data indicates that this is a reasonable assumption: not only has the group of units with SCR optimization potential demonstrated they can perform at or better than the 0.08 lb/mmBtu rate on average, over 90 percent of the individual units in this group have already met this rate on a seasonal and/or monthly basis based on their reported historical data.

Additionally, EPA's examination of units experiencing SCR performance deterioration included notable instances of poor NO_X control at *increased* capacity factors. As an example, Miami Fort Unit 7 had considerably more hours of operation at a 70 to 79 percent capacity factor in 2019 compared to previous years. However, Miami Fort Unit 7's ozone-season NO_X emissions rate *substantially increased* in 2019 compared to previous years. This SCR performance deterioration runs counter to the notion that an increase in emissions rates is purely driven by reduced capacity factor, as suggested by commenters. This substantial deterioration in the median emissions rate performance is observable even when comparing specific hours in 2019 to specific hours in prior years when the unit operated in the same 70 to 79 percent capacity factor range. In fact, in 2019 the unit experienced notable emissions rate increases from prior years across multiple capacity factor ranges as low as 40 percent to as high as 80 percent. This type of data indicates instances where the increase in emissions rate (and emissions) is not necessitated by load changes but is more likely due to the erosion of the existing incentive to optimize controls (*i.e.,* the ozone-season NO_X allowance price has fallen so low that unit operators find it more economic to surrender additional allowances instead of continuing to operate pollution controls at an optimized level).

EPA observed this pattern in other units identified in this rulemaking as having significant SCR optimization emissions reduction potential. In the accompanying Emissions Data TSD for the supplemental notice that EPA recently released in a proceeding to address a recommendation submitted to EPA by the Ozone Transport Commission under CAA section 184(c), EPA noted, ''In their years with the lowest average ozone season NO_X emissions rates in this analysis, these EGUs had relatively low NO_X emissions rates at mid- and high-operating levels; moreover, there was little variability in NO_X emissions rates at these operating levels. However, during the 2019 ozone season, these EGUs had higher NO_X emissions rates and greater variability in NO_X emissions rates across operating levels than in the past, particularly at mid-operating levels.'' [201] That hourly data analysis, included in this docket, controls for operating level changes and still finds there to be instances across multiple SCR-controlled units where hourly emissions rates are increasing even when compared to the same load levels in previous years.

Some commenters have alleged that in recent years coal-fired EGUs have declined in capacity factor and that SCR performance declines at those lower operating levels. However, hourly data indicate that maintaining consistent SCR performance at lower capacity factors is possible. For example, the unit-level performance data in Figure 2 to section VI.B of this document show the emissions rate at a coal-fired EGU with existing SCR staying relatively low (consistent with our optimization assumption of 0.08 lb/mmBtu) and stable across a wide range of capacity factors.[202]

Figure 2 to section V.B.1.a: Example of Consistently Low Unit-level Emissions Rate During Periods of Varying Capacity Factor



Furthermore, most recent data from 2022 illustrates that cycling units do have the ability to adjust cycling patterns in a manner that enables them to maintain a lower emissions rate throughout the season while still achieving a load cycling pattern at the unit. For example, the SCR-controlled Conemaugh Unit 2 in Pennsylvania adjusted operating patterns in 2022 to have a slightly higher minimum load in most hours (maintaining a range of 550 MW–900 MW for most hours as opposed to 450 MW–900 MW observed in 2021). This change in minimum load, and corresponding minimum operating temperature, enabled the unit to maintain emissions rates in the 0.05 lb/mmBtu to 0.10 lb/mmBtu range for most of the 2022 season (as opposed to NO_X emissions rates that regularly exceeded 0.25 lb/mmBtu in the 2021 season). This 2022 improvement in SCR operation occurred during a period when allowance prices increased relative to prior years, creating an incentive for potential emissions reductions through SCR optimization.

Comment: EPA also received comment suggesting it should deviate from its approach in the CSAPR Update of using a nationwide data set of all SCR controlled coal units to establish a third best year, and instead limit the dataset to either just the covered states, or—in the case of some commenters—just to the baseline years of those units at which EPA is identifying optimization potential. They claim the current methodology may capture extremely efficient SCR performance years at the best performing units and that level of performance may not be available at all units with optimization potential. These commenters also disagree with the EPA finding that SCRs can consistently maintain a 0.08 lb/mmBtu rate over time.

Response: EPA reviewed the data and its methodology and evaluated it against its intention to identify a technology-specific representative emissions rate for SCR optimization. In doing so, EPA did not identify any need to make the suggested change. EPA is interested in the performance potential of a technology, and a larger dataset provides a superior indication of that potential as opposed to a smaller, state-limited dataset. Moreover, EPA's use of the third best year (as opposed to best) from its baseline period results in an average optimization level that is robust

[201] ''Analysis of Ozone Season NO_X Emissions Data for Coal-Fired EGUs in Four Mid-Atlantic States,'' EPA Clean Air Markets Division. December 2020. Available at *https://www.epa.gov/sites/production/files/2020-12/documents/184c_emission_data_tsd.pdf.*

[202] EPA, *Air Markets Program Data.* Available at *www.epa.gov/ampd.*

to the commenters' concern that EPA should not overstate the fleetwide representative optimization level. Prior experience with EPA's methodology and program has borne out empirical evidence of its reasonableness. In both the CSAPR Update and in Revised CSAPR Update rule, EPA appropriately relied on the largest dataset possible (*i.e.,* nationwide) to derive technology performance averages that it then applied respectively to the CSAPR Update 22-state region and the Revised CSAPR Update's 12-state region. EPA repeats that successful approach in this rule. Finally, as noted in the preceding paragraphs, in affirming the reasonableness of this approach, EPA examined the historical reported data (pre-2021) for the units in the states with SCR optimization potential and found the nationwide derived average appropriate and consistent with demonstrated capability and performance of units within those states. That is, the vast majority of units to which this resulting emissions rate assumption was being applied had demonstrated the ability to achieve this rate in some prior year for an extended monthly or seasonal basis. This information is discussed further in the EGU NO_X Mitigation Strategies Final Rule TSD in the docket.

Comment: Some commenters suggested the price of SCR optimization is higher than the $1,600 per ton figure proposed due to current market conditions for aqueous ammonia or other input prices.

Response: EPA provides a representative cost for this mitigation technology which is anticipated to reflect the cost, on average, throughout the compliance period for the rule. While there may be volatility in the market during that period where the price falls above or below the single representative threshold value, EPA's EGU NO_X Mitigation Strategies Final Rule TSD explains how the representative cost is derived and is inclusive of consultation and vetting by third party air pollution control consulting groups. Commenters did not demonstrate that observed 2021 elevated prices amid market volatility would continue into the future compliance periods discussed in this rule. Moreover, the selection of the mitigation technology is reflective of a variety of factors including reduction potential and air quality impact. A higher cost (commenter suggests up to $3,800 per ton) would not change EPA's determination that optimizing already existing SCRs is an appropriate mitigation strategy for Step 3 emissions reduction analysis in this rulemaking as it would remain one of the most widely available, widely practiced, and lowest cost mitigation measures with meaningful downwind air quality benefit. Appendix B of the EGU NO_X Mitigation Strategies Final Rule TSD further addresses commenters' concerns as it provides a variety of sensitivities showing cost per ton levels under a variety of different input assumptions (including higher material and reagent cost). It supports the continued inclusion of this technology in the rule even in the event that higher reagent costs extend into compliance years.

Comment: While many commenters supported the feasibility of 2023 ozone-season implementation by noting the ''immediate availability'' of SCR optimization, other commenters argued that the engineering, procurement, and other steps required for SCR optimization were not feasible given the anticipated limited window between rule finalization and the start of the 2023 ozone season.

Response: There is ample evidence of units restoring their optimal performance within a two-month timeframe. Not only do units reactivate SCR performance level at the start of an ozone-season when tighter emissions limits begin, but unit-level data also shows instances where sources have demonstrated the ability to quickly alter their emissions rate within an ozone-season and even within the same day in some cases. Moreover, this emissions control is familiar to sources and was analyzed and included in the Revised CSAPR Update emissions budgets finalized in 2021 and the CSAPR Update emissions budgets finalized in 2016. With this experience, and notice through the March 2022 proposed rule, as well as over two months from final rule to effective date, the viability of this emissions control for the 2023 ozone season is consistent with the 2-week to 2-month timeframe that EPA identified as reasonable in the CSAPR Update, Revised CSAPR Update, and in this rulemaking. Similar to prior rules, commenters provide some unit-level examples where it has taken longer. Also similar to those prior rules, EPA does not find those unit-level examples compelling in the context of its fleet average assumptions and in the implementation context of a trading program which provides compliance alternatives in the event a specific unit prefers more time to implement a given control measure. As noted in *Wisconsin,* ''. . . all those anecdotes show is that installation can drag on when companies are unconstrained by the ticking clock of the law.'' 938 F.3d at 330.

b. Installing State-of-the-Art NO_X Combustion Controls

The EPA estimates that the representative cost of installing state-of-the-art combustion controls is comparable to, if not notably less than, the estimated cost of optimizing existing SCR (represented by $1,600 per ton). State-of-the-art combustion controls such as low-NO_X burners (LNB) and over-fire air (OFA) can be installed or updated quickly and can substantially reduce EGU NO_X emissions. Nationwide, approximately 99 percent of coal-fired EGU capacity greater than 25 MW is equipped with some form of combustion control; however, the control configuration or corresponding emissions rates at a small portion of those units (including units in those states covered in this action) indicate they do not currently have state-of-the-art combustion control technology. For this rulemaking, the Agency re-evaluated its NO_X emissions rate assumptions for upgrading existing combustion controls to state-of-the-art combustion control. The EPA is maintaining its determination that NO_X emissions rates of 0.146 to 0.199 lb/mmBtu can be achieved on average depending on the unit's boiler configuration,[203] and, once installed, reduce NO_X emissions at all times of EGU operation.

These assumptions are consistent with the Revised CSAPR Update. They are further discussed in the EGU NO_X Mitigation Strategies Final Rule TSD. In particular, the EPA is finalizing, as proposed, the application of the 0.199 lb/mmBtu emissions rate assumption for both boiler types (tangentially and wall fired). EPA's analysis calculated average emissions rates of 0.199 lb/mmBtu for combustion controls on dry bottom wall fired units and 0.146 lb/mmBtu for tangentially fired units. However, many of the likely impacted units burn bituminous coal, and the 0.146 lb/mmBtu nationwide average for tangentially-fired (inclusive of subbituminous units) appears to be below the demonstrated emissions rate of state-of-the-art combustion controls for bituminous coal units of this boiler type. Therefore, EPA's assignment of a 0.199 lb/mmBtu emissions rate for combustion controls at all affected unit types is robust to current and future coal choice at a unit.

The EPA has previously examined the feasibility of installing combustion controls and found that industry had demonstrated ability to install state-of-

[203] Details of EPA's assessment of state-of-the-art NO_X combustion controls are provided in the EGU NO_X Mitigation Strategies Final Rule TSD.

the-art LNB controls on a large unit (800 MW) in under six months when including the pre-installation phases (design, order placement, fabrication, and delivery).[204] In prior rules, the EPA has documented its own assessment of combustion control timing installation as well as evaluated comments it received regarding installation of combustion controls from the Institute of Clean Air Companies.[205] Those comments provided information on the equipment and typical installation time frame for new combustion controls, accounting for all steps. To date, EPA has found it generally takes between 6–8 months on a typical boiler—covering the time through bid evaluation through start-up of the technology. The deployment schedule is repeated here as:

- 4–8 weeks—bid evaluation and negotiation
- 4–6 weeks—engineering and completion of engineering drawings
- 2 weeks—drawing review and approval from user
- 10–12 weeks—fabrication of equipment and shipping to end user site
- 2–3 weeks—installation at end user site
- 1 week—commissioning and start-up of technology

Given the referenced timeframe of approximately 6 to 8 months to complete combustion control installation in the region, the EPA is finalizing that installation of state-of-the-art combustion controls is a readily available approach for EGUs to reduce NO_X emissions by the start of the 2024 ozone season. More details on these analyses can be found in the *EGU NO_X Mitigation Strategies Final Rule TSD*.

The cost of installing state-of-the-art combustion controls per ton of NO_X reduced is dependent on the combustion control type and unit type. The EPA estimates the cost per ton of state-of-the-art combustion controls to be $400 per ton to $1,200 per ton of NO_X removed using a representative capacity factor of 85 percent. This cost fits well within EPA's representative cost threshold observed for SCR optimization and combustion controls (of $1,600 per ton) which would accommodate combustion control upgrade even under scenarios where a lower capacity factor is assumed. 99 percent of units have some form of combustion controls, indicating the widespread cost-effectiveness of this control. *See* the *EGU NO_X Mitigation Strategies Final Rule TSD* for additional details.

At proposal EPA assumed that emissions reductions from combustion control upgrades at affected EGUs in states subject to the Revised CSAPR Update program could occur by 2023 given that those EGUs may have already begun pursuing such upgrades in response to that previous rule. However, EPA does not have data to confirm that presumption, and hence EPA is determining in this final rule that combustion control upgrades for all affected EGUs, regardless of whether they were previously subject to the Revised CSAPR Update program, should be considered available by the 2024 ozone season, consistent with the deployment schedule noted in this section.

Comment: Some commenters suggested that EPA, in its modeling for the proposed rule, overestimated the ability of combustion control technologies to achieve very low NO_X emissions rates. The commenters claim EPA's assumptions are derived from projected NO_X emissions rates based on ideal circumstances for NO_X emissions reductions, including combinations of fuel composition and unit design that are not typical and should not be extrapolated to the national inventory.

Response: EPA's emissions performance rate for state-of-the-art combustion controls is derived from historical data and takes both boiler type and coal choice into account. EPA reviewed historical data and identified the average emissions rates for units with this technology already in place. It segmented this analysis by boiler type (dry-bottom wall-fired boiler and tangentially-fired, and further segmented by coal rank to assess the average performance among these varying parameters. As explained in the *EGU NO_X Mitigation Strategies Final Rule TSD,* EPA chose an emissions rate for which it verified accommodated (*i.e.,* was greater than or equal to) the average performance rate identified above for each boiler configuration with state-of-the-art combustion controls and resulted in reductions consistent with the technology's assumed percent reduction potential when applied to this subset of units. It also assessed whether the rate had been demonstrated by both subbituminous and bituminous coal units with state-of-the-art combustion controls. EPA further assessed the percent reduction that achieving this rate would require from the specific segment of the fleet identified as having this mitigation measure available. Here too, EPA found that the effective percent reduction for the identified fleet (inclusive of their existing coal rank choice) is well within the historical performance range for this technology. Therefore, EPA is finalizing the combustion control upgrade performance assumption of 0.199 lb/mmBtu as appropriate representative average performance rate for this technology and robust to different boiler types and coal ranks.

c. Optimizing Already Operating SNCRs or Turning on Idled Existing SNCRs

Optimizing already operating SNCRs or turning on idled existing SNCRs can also reduce EGU NO_X emissions quickly, using investments in pollution control technologies that have already been made. Compared to no post-combustion controls on a unit, SNCRs can achieve a 25 percent reduction on average in EGU NO_X emissions (with sufficient reagent). They are less capital intensive but less efficient at NO_X removal than SCRs. These controls are in use to some degree across the U.S. power sector. In the 22 linked states with EGU reductions identified in this final rule, approximately 11 percent of coal-fired EGU capacity is equipped with SNCR.[206] Recent power sector data suggest that, in some cases, SNCR controls have been operating less in 2021 relative to performance in prior years. For instance, EPA reviewed the last five years of performance data for all the units with SNCR optimization potential in its Engineering Analysis. It found that in 2021—the most recent year reviewed—that the weighted average ozone season emissions rate for these units was higher than the prior three years (indicating some deterioration in average performance). Moreover, a unit level review illustrated that 80 of the 107 units had performed better in a prior year by an average of 13 percent—indicating substantial optimization potential.[207]

The EPA determined that optimizing already operating SNCRs or turning on idled SNCRs is an available approach for EGUs to reduce NO_X emissions, has similar implementation timing to restarting idled SCR controls (less than 2 months for a given unit), and therefore could be implemented in time for the 2023 ozone season. In this final rule, the EPA is determining that this emissions

[204] The EPA finds that, generally, the installation phase of state-of-the-art combustion control upgrades—on a single-unit basis—can be as little as 4 weeks to install with a scheduled outage (not including the pre-installation phases such as permitting, design, order, fabrication, and delivery) and as little as 6 months considering all implementation phases.

[205] EPA–HQ–OAR–2015–0500–0093.

[206] *https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6*.

[207] See ''Historical Emission Rates for Units with SNCR Optimization Potential'' in the docket for this rulemaking.

control measure is available beginning in the 2023 ozone season.

Using the Retrofit Cost Analyzer described in the *EGU NO_X Mitigation Strategies Final TSD,* the EPA estimates a representative cost of optimizing SNCR ranging from approximately $1,800 per ton (for partially operating SNCRs) to $3,900 per ton (for idled SNCRs). For existing SNCRs that have been idled, unit operators may need to restart payment of some fixed and variable operating costs including labor, maintenance and repair, parasitic load, and ammonia or urea. The EPA determined that the majority of units with existing SNCR optimization potential were already partially operating their controls. Therefore, the EPA finalizes a representative cost of $1,800 per ton for SNCR optimization as this value best reflects the circumstances of the majority of the affected EGUs with SNCR.

d. Installing New SNCRs

The EPA evaluated potential emissions reductions and associated costs from retrofitting EGUs with new SNCR post-combustion controls at steam units lacking such controls, which can achieve a 25 percent NO_X reduction on average. New SNCR technology provides owners with a relatively less capital-intensive option for reducing NO_X emissions compared to new SCR technology, albeit at the expense of higher operating costs on a per-ton basis and less total emissions reduction potential. SNCR is more widely observed on relatively smaller coal units given its low capital/variable cost ratio. The average capacity of a coal unit with SNCR is half the size of the average capacity of coal unit with SCR.[208] Given these observations, the EPA identifies this technology as an emissions reduction measure for coal units less than 100 MW lacking post-combustion NO_X control technology. As described in the *EGU NO_X Mitigation Strategies Final Rule TSD,* the EPA estimated that $6,700 per ton reflects a representative SNCR retrofit cost level for these units.

For this rulemaking, EPA is not considering SNCR installation timing unto itself but is instead considering how long eligible EGUs may need to adopt either SNCR or SCR as a post-combustion control measure. SNCR installations generally have shorter project installation timeframes relative to other post-combustion controls. The time for engineering review, contract award, fabrication, delivery, and hookup is as little as 16 months including pre-contract award steps for an individual power plant installing controls on more than one boiler. However, SNCR retrofits have less pollution reduction potential than SCRs, and as explained further in the next section, the EPA is identifying the retrofit of new SCR rather than SNCR as a strategy for larger steam units due to this lower removal efficiency. This approach respects empirical evidence that larger coal-fired EGUs which installed post-combustion NO_X control technology have overwhelmingly chosen SCRs over SNCRs. Even for smaller units less than 100 MW identified as potential candidates for SNCR technology, the EPA does not want to preclude those units from pursuing SCR in lieu of SNCR.

Therefore, in this final rule the EPA defines the availability of emissions reductions from post-combustion control installation to be in 2026, the same period as the start of SCR-based reductions becoming available, to allow enough time for eligible EGUs to choose between SCR or SNCR. SNCR installation shares similar implementation steps with and also need to account for the same regional factors as SCR installations, which are described in the next section. While the EPA is determining that at least 16 months would be needed to complete all necessary steps of SNCR development and installation, an eligible EGU choosing new SCR instead would require installation timing of 36 to 48 months. EPA believes its finalized joint timing considerations for post-combustion control retrofits (SNCR and SCR) are justified given that post-combustion control retrofit decisions are subject to unit-specific economic and engineering factors and are sensitive to operator compliance strategy choices with respect to multiple regulatory requirements.

Comment: Some commenters argued that post-combustion control timing assumptions (SCR and SNCR) should be decoupled, which could result in the EPA using the 16-month time frame specific to SNCR installation to require emissions reductions related to new SNCR installations by the 2025 ozone season.

Response: The EPA does not agree that decoupling SCR and SNCR timing consideration is justified in the context of this final rule's emissions control program for EGUs. Approximately 1,000 tons of emissions reduction potential are estimated for the small coal EGUs deemed eligible for SNCR retrofit. The incentives provided through the implementation of this rule's trading program will encourage these EGUs to determine and adopt emissions reduction measures (including SNCR or SCR) as soon as possible to reduce their allowance holding compliance burden. By scheduling SNCR-related emissions reductions potential for the 2026 ozone season, the EPA preserves the opportunity for considerably superior emissions reduction potential from these EGUs should they select SCR retrofit instead, while still requiring post-combustion control emissions reduction potential ahead of the next attainment date.

Comment: Some commenters argued that the upper range of SNCR NO_X removal performance (40 percent) referenced by EPA is optimistic for many boilers.

Response: EPA evaluated both actual performance and engineering literature regarding SNCR retrofit technology and found both sources supported the range of reduction estimates cited by EPA. (Refer to the *EGU NO_X Mitigation Strategies Final Rule TSD* in the docket for this rulemaking for additional information.) Moreover, for purposes of calculating state budgets, EPA assumes 25 percent reduction from this technology—not 40 percent—which reflects a value well within the range of documented performance for this technology. Remaining comments on SNCR performance potential are addressed in the *RTC* Document and in the *EGU NO_X Mitigation Strategies Final Rule TSD.*

e. Installing New SCRs

Selective Catalytic Reduction (SCR) controls already exist on over 66 percent of the coal fleet in the linked states that are subject to a FIP in this rulemaking. Nearly every pulverized coal unit larger than 100 MW built in the last 30 years has installed this control, which is generally required for Best Available Control Technology (BACT) purposes. Other than circulating fluidized bed coal units which can achieve a comparably low emissions rate without this technology, the EPA identifies this emissions reduction measure for coal steam units greater than or equal to 100 MW. SCR is widely available for existing coal units of this size and can provide significant emissions reduction potential, with removal efficiencies of up to 90 percent. The EPA limited its consideration of SCR technology to steam units greater than or equal to 100 MW. The costs for retrofitting a plant smaller than 100 MW with SCR increase

[208] *See* EGU NO_X Mitigation Strategies Final Rule TSD for additional discussion.

rapidly due to a lack of economies of scale.[209]

The amount of time needed to retrofit an EGU with new SCR extends beyond the 2023 ozone season. Similar to the SNCR retrofits discussed in this section, the EPA evaluated potential emissions reductions and associated costs from this control technology, as well as the impacts and need for this emissions control strategy, at the earliest point in time when their installation could be achieved. EPA notes that it has previously determined in the context of ozone transport that regional scale implementation of SCRs at numerous EGUs is achievable in 36 months. *See* 63 FR 57356, 57447–50 (October. 27, 1998). However, since that time, the EPA has found up to 36–48 months to be a more appropriate installation timeframe for regionwide actions when the EPA is evaluating multiple installations at multiple locations.[210]

In the past, the EPA has found the amount of time to retrofit a single EGU with new SCR, depending on the regulatory program under which such control may be required, may vary between approximately 2 and 4 years depending on site-specific engineering considerations and on the number of installations being considered. This includes steps for engineering review, construction permit, operating permit, and control technology installation (including fabrication, pre hookup, control hookup, and testing). EPA's assessment of installation procedures suggests as little as 21 months may be needed for a single SCR at an individual plant and 36 months at a single plant with multiple boilers. EPA's assessment of units with SCR retrofit potential indicate the majority fall into this first classification, *i.e.,* a single SCR at a power plant.

While EPA finds that 36 months is a possible time frame for SCR installation at individual units or plants, the total of nearly 31 GW of coal capacity with SCR retrofit potential and 19 GW of oil/gas steam capacity with SCR retrofit potential within the geographic footprint of the final rule is a scale of retrofit activity that is not demonstrated to have been achieved within a three-year span based on data from the past two decades. Given that some of the assumed SCR retrofit potential occurs at plants with multiple units identified with retrofit potential, and given the total volume of SCR retrofit capacity being implemented across the region, EPA is allowing in this final rule between 36 to 48 months, consistent with the regional time frame discussed for SCR retrofit in prior rules, for the full implementation of reductions commensurate with this volume of SCR retrofit capacity, as described further in section VI.A of this document.

The Agency examined the cost for retrofitting a coal unit with new SCR technology, which typically attains controlled NO_X rates of 0.05 lb/mmBtu or less. These updates are further discussed in the EGU NO_X Mitigation Strategies Final Rule TSD.[211] Based on the characteristics of coal units of 100 MW or greater capacity that do not have post-combustion

NO_X control technology, the EPA estimated a weighted-average representative SCR cost of $11,000 per ton.[212]

The 0.05 lb/mmBtu emissions rate performance assumption for new SCR retrofits is supported by historical data and third party independent review by pollution control engineering and consulting firms. The EPA first examined unit-level emissions rate data for coal-fired units that had a relatively recent SCR installation (within the last 10 years). The best performing 10 percent of these SCRs were demonstrating seasonal emissions rates of 0.036 lb/mmBtu during this time.

While the EPA identified the 0.05 lb/mmBtu performance assumption consistent with historical data, these performance levels are also informed and consistent with the Agency's IPM modeling assumptions used for more than a decade. These modeling assumptions are based on input from leading engineering and pollution control consulting entities. Most recently, these data assumptions were affirmed and updated in the summer of 2021 and included in the docket for this rulemaking.[213] The EPA relies on a global firm providing engineering, construction management, and consulting services for power and energy with expertise in grid modernization, renewable energy, energy storage, nuclear power, and fossil fuels. Their familiarity with state-of-the art pollution controls at power plants derives from experience providing comprehensive project services—from consulting, design, and implementation to construction management, commissioning, and operations/maintenance. This review and update supported the 0.05 lb/mmBtu performance assumption as a representative emissions rate for new SCR across coal types.

The EPA performed an assessment for oil/gas steam units in which it evaluated the nationwide performance of those units with SCR technology. For these units, the EPA tabulated EGU NO_X ozone season emissions data from 2009 through 2021 and calculated an average NO_X ozone season emissions rate across the fleet of oil- and gas-fired EGUs with SCR for each of these years. The EPA identified the third lowest year which yielded an SCR performance rate of 0.03 lb/mmBtu as representative of performance for this retrofit technology applied to this type of EGU. Next, the EPA evaluated the emissions and operational characteristics for the existing oil/gas steam fleet lacking SCR technology. EPA's analysis indicated that the majority of reduction potential (approximately 76 percent) from these units occurred at units greater than or equal to 100 MW and that were emitting more than 150 tons per ozone season (*i.e.,* approximately 1 ton per day). Moreover, the cost of reductions for units falling below these criteria increased significantly on a dollar per ton basis. Therefore, the EPA identified the portion of the oil/gas steam fleet meeting these criteria (*i.e.,* greater than or equal to 100 MW and emitting more than 150 tons per ozone season) as representative of the SCR retrofit reduction potential.[214] For this segment of the oil/gas steam units lacking post-combustion NO_X control technology, the EPA estimated a weighted-average representative SCR cost of $7,700 per ton.

Comment: Some commenters disagreed with EPA's proposed 36-month timeframe for SCR retrofit. These commenters noted that, while possible at the unit or plant level, the collective volume of SCR installation occurring in

[209] IPM Model-Updates to Cost and Performance for APC Technologies. SCR Cost Development Methodology for Coal-fired Boilers. February 2022.

[210] *See, e.g.,* CSAPR Close-Out, 83 FR 65878, 65895 (December 21, 2018) and Revised CSAPR Update, 86 FR 23102 (April 30, 2021). *See also* Final Report: Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies, EPA–600/R–02/073 (Oct. 2002), available at *https://nepis.epa.gov/Adobe/PDF/P1001G0O.pdf.*

[211] As noted in that TSD, approximately half of the recent SCR retrofits (*i.e.,* installed in the last 10 years) have demonstrated an emission rate across the ozone season below 0.05 lb/mmBtu, even absent a requirement or strong incentive to operate at that level in many cases.

[212] This cost estimate is representative of coal units lacking any post-combustion control. A subset of units within the universe of coal sources with SCR retrofit potential, but that have an existing SNCR technology in place would have a weighted average cost that falls above this level, but still cost effective. See the EGU NO_X Mitigation Strategies Final Rule TSD for more discussion.

[213] See ''IPM Model—Updates to Cost and Performance for APC Technologies: SCR Cost Development Methodology for Coal-fired Boilers''.

[214] The EPA used a 3-year average of 2019–2021 reported ozone season emissions to derive a tons per ozone season value representative for each covered oil/gas steam unit.

a limited region of the country would not be possible given the labor constraints, supply constraints, and simultaneous outages necessary to complete SCR retrofit projects on such a schedule. They noted that achieving such a timeframe against a backdrop of such challenging circumstances is unprecedented and that EPA's assumptions ignore that many of the remaining unretrofitted coal units reflect more site-specific challenges than those that were already retrofitted on a quicker timeframe.

Response: EPA reviewed the comments and is making several changes in this final rule to address some of the concerns identified by the commenters. In particular, EPA found that its own review of historical retrofit patterns as well as technical information submitted by commenters supported commenters' concerns regarding: (1) current and anticipated constraints in labor and supply markets, (2) the potential collective capacity levels of SCR retrofit within 36 months, and (3) possible site-specific complexities at the remaining units without an existing SCR. To address these concerns, EPA is phasing in its SCR installation requirement over a 48-month time frame in this final rule, instead of a 36-month time frame as proposed (see additional detail and discussion in section VI.A.2.a and the EGU NO_X Mitigation Strategies Final Rule TSD). EPA will require half of the reductions associated with SCR installation in 2026 and the other half in 2027. Additionally, EPA is moving the daily backstop rate for these units with identified SCR reduction potential from 2027 to no later than 2030, which defers the increased allowance surrender ratio for emissions above the backstop rate at any outlier units unable to complete the retrofit during that time frame. These adjustments continue to incentivize reductions in NO_X emissions by the attainment date that are consistent with cost-effective SCR controls, but provide more flexibility (both from timing and technology perspective) in how they are procured.

Some commenters requested more than 48 months to install SCR controls based on the collective total volume of SCR retrofit volume identified and past projects that took five or more years. EPA disagrees with these comments and finds that they ignored key aspects of the proposed rule. First, the final rule does not directly require implementation of SCR; rather, it requires reductions commensurate with SCR installations based on a rigorous assessment of SCR retrofit potential. Implementing the reductions through a trading program means that sources in many cases, as suggested by the *Regulatory Impact Analysis (RIA),* will find alternative, and more economic means, of reducing emissions—including reduced generation and retirements that are already planned based on the age of the unit, decarbonization goals, or compliance with other Federal/state/local regulation compliance dates. Moreover, the additional new generation incentives provided by the Inflation Reduction Act (enacted after the proposed rule) will further increase the pace of new generation replacing some of the older generating capacity identified as having retrofit potential.[215] In short, although EPA identified the total SCR retrofit capacity potential for today's existing fleet and does not premise any reduction requirements of incremental retirements, the announced and planned futures for these units indicates that many will likely retire instead of installing SCR. For the capacity identified at Step 3 which lacks SCR, the planned or projected retirement in place of a retrofit moots the SCR timing for these units. Moreover, it also reduces the demand for associated labor and materials which, in turn, frees up resources for any units proceeding with a SCR retrofit. Therefore, comments which cite labor and supply chain challenges for accommodating the entire fleet capacity identified as having SCR retrofit potential significantly overstate the supply-side challenge—as it ignores the fact that much of this capacity has explicit or expected operation plans that will result in compliance without a retrofit.

Even for sources choosing a SCR retrofit compliance pathway, many of these comments ignore the timing flexibilities of the trading program, which (particularly with the changes to the backstop daily emissions rate in this final rule) allow sources to temporarily comply through means other than SCR retrofit if they experience any site-specific retrofit limitations that increase their time frame. Also, historical examples of SCR retrofit projects that exceeded 48 months in duration do not necessarily demonstrate that such projects are impossible in less than 48 months, but rather that they can extend beyond the timeframe if no requirements or incentives are in place for a faster installation. Some also cite site-specific conditions that resulted an outlier cases of project timing that would not be representative of the conditions expected at future retrofit projects.[216]

Comment: Some stakeholders suggested that EPA's cost estimates of $11,000 per ton are premised on a 15-year book life of the equipment and are therefore too optimistic for units that plan to retire in well under 15 years.

Response: EPA analysis of SCR retrofit cost reflects a representative value for the technology based on a weighted average cost. The underlying data and the discussion in the EGU NO_X Mitigation Strategies Final TSD illustrates that these costs can vary significantly at the unit level based on factors such as the length of time a pollution control technology would be in operation, the capacity factor of the unit (*i.e.,* how much does it operate), its size or potential to emit, and its baseline emissions rate. The EPA has not in prior transport rulemakings used such factors as justification to excuse any source that is significantly contributing to nonattainment or interfering with maintenance in another state from eliminating that significant contribution as expeditiously as practicable. Unlike under other statutory provisions that may require retrofit of emissions controls on existing sources, such as under CAA section 111(d) or CAA section 169A, there is no remaining useful life factor expressly identified as a justification to relax the requirements of CAA section 110(a)(2)(D)(i)(I). EPA continues to believe that where an emissions control strategy has been identified at Step 3 that is cost-effective on a regional scale and provides meaningful downwind air quality improvement, and is thus appropriately identified as necessary to eliminate significant contribution under the good neighbor provision, it would not be appropriate to allow emissions to continue in excess of those achievable emissions reductions beyond the timeframe for expeditious implementation of reductions as provided under the larger title I structure of the Act for attaining and maintaining the NAAQS. The court in *Wisconsin* recognized that where such emissions have been identified, they should be eliminated as expeditiously as practicable, and in line with the

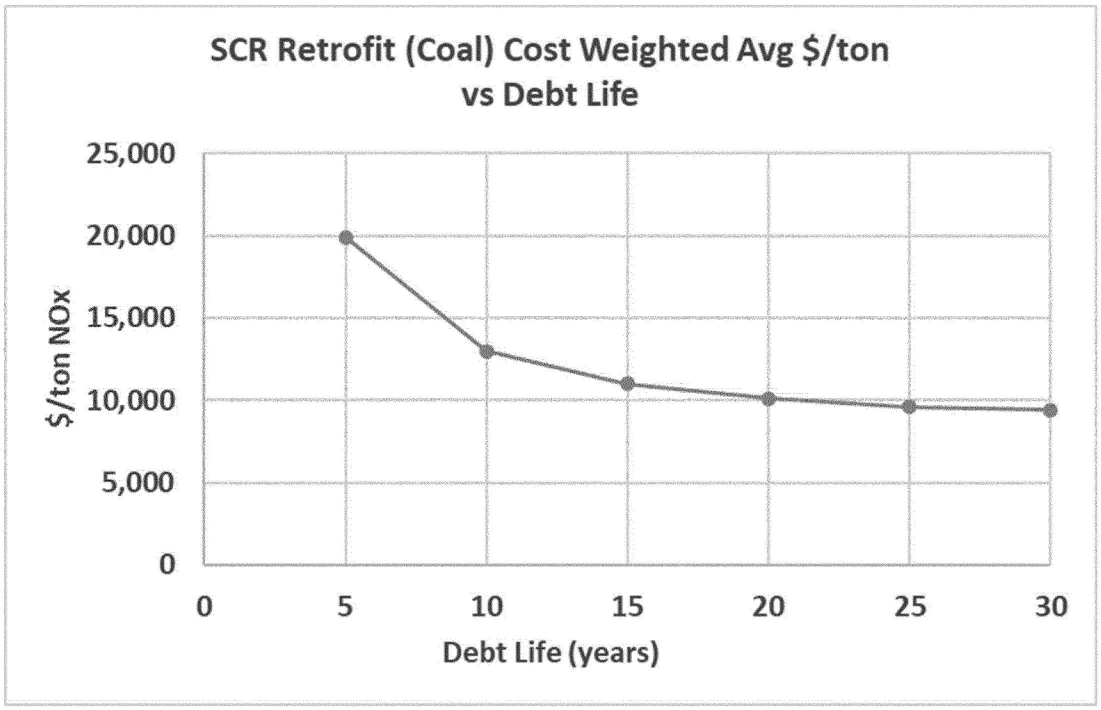
[215] *See* ''Regulatory Impact Analysis for 2015 Good Neighbor Plan, Appendix 4A: Inflation Reduction Act EGU Sensitivity Run Results.'' EPA estimated the compliance costs and emissions changes of the final rule in the presence of the IRA, but given time and resource constraints, did not quantify benefits for this sensitivity.

[216] Commenters, for example, cited the timing of SCR installation at Sammis 6 and 7. Here, the SCR design and material delivery schedule were tailored to meet unique site conditions that were unlike many other SCR systems where large modules can be used to maximize shop and ground assembly techniques. Additional information is available at *https://www.babcock.com/home/about/resources/success-stories/sammis-plant.*

attainment schedule for downwind areas, which, for the 2015 ozone NAAQS, is provided in CAA section 181. 938 F.3d at 313–20.

Further, EPA observes that more than one-third of the identified SCR retrofit potential (in terms of generating capacity) has no planned retirement date within 15 years, and therefore the cost of pollution control technology on such units would likely be lower, holding all other parameters equal, on a dollar per ton basis by virtue of the length of time the pollution control equipment may be in operation. Nor does EPA agree that units that would retire in less than 15 years should automatically be considered to face an unreasonably higher cost burden. Based on data analyzed in the EGU NO_X Mitigation Strategies Final Rule TSD, we find that the cost per ton associated with SCR retrofit technology does not begin to increase significantly above the $11,000/ton benchmark unless units have dramatically lower operating capacity or retire in less than 5 years' time—as illustrated in Figure 1 to section V.B.1.e of this document.

Figure 1 to section V.B.1.e: SCR Retrofit Cost Weighted Average $/ton vs Debt Life[217]



Finally, EPA's identification of this mitigation strategy is not meant to be limited only to units that experience a retrofit cost that is less than the representative cost threshold. First, that threshold represents an average, meaning that EPA's analysis already recognizes that some units on a facility-specific basis may face costs higher than that threshold. Further, EPA identifies this technology as widely available, implemented in practice already at many existing EGUs, and now standard for any coal-fired unit coming online in the past 25 years. More than 66 percent of the current large coal fleet already has such controls in place. Even if the cost were higher for some units for the reasons provided by commenters—and there were no less costly means provided to them to achieve the same level of emissions reduction (which the trading program allows for)—that would not necessarily obviate EPA's basis for finding that an emissions-reduction requirement commensurate with this standard pollution control practice for this unit type is warranted. The implementation of emissions reductions through a trading program, and its corresponding compliance flexibilities, make the use of a single representative cost all the more appropriate in this assessment. Therefore, upon reviewing all of the data including the information supplied by commenters, and even accounting for certain units' announced plans to retire earlier than an assumed 15-year book life for SCR retrofit technology, EPA finds its representative cost for this technology to be appropriate and reasonable for purposes of analysis under CAA section 110(a)(2)(D)(i)(I) and maintains this cost estimate in the final rule.

However, in recognition of the unique circumstances related to the transition of the power sector away from coal-fired and other high-NO_X emitting fuels and generating technologies, which is anticipated to accelerate in the late 2020s and into the 2030s, EPA has adjusted the final rule to avoid imposing a capital-intensive control technology retrofit obligation which could have overall net-negative environmental consequences (*e.g.,* by extending the life of a higher-emitting EGU or necessitating the allocation of material and personnel that could be used for more advanced clean-technology

[217] "Debt Life" refers to the term length, or duration, for a loan used to finance the retrofit.

innovations). For units that plan to retire by 2030, the final rule—by extending the daily backstop rate to 2030—allows these units to continue to operate, so long as they comply with the mass-based emissions trading program requirements.[218] Therefore, a unit experiencing a higher dollar per ton retrofit cost due to retirement plans has the flexibility to install less capital intensive controls such as SNCR, procure less costly allowances through either banking or purchase, or they may also reduce their allowance holding requirement through reduced utilization consistent with their phasing out towards a planned retirement date. This flexibility that EPA has included in the final rule is discussed in further detail in section VI.B of this document.

Comment: Some commenters suggested that the 0.05 lb/mmBtu emissions rate assumed for new SCRs at large coal units is not achievable at all coal units with retrofit potential and that EPA should raise this performance assumption to a value of 0.08 lb/mmBtu consistent with that assumption for existing SCRs.

Response: First, EPA believes the commenter misunderstands its intention with the 0.05 lb/mmBtu SCR rate assumption. This is meant to reflect a representative assumption for emissions rate performance for new SCR installed on the currently unretrofitted coal fleet—in this respect, it represents an average, not a maximum. EPA recognizes that some units will likely perform better (*i.e.,* lower) than this rate and some will potentially perform worse (*i.e.,* higher) than this rate—but that 0.05 lb/mmBtu is a reasonable representation of new SCR retrofit potential on a fleet-wide basis and for identifying expected state and regional emissions reduction potential from this technology. It would be inappropriate for EPA to use the worst performing tier of new SCR retrofit for this representative value. Moreover, EPA's review of historical environmental performance for recently installed SCRs does not support any indication that 0.05 is not representative of the retrofit potential for the fleet. EPA found that three quarters of the SCR retrofit projects completed in the last 15 years have achieved a rate of 0.05 lb/mmBtu or better on a monthly or seasonal basis. Moreover, its review of the engineering literature and consultation with third party pollution control engineering consultancies suggests that vendors are often willing to guarantee 0.05 lb/mmBtu seasonal performance for new SCR retrofit projects. Current SCR catalyst suppliers provide NO_X emissions warranties based at the catalyst's end-of-life period, often after 16,000 to 24,000 hours of operations, with newer catalyst achieving similar or better NO_X removal rates. Standard commercial terms, made by the purchaser to the SCR Retrofit supplier, can specify a system capable of meeting the proposed NO_X emissions rate and define the catalyst operational life before replacement. Thus, achieving the proposed reduction rates is accomplished through the buyer specifying the SCR retrofit requirements and the supplier providing an optimized system design and installing sufficient catalyst for the targeted end-of-life NO_X emissions rate. The agency is confident that SCR retrofit suppliers will be able to warrant their offerings for the emissions rates proposed in the regulation and to provide sufficient operating life for the affected sector.

Comment: Some commenters suggest that the evaluation of pollution control installation cost at Step 3 should be segmented depending on unit characteristics, and by failing to do so understate the cost of retrofitting SCR controls. In particular, these commenters note that units with lower capacity factors, different coal ranks, with pre-existing controls—such as SNCR—face substantially higher dollar per ton reduced costs than those that do not have such controls in place and should not be identified as a cost-effective mitigation strategy.

Response: Consistent with prior CSAPR rulemakings, at Step 3 EPA evaluates a mitigation technology and its representative cost and performance for the fleet on average. This representative cost is inclusive and robust to the portion of the fleet that may face higher dollar per ton cost. Both the ''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, EGU NO_X Mitigation Strategies Proposed Rule TSD'' (Feb. 2022), hereinafter referred to as the EGU NO_X Mitigation Strategies Proposed Rule TSD, and the EGU NO_X Mitigation Strategies Final TSD discuss the SCR retrofit cost specific to the segment of the fleet that has a SNCR in place and notes that those unit-level higher retrofit cost estimates are factored into its determination of the fleet-wide representative number. Although EPA believes its representative cost are appropriate and underpinned by operating assumptions reflective of the fleet averages, it nevertheless examined how cost would vary based on some of the variables highlighted by commenter. The EPA derived its capacity factor assumption based on expected future operations of this fleet segment that are inclusive of units operating at a range of capacity factors. It also examined how cost would change assuming different coal rank, assuming different book life, and different reagent cost. These analyses are discussed and shown in Appendix B of the EGU NO_X Mitigations Strategies Final Rule TSD and demonstrate that even under different operating assumptions, the variation in cost does not reach a point that would reverse EPA's finding regarding the appropriateness of this technology as part of this final rule's control stringency. Moreover, as discussed in section V.D of this document, EPA identifies appropriate mitigation strategies based on multiple factors—not solely on cost, and there is no indication that an individual unit's higher retrofit cost would obviate the appropriateness of retrofitting this standard and best practice technology at the unit. Finally, in prior rules and in the proposal, EPA recognized that some units will have higher cost and some will have lower cost relative the fleetwide representative value provided. Implementing the region and state reduction requirements through a mass-based trading program provides a means of alternative lower cost compliance for those sources particularly concerned about the higher retrofit cost at their unit.

Comment: Some commenters suggested that EPA's proposed representative cost for SCR pollution control is likely too high and overstates the true cost of such control. They also noted it aligns with agency precedent. These commenters claim that EPA's cost recovery factor is higher than necessary (thus inflating the cost) as it reflects a weighting of utility-owned to merchant-owned plants that is representative of the fleet, but not the unretrofitted fleet with this retrofit potential identified in this rule. They also noted that EPA's assumed interest rate informing the cost estimate was higher than the prime rate in June of 2022.

Response: EPA agrees that its approach for identifying representative cost thresholds is aligned with prior rules and agrees that its approach is reasonable. As the commenter points out, prime rates and cost recovery factors may indeed be lower in recent data than those assumed by EPA for future years. However, given the

[218] In the RIA, EPA has modeled the mass-based budgets that are premised on retrofit of SCR technology with the option of complying through other strategies, and finds that they are readily achievable through those other strategies.

volatility among these metrics, EPA believes its choices are appropriate to build cost estimates that are robust to future uncertainty, and if these cost input factors do materialize to be the lower values highlighted by commenter, then it will result in a lower cost assumed in this final rule, but would not otherwise alter any of the stringency identification or regulatory findings put forward in this final rule. EPA performed a cost sensitivity analysis in Appendix B of the EGU NO_X Mitigation Strategies Final Rule TSD which shows how cost for this technology would vary based on different assumed levels for this variable. This analysis shows that under lower interest rates such as those put forward by commenter, that technology cost would drop by approximately 15 percent relative to the representative values put forward in this rule.

f. Generation Shifting

At proposal, EPA considered intrastate emissions reduction potential from generation shifting across the representative dollar per ton levels estimated for the emissions controls considered in previous sections. As the cost of emitting NO_X increases, it becomes increasingly cost-effective for units with lower NO_X rates to increase generation, while units with higher NO_X rates reduce generation. Because the cost of generation is unit-specific, this generation shifting occurs incrementally on a continuum. Consequently, there is more generation shifting at higher cost NO_X-control levels.

The EPA recognizes that imposing a NO_X-control requirement on affected EGUs, like any environmental regulation, internalizes the cost of their pollution, which could result in generation shifting away from those sources toward other generators offering electricity at a lower pollution cost. If, in the context of a market-based allowance trading program form of implementation, the EPA imposes a preset emissions budget that is premised only on assumed installation, optimization, and continued operation of unit-specific pollution control technologies, with no accounting for the likely generation shift in the marketplace away from these higher-polluting sources, that preset emissions budget will contain more tons than would be emitted if the affected EGUs achieved the emissions performance level (on a rate basis) selected at step 3. Hence, EPA has previously quantified and required expected emissions reductions from generation shifting in prior transport rules to avoid undermining the program's incentive to install, optimize, and operate controls identified in the Agency's determinations regarding the requisite level of emissions control at Step 3. *See, e.g.,* 81 FR 74544–45; 76 FR 48280.

As in these prior rules, at proposal, the EPA did not identify generation shifting as a primary mitigation strategy and stringency measure on its own, but included emissions reductions from this strategy as it would be projected to occur in response to the selected emissions control stringency levels (and corresponding allowance price signals in step 4 implementation). For this rule's proposal, the EPA only specified emissions reductions from generation shifting in its preset budget calculations for 2023 and 2024. Because this rule's dynamic budget methodology applies the selected control stringency's emissions rates to the most recently reported heat input at each affected EGU, dynamic budgeting effectively serves a similar purpose to our ex ante quantification of emissions reduction potential from generation shifting for preset budgets in prior transport rules, *i.e.,* to adequately and continuously incentivize the implementation of the emissions control strategies selected at Step 3. Therefore, dynamic budgets under this rule's program moot the need to specify discrete emissions reduction potential from generation shifting for those control periods, as they automatically reflect whatever generation balance affected EGUs would determine in the marketplace inclusive of their response to the emissions performance levels imposed by this rule.

Comment: Commenters offered both support for and opposition against the inclusion of generation shifting at Step 3 analysis for EGUs. Those in support noted that inclusion of emissions reductions from generation-shifting is integral to the successful implementation of the pollution control measures identified in the selected control stringency at Step 3. Those opposed generally argued the EPA was overestimating reduction potential from generation shifting in light of recent volatility and high prices in the markets for lower emitting fuels such as natural gas. Commenters also noted the electrical grid in certain regions has constraints that would make generation shifting more difficult than the EPA assumed. Commenters also asserted that the EPA did not have the legal authority to require generation shifting.

Response: The EPA disagrees with these comments regarding our legal authority but notes this issue is not relevant for purposes of this final action. The EPA continues to believe it has authority under CAA section 110(a)(2)(D)(i)(I) to consider and require emissions reductions from generation shifting if the EPA were to find that strategy was necessary to eliminate significant contribution. However, based on circumstances currently facing affected EGUs, as well as the inherent strength of the dynamic budget methodology to automatically reflect the market-determined balance of generation across sources responding to this rule, the EPA is not specifying emissions reduction potential from generation shifting as a part of the Step 3 analysis, nor to require any emissions reductions from generation shifting in preset budgets formulated under Step 4 for any control period, for this final rule.

Currently observable market conditions (*e.g.,* fuel prices) present unusual uncertainty with respect to key economic drivers of generation shifting. The availability of emissions reductions through generation shifting, and the magnitude of those emissions, is dependent on the availability and cost of substitute generation. The primary driver of near-term generation shifting-based emissions reductions has been shifting to lower-emitting natural gas generation. Recent volatility and high prices in the natural gas market have increased the uncertainty and reduced the potential of this emissions control strategy at any given cost threshold in the near term. For example, Henry Hub natural gas prices went from under $3.00/mmBtu during most of the last decade to an average of nearly $8.00/mmBtu for the most recent (2022) ozone season before declining sharply at the start of 2023. The current volatility in natural gas prices reduces the availability of emissions reductions from generation shifting and make its identification and quantification too uncertain for incorporation into Step 3 emissions reduction estimates for this rulemaking.

The Step 4 dynamic budget-setting process of this rule obviates the need to specify and require discrete emissions reductions from generation shifting under Step 3. As discussed in section VI of this document, the EPA in this final rule will implement a budget-setting approach that relies on two components: first, we have calculated "preset" budgets that reflect the best information currently available about fleet change over the period 2023 through 2029. Second, beginning in 2026, dynamic state emissions budgets will be calculated that will reflect the balance of generation across sources reported to EPA by EGU operators. Between 2026 and 2029, the actual budget that will be implemented will reflect the greater of either the preset budget or the dynamic budget calculation; from 2030 onwards, the budgets will be set only through the dynamic budget calculation. This overall approach is well suited for a period of significant power sector transition driven by a variety of economic, policy, and regulatory forces and allows for the balance of generation in this period to adjust in response to these forces while nonetheless ensuring that the budgets will continuously incentivize the emissions control stringency identified at Step 3. See section VI.B.4 of this document for further discussion on the interaction of preset and dynamic budgets during the 2026–2029 time period. With these approaches, and on the present record before the Agency, we conclude that the estimation and incorporation of specified emissions reductions from generation shifting at Step 3 is not necessary to eliminate significant contribution from EGUs for the 2015 ozone NAAQS through this rule's program implementation.

In previous CSAPR rulemakings, the EPA included generation shifting in the budget setting process to capture those reductions that would occur through shifting generation as an economic response to the control stringency determined based on the selected NO_X control strategies. *See, e.g.,* 81 FR 74544–45. ''Because we have identified discrete cost thresholds resulting from the full implementation of particular types of emissions controls, it is reasonable to simultaneously quantify the reduction potential from generation shifting strategy at each cost level. Including these reductions is important, ensuring that other cost-effective reductions (*e.g.,* fully operating controls) can be expected to occur.'' EGU NO_X Mitigation Strategies Final Rule TSD (EPA–HQ–OAR–2015–0500–0554), at 11–12.

Commenters on this rule and prior transport rules have observed that using preset budgets to factor in generation shifting is flawed in that it results in EPA incorporating specific quantities of emissions reductions from discrete levels of generation shifting that are projected to occur but may in fact ultimately transpire differently in the marketplace. Commenters on this rule claim that other variables, such as constraints in transmission capacity or changes in fuel prices, can drive such differences in projected versus realized generation shifting, and these concerns are particularly exacerbated in a time of significant uncertainty around energy supplies and markets together with new laws passed by Congress (*e.g.,* the Infrastructure Investment and Jobs Act and the Inflation Reduction Act) driving the current transformation of the power sector. By refraining in this rule from specifying discrete emissions reductions from generation shifting in preset budgets and instead relying on a dynamic budgeting approach to reflect market-driven generation patterns, EPA ensures that its budgets remain sufficiently stringent over the long term to continually incentivize the emissions control stringency it determined to be cost-effective and therefore appropriate to eliminate significant contribution at Step 3. Thus, dynamic budgeting addresses the same concern that animated our use of generation shifting in the CSAPR rulemakings, but in doing so uses a market-following approach that will accommodate, over the long term, unforeseen drops or increases in heat input levels.

g. Other EGU Mitigation Measures

The EPA requested comment on whether other EGU ozone-season NO_X Mitigation technologies should be required to eliminate significant contribution. For instance, the EGU NO_X Mitigation Strategies Proposed and Final Rule TSDs discussed certain mitigation technologies that have been applied to ''peaking'' units (small, low-capacity factor gas combustion turbines often only operating during periods of peak demand).

Comment: Some commenters emphasized that simple cycle combustion turbines play a significant role in downwind contribution, and they highlight that states such as New York have imposed emissions limits on these sources acknowledging their impact on downwind nonattainment. These commenters suggest that EPA pursue and expedite the implementation of these or similar mitigation measures.

Response: As explained in greater detail in the EGU NO_X Mitigation Strategies Final TSD, both the configuration and operation of this segment of the EGU fleet reflects significant variability among units and across time. In other words, one unit may have a capacity factor in a given year that is one hundred times greater than a similar unit in that same year, or even than its own capacity factor from a preceding year. This type of variability and heterogeneity make it unlikely that there is a single cost-effective control strategy across this fleet segment, and commenters did not provide evidence to the contrary. EPA's analysis discussed in the EGU NO_X Mitigation Strategies Final Rule TSD highlights that there are 32 units emitting more than 10 tons per year on average for the 2019–2021 ozone seasons and lacking combustion controls or more advanced controls (totaling approximately 1,000 tons of ozone season NO_X emissions in 2021). EPA analysis estimates a representative cost of $22,000 per ton for dry low NO_X burners or ultra-low NO_X burners at these simple cycle combustion turbines, and over $100,000 per ton for SCR retrofit at some combustion turbines. Therefore, EPA does not identify any such uniform mitigation measure at Step 3 when estimating reduction potential.

Nonetheless, the EPA recognizes that these simple cycle combustion turbines may have cost-effective emissions-reduction opportunities. These units are included in the emissions trading program and therefore, as in prior transport rules, the program continues to subject them to an allowance holding requirement under this rule which will likely incentivize any available cost-effective NO_X reductions from these EGUs. For instance, emissions rates from these units in New York were considerably lower in 2022, when they faced a high allowance price, versus 2021, when the allowance price was much lower. Therefore, we find that the appropriate treatment of these units in this final rule is to continue to include them in the emissions trading program to incentivize cost-effective emissions reductions, but EPA does not find the magnitude or consistency of cost-effective mitigation potential to establish a specific increment of emissions reduction through a specific Step 3 emissions control determination. Moreover, while EPA's program will incentivize any available cost-effective reductions within this cadre of units (and such behavior is captured in its final program evaluation and modeling the *RIA*), it does not obviate the need for the other EGU cost-effective reductions elsewhere as suggested by some commenters.

2. Non-EGU or Stationary Industrial Source NO_X Mitigation Strategies

In the early stages of preparing the proposed FIP, the EPA evaluated air quality modeling information, annual emissions, and information about potential controls to determine which industries, beyond the power sector, could have the greatest impact on downwind receptors' air quality and therefore the greatest impact in providing ozone air quality improvements in affected downwind states through reducing those emissions. Specifically, the EPA conducted a screening assessment focused on individual emissions units with >100 tpy of actual NO_X emissions in 23 upwind states. Once the industries were identified, the EPA used its Control Strategy Tool to identify potential emissions units and control measures and to estimate emissions reductions and compliance costs associated with application of non-EGU emissions control measures. The technical memorandum ''Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026'' (''Non-EGU Screening Assessment'' or ''screening assessment'') lays out the analytical framework and data used to prepare proxy estimates for 2026 of potentially affected non-EGU facilities and emissions units, emissions reductions, and costs.[219]

This screening assessment was not intended to identify the specific emissions units subject to the proposed emissions limits for non-EGU sources but was intended to inform the development of the proposed rule by identifying proxies for (1) non-EGU emissions units that potentially had the most impact in terms of the magnitude of emissions and potential for emissions reductions, (2) potential controls for and emissions reductions from these emissions units, and (3) control costs from the potential controls on these emissions units. This information helped shape the proposed rule.

To further evaluate the industries and emissions unit types identified by the screening assessment and to establish the applicability criteria and proposed emissions limits, the EPA reviewed RACT rules, NSPS rules, NESHAP rules, existing technical studies, rules in approved SIP submittals, consent decrees, and permit limits. That evaluation is detailed in the Proposed Non-EGU Sectors TSD prepared for the proposed FIP.[220]

In this final rule, for purposes of this part of the Step 3 analysis, the EPA is retaining emissions control requirements for these industries and many of the emissions unit types included in the proposal. However, based on comments that credibly indicated in certain cases that emissions reduction opportunities are either not available for certain unit types or are at costs that are far greater than the EPA estimated at proposal, the EPA has changed the final rule to either remove or adjust the applicability criteria for such units. For a detailed discussion of the changes between the proposed FIP and this final rule, in emissions unit types included and in emissions limits, see section VI.C of this document. Tables I.B–2 through I.B–7 in section I.B of this document identify the emissions units and applicable emissions limitations, and Table II.A–1 in section II.A of this document identifies the industries included in the final rule.

For the final rule, to determine NO_X emissions reduction potential for the non-EGU industries and emissions unit types, with the exception of Solid Waste Combustors and Incinerators, we used a 2019 inventory prepared from the emissions inventory system (EIS) to estimate a list of emissions units captured by the applicability criteria for the final rule. For Solid Waste Combustors and Incinerators, the EPA estimated the list of covered units using the 2019 inventory, as well as the NEEDS-v6-summer-2021-reference-case workbook.[221] Based on the review of RACT, NSPS, NESHAP rules, as well as SIPs, consent decrees, and permits, we also assumed certain control technologies could meet the final emissions limits.[222] We did not run the Control Strategy Tool to estimate emissions reductions and costs and instead programmed the assessment using R.[223] Using the list of emissions units estimated to be captured by the final rule applicability criteria, the assumed control technologies that would meet the emissions limits, and information on control efficiencies and default cost/ton values from the control measures database (CMDB),[224] the EPA estimated NO_X emissions reductions and costs for the year 2026. We estimated emissions reductions using the actual emissions from the 2019 emissions inventory. In the assessment, we matched emissions units by Source Classification Code (SCC) from the inventory to the applicable control technologies in the CMDB. We modified SCC codes as necessary to match control technologies to inventory records.

The EPA recognized both at proposal and in the final rule that the cost per ton of emissions controls could vary by industry and by facility. The $7,500 marginal cost/ton threshold reflected in the Non-EGU Screening Assessment functioned as a relative, representative cost/ton level. Similar to the role of cost-effectiveness thresholds the EPA uses at Step 3 to evaluate EGU emissions control opportunities, this threshold is not intended to represent the maximum cost any facility may need to expend but is rather intended to be a representative figure for evaluating technologies to allow for a relative comparison between different levels of control stringency. The value was used to identify potentially cost-effective controls for further evaluation.

In the final rule, partly in recognition of the many comments indicating widely varying cost-per-ton values across industries and facilities, the EPA has updated its analysis of costs for the covered non-EGU industries. This data is summarized in the Technical Memorandum ''Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs,'' available in the docket. We further respond to comments on the screening assessment in section 2.2 of the response to comments document.

3. Other Stationary Sources NO_X Mitigation Strategies

As part of its analysis for this final rule, the EPA also reviewed whether NO_X mitigation strategies for any other stationary sources may be appropriate. In this section, the EPA discusses three classes of units that have historically been excluded from our interstate air transport programs: (1) solid waste incineration units, (2) electric generating units less than or equal to 25 MW, and (3) cogeneration units. EPA's initial assessment did not lead it to propose inclusion of the units in these categories. However, EPA requested comment on whether any particular units within this category may offer cost-effective reduction potential.

Based on our request for comment, comments received, and our further evaluation, the EPA is including emissions limits and associated control requirements for the ozone season for solid waste incinerator units in this final rule, in line with the requirements we laid out for comment at proposal. Our analysis in this final rule confirms that these units have emissions reductions of a magnitude, degree of beneficial impact, and cost-effectiveness that is on par with the units in other industrial sectors included in this final rule.

[219] The memorandum is available in the docket here: *https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150*.

[220] The TSD for the proposed FIP is available in the docket here: *https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145*.

[221] The workbook is available here: *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6*.

[222] The Final Non-EGU Sectors TSD is available in the docket.

[223] R is a free software environment for statistical computing and graphics. Additional information is available here: *https://www.r-project.org/*.

[224] More information about the Control Strategy Tool (CoST) and the control measures database (CMDB) can be found at the following link: *https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution*.

For electric generating units less than 25 MW and cogeneration units previously exempted from EGU emissions budgets established through ozone interstate transport rules, the EPA has determined that these units should not be treated as EGUs in this final rule.

The EPA provides a summary of these three segments, their emissions control opportunities, and potential air quality benefits in the following sections. Additional considerations are further discussed in the EGU NO_X Mitigation Strategies Final TSD and in the *RTC* Document.

a. Municipal Solid Waste Units

At proposal, the EPA solicited comments on whether NO_X emissions reductions should be sought from municipal waste combustors (MWCs) to address interstate ozone transport, specifically on potential emissions limits, control technologies, and control costs. The EPA requested comment on emissions limits of 105 ppmvd on a 30-day rolling average and a 110 ppmvd on a 24-hour block average based on determinations made in the June 2021 Ozone Transport Commission (OTC) *Municipal Waste Combustor Workgroup Report* (OTC MWC Report). *See* 87 FR 20085–20086. The OTC MWC Report found that MWCs in the Ozone Transport Region (OTR) are a significant source of NO_X emissions and that significant annual NO_X reductions could be achieved from MWCs in the OTR using several different technologies, or combination of technologies at a reasonable cost. The OTC MWC report is included in the docket for this action.

Comment: The EPA received multiple comments supporting the inclusion of emissions limits for MWCs in the final rule. Commenters noted that MWCs are significant sources of NO_X that contribute to ozone problems in the states covered by the proposal. Multiple commenters referenced the OTC MWC report to contend that NO_X emissions from MWCs could be significantly reduced at a reasonable cost. Some commenters reasoned that sources closer to downwind monitors, including MWCs, should be regulated as a more targeted approach and a means to prevent overcontrol of upwind sources. Commenters also noted that the OTC recently signed a memorandum of understanding (MOU) requesting that OTC member states develop cost effective solutions and select the strategy or combination of strategies, as necessary and appropriate, that provides both the maximum certainty and flexibility for that state and its MWCs. Additionally, multiple commenters noted that MWCs are often located in economically marginalized communities or communities of color. Lastly, one commenter stated that MWCs were arbitrarily excluded from the non-EGU screening assessment prepared for the proposal.

Response: As described in section VI.B.2 of the notice of proposed rulemaking, the EPA assessed emissions reduction potential from non-EGUs by preparing a screening assessment to identify those industries that could have the greatest air quality impact at downwind receptors. While the EPA did not prepare an updated non-EGU screening assessment in preparation for this final rule, the Agency did evaluate MWCs using the criteria developed in the screening assessment for proposal and determined that MWCs should be included in this rulemaking. A discussion of this analysis for MWCs is available in the *Municipal Waste Combustor Supplement to February 28, 2022 Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026,* which is available in the docket for this rule.

Considering EPA's conclusion that MWCs should be included in this final rule if EPA applied the same criteria developed in the screening assessment for proposal, the findings from the OTC MWC report and recent MOU, the fact that many state RACT NO_X rules apply to MWCs, and information received during public comment, the EPA finds that MWCs should be included in this final rule. Thus, the EPA is finalizing NO_X emissions limits and compliance assurance requirements for large MWCs as defined in the regulatory text at § 52.46 and as described in this section.

Comment: Some commenters did not support the inclusion of emissions limits for MWCs in the final rule. Some commenters suggested that the inclusion of NO_X limits in a FIP is not necessary to continue to reduce NO_X emissions from MWCs or to address interstate transport problems. Some commenters noted that many of the MWCs in the states covered by the proposal are already subject to RACT-based NO_X emissions limits that are below the current Federal NSPS NO_X emissions limits for MWCs under 40 CFR part 60, subparts Cb and Eb. One commenter noted that MWCs do not always account for a large percentage of statewide NO_X emissions. Others suggested that voluntary industry actions are also driving downward trends of NO_X emissions for some MWCs. Some commenters also asserted that regulation could interfere with state waste reduction policies and associated environmental considerations.

Response: Regarding the comments that some MWCs are already subject to RACT NO_X emissions limits, the EPA acknowledges that some states included in this rulemaking have promulgated RACT NO_X emissions limits that apply to certain MWCs, including some that are lower than current MWC NSPS NO_X emissions limits. The EPA does not consider a source to be exempt from this rulemaking just because the source may be subject to other regulatory requirements. As noted, the Agency did evaluate MWCs using the criteria developed in the screening assessment for proposal and has concluded that MWCs should be included in this rulemaking. In considering the emissions limits that are being finalized in this rulemaking, the EPA reviewed existing state RACT rules as described in section VI.C.6 of this document and the ''Technical Support Document (TSD) for the Final Rule, Docket ID No. EPA–HQ–OAR–2021–0668, Non-EGU Sectors TSD'' (Mar. 2023), hereinafter referred to as Final Non-EGU Sectors TSD. We note that sources already subject to RACT NO_X emissions limits that are equal to or more stringent than the limits finalized in this rulemaking will have the option to streamline regulatory requirements through the Title V permitting process.

Regarding the statement that regulation could interfere with state waste reduction policies and associated environmental considerations, the EPA acknowledges that MWCs serve an important role in municipal solid waste management programs, and that many function as cogeneration facilities that produce electrical power for the power grid. The EPA also analyzed control costs and determined that the required NO_X emissions limits for MWCs can be achieved at a reasonable cost, as described in section VI.C.6 of this document, the Final Non-EGU Sectors TSD, and the OTC MWC Report. Although the EPA does not expect these regulations to disrupt the ability of the industry to provide municipal solid waste and electric services, to the extent a facility is unable to comply with the standards due to technical impossibility or extreme economic hardship, the final rule includes provisions for facility operators to apply for a case-by-case alternative emissions limit. *See* section VI.C of this document and 40 CFR 52.40(d). In addition, for MWC facilities that are unable to comply with the standard by the 2026 ozone season, the final rule includes provisions for requesting limited extensions of time to comply. *See* section VI.C and 40 CFR 52.40(c).

b. Electric Generating Units Less Than or Equal to 25 MW

The EPA has historically not included control requirements for emissions for electric generating units less than or equal to 25 MW of generation for three primary reasons: low potential reductions, relatively high cost per ton of reduction, and high monitoring and other compliance burdens. In the January 11, 1993, Acid Rain permitting rule, the EPA provided for a conditional exemption from the emissions reduction, emitting, and emissions monitoring requirements of the Acid Rain Program for new units having a nameplate capacity of 25 MWe or less that burn fuels with a sulfur content no greater than 0.05 percent by weight, because of the *de minimis* nature of their potential SO_2, CO_2 and NO_X emissions. *See* 63 FR 57484. The NO_X SIP Call identified these as *Small Point Sources.* For the purposes of that rulemaking, the EPA considered electricity generating boilers and turbines serving a generator 25 MWe or less, to be small point sources. The EPA noted that the collective emissions from small sources were relatively small and the administrative burden to the states and regulated entities of controlling such sources was likely to be considerable. As a result, the rule did not assume reductions from those sources in state emissions budgets requirements (63 FR 57402). Similar size thresholds have been incorporated in subsequent transport programs such as CAIR and CSAPR. As these sources were not identified as having cost-effective reductions and so were not included in those programs, they were also exempted from certain reporting requirements and the data for these sources is, therefore, not of the same caliber as that of covered larger sources.

EPA's preliminary survey of current data, compared to this initial justification, does not appear to offer a compelling reason to depart from this past practice by requiring emissions reductions from these small EGU sources as part of this rule. For instance, as explained in the EGU NO_X Mitigation Strategies Final Rule TSD, EPA has evaluated the costs of SCR retrofits at small EGUs using its Retrofit Cost Analyzer and found that such controls become markedly less cost-effective at lower levels of generating capacity. This analysis concluded that, after controlling for all other unit characteristics, the dollar per ton cost for a SCR retrofit increases by about a factor of 2.5 when moving from a 500 MW to a 10 MW unit, and a factor of 8 when moving to a 1 MW unit.[225] Moreover, the EPA estimates that under 6 percent of nationwide EGU emissions come from units that are less than 25 MW and not covered by current applicability criteria due to this size exemption threshold. Therefore, the EPA is not finalizing any emissions reductions for these units.

Comment: EPA received comment supporting the continued application of the 25 MW threshold.

Response: Consistent with prior rules, the proposal, and stakeholder comment, EPA is continuing to apply its 25 MW applicability threshold for EGUs in this rulemaking. EPA did not find compelling comment to reverse its determination that (1) these sources offer low potential reductions, (2) have relatively high cost per ton, and (3) have high monitoring and other compliance burdens.

c. Cogeneration Units

Consistent with prior transport rules, fossil fuel-fired boilers and combustion turbines that produce both electricity and useful thermal energy (generally referred to as ''cogeneration units'') and that meet the applicability criteria to be included in the CSAPR NO_X Ozone Season Group 3 Trading Program would be subject to the emissions reduction requirements established in this rulemaking for EGUs. However, those applicability criteria—which the EPA is not altering in this rulemaking (*see* section VI.B.3 of this document)—exempt some cogeneration units from coverage as EGUs under the trading program. The EPA is finalizing that fossil fuel-fired boilers and combustion turbines that produce both electricity and useful thermal energy and that do not meet the applicability criteria to be included in the CSAPR NO_X Ozone Season Group 3 Trading Program as EGUs would not be subject to the Group 3 emissions trading program. However, to the extent a cogeneration unit meets the applicability criteria for industrial non-EGU boilers covered by this rule, that unit will be subject to the relevant requirements and is not exempted by virtue of being a cogeneration unit.

According to information contained in the EPA's Combined Heat and Power Partnership's document ''Catalog of CHP Technologies'',[226] there are 4,226 CHP installations in the U.S. providing 83,317 MWe of electrical capacity. Over 99 percent of the installations are powered by 5 equipment types, those being reciprocating engines (52 percent), boilers/steam turbines (17 percent), gas turbines (16 percent), microturbines (8 percent), and fuel cells (4 percent). The majority of the electrical capacity is provided by gas turbine CHP systems (64 percent) and boiler/steam turbine CHP systems (32 percent). The various CHP technologies described herewith are available in a large range of sizes, from as small as 1 kilowatt reciprocating engine systems to as large as 300 megawatt gas turbine powered systems.

NO_X emissions from rich burn reciprocating engine, gas turbine, and microturbine systems are low, ranging from 0.013 to 0.05 lb/mmBtu. NO_X emissions from lean burn reciprocating engine systems and gas-powered steam turbines systems range from 0.1 to 0.2 lb/mmBtu. The highest NO_X emitting CHP units are solid fuel-fired boiler/steam turbine systems which emit NO_X at rates ranging from 0.2 to 1.2 lb/mmBtu.

Under the final rule (consistent with prior CSAPR rulemakings), certain cogeneration units would be exempt from coverage under the CSAPR NO_X Ozone Season Group 3 Trading Program as EGUs. Specifically, the trading program regulations include an exemption for a unit that qualifies as a cogeneration unit throughout the later of 2005 or the first 12 months during which the unit first produces electricity and continues to qualify through each calendar year ending after the later of 2005 or that 12-month period and that meets the limitation on electricity sales to the grid. To meet the trading program's definition of ''cogeneration unit'' under the regulations, a unit (*i.e.,* a fossil-fuel-fired boiler or combustion turbine) must be a topping-cycle or bottoming-cycle type that operates as part of a ''cogeneration system.'' A cogeneration system is defined as an integrated group of equipment at a source (including a boiler, or combustion turbine, and a generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy. A topping-cycle unit is a unit where the sequential use of energy results in production of useful power first and then, through use of reject heat from such production, in production of useful thermal energy. A bottoming-cycle unit is a unit where the sequential use of energy results in production of useful thermal energy first, and then, through use of reject heat from such production, in production of useful

[225] Preliminary estimate based on representative coal units with starting NO_X rate of 0.2 lb/mmBtu, 10,000 BTU/kwh, and assuming 80 percent reduction.

[226] This document is available at: *https://www.epa.gov/sites/default/files/2015-07/documents/catalog_of_chp_technologies.pdf.*

power. To qualify as a cogeneration unit, a unit also must meet certain efficiency and operating standards in 2005 and each year thereafter. The electricity sales limitation under the exemption is applied in the same way whether a unit serves only one generator or serves more than one generator. In both cases, the total amount of electricity produced annually by a unit and sold to the grid cannot exceed the greater of one-third of the unit's potential electric output capacity or 219,000 MWh. This is consistent with the approach taken in the Acid Rain Program (40 CFR 72.7(b)(4)), where the cogeneration-unit exemption originated.

The EPA requested comment on requiring fossil fuel-fired boilers in the non-EGU industries identified in section VI.C of this document that serve electricity generators and that qualify for an exemption from inclusion in the CSAPR NO_X Ozone Season Group 3 Trading Program as EGUs to instead meet the same emissions standards, if any, that would apply under this rulemaking to fossil fuel-fired boilers at facilities in the same non-EGU industries that do not serve electricity generators.

Comment: Some stakeholders support the continued exclusion of qualifying cogenerators from the EGU program, but suggested they be regulated as non-EGUs if they don't fit the EGU applicability criteria.

Response: The EPA agrees that there is no basis within the four-step framework to exempt cogeneration units that fall under the applicability criteria of the final rule for non-EGU boilers simply because they are cogeneration units. While cogeneration units do have environmental benefits as noted at proposal, some cogeneration unit-types, particularly boilers, are estimated to have NO_X emissions that would otherwise meet this rule's criteria at Step 3 for constituting ''significant contribution.'' These units can meet the emissions limits that are otherwise finalized for these unit types, and the EPA does not find a basis to exclude them simply because they may have other environmentally-beneficial attributes.

These emissions limits are set forth in section VI.C.5 of this document. Therefore, the final requirements for non-EGUs do not exempt cogeneration units and any cogeneration emissions units meeting the applicability criteria for non-EGUs will be subject to the final emissions limits for the appropriate non-EGU emissions unit. Based on EPA's review of available data, across all of the non-EGU industries covered by this rule, there are four cogeneration boilers (two in Pulp and Papermill and two in Basic Chemical Manufacturing) that would meet the final rule's applicability criteria for non-EGU units and are included in the analysis of non-EGU emissions reduction potential in section V.C.2 of this document.

4. Mobile Source NO_X Mitigation Strategies

Under a variety of CAA programs, the EPA has established Federal emissions and fuel quality standards that reduce emissions from cars, trucks, buses, nonroad engines and equipment, locomotives, marine vessels, and aircraft (*i.e.,* ''mobile sources''). Because states are generally preempted from regulating new vehicles and engines with certain exceptions (*see generally* CAA section 209), mobile source emissions are primarily controlled through EPA's Federal programs. The EPA has been regulating mobile source emissions since it was established as a Federal agency in 1970, and all mobile source sectors are currently subject to NO_X emissions standards. The EPA factors these standards and associated emissions reductions into its baseline air quality assessment in good neighbor rulemaking, including in this final rule. These data are factored into EPA's analysis at Steps 1 and 2 of the 4-step framework. As a result of this long history, NO_X emissions from onroad and nonroad mobile sources have substantially decreased (73 percent and 57 percent since 2002, for onroad and nonroad, respectively) [227] and are predicted to continue to decrease into the future as newer vehicles and engines that are subject to the most recent, stringent standards replace older vehicles and engines.[228]

For example, in 2014, the EPA promulgated new, more stringent emissions and fuel standards for light-duty passenger cars and trucks.[229] The fuel standards took effect in 2017, and the vehicle standards phase in between 2017 and 2025. Other EPA actions that are continuing to reduce NO_X emissions include the Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements (66 FR 5002; January 18, 2001); the Clean Air Nonroad Diesel Rule (69 FR 38957; June 29, 2004); the Locomotive and Marine Rule (73 FR 25098; May 6, 2008); the Marine Spark-Ignition and Small Spark-Ignition Engine Rule (73 FR 59034; October 8, 2008); the New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder Rule (75 FR 22895; April 30, 2010); and the Aircraft and Aircraft Engine Emissions Standards (77 FR 36342; June 18, 2012).

Most recently, EPA finalized more stringent emissions standards for NO_X and other pollution from heavy-duty trucks (Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards, 88 FR 4296, January 24, 2023). These standards will take effect beginning with model year 2027. Heavy-duty vehicles are the largest contributor to mobile source emissions of NO_X and will be one of the largest mobile source contributors to ozone in 2025.[230] Reducing heavy-duty vehicle emissions nationally will improve air quality where the trucks are operating as well as downwind. The EPA's existing regulatory program for mobile sources will continue to reduce NO_X emissions into the future.

Comment: The EPA received comments on ozone-precursor emissions from mobile sources, including cars, trucks, trains, ships, and planes. Commenters broadly encouraged the EPA to require emissions reductions from mobile sources in this rule. Commenters stated that the transportation sector plays a significant role in NO_X pollution and ozone formation and urged the EPA to finalize emissions reductions for the transportation sector that will enable attainment of the 2015 ozone NAAQS. Some commenters noted that high proportions of NO_X emissions in various upwind states are attributable to the transportation sector, and stated that EPA should have targeted emissions reductions from mobile sources first before requiring more stringent emissions controls from stationary sources in the same upwind states.

Response: The EPA agrees with commenters that a variety of sources, including mobile sources in the transportation sector, produce NO_X emissions that contribute to ozone air quality problems across the U.S. This rule, as with prior interstate transport actions, does not ignore those emissions, and it credits those on-the-books measures of states and the Federal Government within the four-step framework by including emissions and

[227] US EPA. Our Nation's Air: Status and Trends Through 2019. *https://gispub.epa.gov/air/trendsreport/2020/#home*.

[228] National Emissions Inventory Collaborative (2019). 2016v1 Emissions Modeling Platform. Retrieved from *http://views.cira.colostate.edu/wiki/wiki/10202*.

[229] Control of Air Pollution from Motor Vehicles: Tier 3 Motor Vehicle Emissions and Fuel Standards, 79 FR 23414 (April 28, 2014).

[230] Zawacki et al, 2018. Mobile source contributions to ambient ozone and particulate matter in 2025. Atmospheric Environment. Vol 188, pg 129–141. Available online: *https://doi.org/10.1016/j.atmosenv.2018.04.057*.

emissions reductions from these sources in the emissions inventory for air quality modeling, which informs Steps 1 and 2 of this analysis. Thus, this rule accurately represents emissions from mobile sources that are used to evaluate the contribution of states to ozone air quality problems in other states. See section IV.C of this document.

The EPA notes that its Step 3 analysis for this FIP does not assess additional emissions reductions opportunities from mobile sources. The EPA continues to believe that title II of the CAA provides the primary authority and process for reducing these emissions at the Federal level. EPA's various Federal mobile source programs, summarized above in this section, have delivered and are projected to continue to deliver substantial nationwide reductions in both VOCs and NO_X emissions; these reductions from final rules are factored into the Agency's assessment of air quality and contributions at Steps 1 and 2. Further, states are generally preempted from regulating new vehicles and engines with certain exceptions, and therefore a question exists regarding the EPA's authority to address such emissions through such means when regulating in place of the states under CAA section 110(c). *See generally* CAA section 209. *See also* 86 FR 23099.[231] In any case, the existence of mobile source emissions noted by commenters does not lead to the conclusion that the EPA must require mobile source reductions in this rule or that the EPA has not properly identified ''source[s] or other type[s] of emissions activity'' in upwind states that ''significantly contribute'' for purposes of the Good Neighbor Provision. The EPA is committed to continuing the effective implementation and enforcement of current mobile source standards and continuing its efforts on new standards. The EPA will continue to work with state and local air agencies to incorporate emissions reductions from the transportation sector into required ozone attainment planning elements.

C. Control Stringencies Represented by Cost Threshold ($ per ton) and Corresponding Emissions Reductions

1. EGU Emissions Reduction Potential by Cost Threshold

For EGUs, as discussed in section V.A of this document, the multi-factor test considers increasing levels of uniform control stringency in combination with considering total NO_X reduction potential and corresponding air quality improvements. The EPA evaluated EGU NO_X emissions controls that are widely available (described previously in section V.B.1 of this document), that were assessed in previous rules to address ozone transport, and that have been incorporated into state planning requirements to address ozone nonattainment.

The EPA evaluated the EGU sources within the State of California and found there were no covered coal steam sources greater than 100 MW that would have emissions reduction potential according to EPA's assumed EGU SCR retrofit mitigation technologies.[232] The EGUs in the state are sufficiently well-controlled resulting in the lowest fossil-fuel emissions rate and highest share of renewable generation among the 23 states examined at Step 3. EPA's Step 3 analysis, including analysis of the emissions reduction factors from EGU sources in the state, therefore resulted in no additional emissions reductions required to eliminate significant contribution from any EGU sources in California.

The following tables summarize the emissions reduction potentials (in ozone season tons) from these emissions controls across the affected jurisdictions. Table V.C.1–1 focuses on near-term emissions controls while Table V.C.1–2 includes emissions controls with extended implementation timeframes.

TABLE V.C.1–1—EGU OZONE-SEASON EMISSIONS AND REDUCTION POTENTIAL (TONS)—2023

State	Baseline 2023 OS NO_X	Reduction potential (tons) for varying levels of technology inclusion		
		SCR optimization	SCR optimization + combustion control upgrades	SCR/SNCR optimization + combustion control upgrades
Alabama	6,412	32	32	32
Arkansas	8,955	28	28	28
Illinois	7,721	70	70	247
Indiana	13,298	856	856	858
Kentucky	13,900	299	901	901
Louisiana	9,974	515	515	611
Maryland	1,214	0	0	8
Michigan	10,746	4	4	19
Minnesota	5,643	98	98	139
Mississippi	6,283	73	984	984
Missouri	20,094	7,339	7,339	7,497
Nevada	2,372	4	4	4
New Jersey	915	143	143	143
New York	3,977	64	64	64
Ohio	10,264	1,154	1,154	1,154
Oklahoma	10,470	199	890	890
Pennsylvania	8,573	336	336	436
Texas	41,276	909	909	1,142
Utah	15,762	7	7	7
Virginia	3,329	164	242	263
West Virginia	14,686	554	1,099	1,380

[231] This is not to say that states lack other options to reduce emissions from mobile sources. For example, a general list of types of transportation control measures can be found in CAA section 108(f). In addition, in accordance with section 177, states may (but are not required to) adopt California vehicle emissions standards for which a waiver has been granted from the preemption provisions in section 209(a). States that decide to adopt California vehicle emissions standards may also choose to submit those standards to be included as a part of their SIP.

[232] The only coal-fired power plant in California is the 63 MW Argus Cogeneration facility in Trona, California.

TABLE V.C.1–1—EGU OZONE-SEASON EMISSIONS AND REDUCTION POTENTIAL (TONS)—2023—Continued

State	Baseline 2023 OS NO_X	Reduction potential (tons) for varying levels of technology inclusion		
		SCR optimization	SCR optimization + combustion control upgrades	SCR/SNCR optimization + combustion control upgrades
Wisconsin	6,321	7	7	26
Total	222,184	12,854	15,681	16,832

*The EPA shows reduction potential from state-of-the-art LNB upgrade as near-term emissions controls, but explains in section V.B and VI.A of this document that this reduction potential would not be implemented until 2024.

TABLE V.C.1–2—EGU OZONE-SEASON EMISSIONS AND REDUCTION POTENTIAL (TONS)—2026 *

State	Baseline 2026 OS NO_X	Reduction potential (tons) for varying levels of technology inclusion			
		SCR optimization	SCR optimization + combustion control upgrades	SCR/SNCR optimization + combustion control upgrades	SCR/SNCR optimization + combustion control upgrades + SCR/SNCR retrofits
Alabama	6,371	32	32	32	604
Arkansas	8,728	28	28	28	4,697
Illinois	6,644	70	70	230	1,281
Indiana	9,468	768	768	770	1,333
Kentucky	13,211	299	739	739	5,303
Louisiana	9,704	515	515	611	5,894
Maryland	901	51	51	59	59
Michigan	7,790	4	4	19	1,959
Minnesota	4,197	98	98	139	1,613
Mississippi	6,022	73	984	984	3,938
Missouri	18,612	7,339	7,339	7,497	11,231
Nevada	1,146	4	4	4	4
New Jersey	915	143	143	143	143
New York	3,977	64	64	64	589
Ohio	9,083	1,154	1,154	1,154	1,154
Oklahoma	10,259	199	890	890	5,968
Pennsylvania	8,362	352	352	452	1,204
Texas	39,684	909	909	1,142	15,980
Utah	9,930	7	7	7	7,338
Virginia	3,019	164	242	263	646
West Virginia	13,185	401	947	1,227	3,507
Wisconsin	5,016	7	7	26	623
Total	196,225	12,680	15,346	16,480	75,067

*The EPA shows all emissions reduction potential identified for assumed SCR retrofits in the Step 3 analytic year 2026, but explains in sections V.B and VI.A of this document that for Step 4 implementation this emissions reduction potential will be phased in during the 2026 and 2027 ozone season control periods.

2. Non-EGU or Industrial Source Emissions Reduction Potential

As described in the memorandum titled ''Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs,'' the EPA uses the 2019 emissions inventory, the list of emissions units estimated to be captured by the applicability criteria, the assumed control technologies that would meet the emissions limits, and information on control efficiencies and default cost/ton values from the CMDB, to estimate NO_X emissions reductions and costs for the year 2026. The estimates using the 2019 inventory and information from the CMDB identify proxies for emissions units, as well as emissions reductions, and costs associated with the assumed control technologies that would meet the final emissions limits. Emissions units subject to the final rule emissions limits may differ from those estimated in this assessment, and the estimated emissions reductions from and costs to meet the final rule emissions limits may also differ from those estimated in this assessment. The costs do not include monitoring, recordkeeping, reporting, or testing costs.

Table V.C.2–1 summarizes the industries, estimated emissions unit types, assumed control technologies, estimated annual costs (2016$), and estimated ozone season emissions reductions in 2026, and Table V.C.2–2 summarizes the estimated reductions by state.

TABLE V.C.2–1—BY INDUSTRY IN 2026, ESTIMATED EMISSIONS UNIT TYPES, ASSUMED CONTROL TECHNOLOGIES, ANNUAL COSTS (2016$), AND ESTIMATED EMISSIONS REDUCTIONS (OZONE SEASON TONS)

Industry/industries	Emissions unit type	Assumed control technologies that meet final emissions limits	Annual costs (2016$)	Ozone season emissions reductions
Pipeline Transportation of Natural Gas	Reciprocating Internal Combustion Engine	NSCR or Layered Combustion, Layered Combustion, SCR, NSCR.	385,463,197	32,247
Cement and Concrete Product Manufacturing.	Kiln	SNCR	10,078,205	2,573
Iron and Steel Mills and Ferroalloy Manufacturing.	Reheat Furnaces	LNB	3,579,294	408
Glass and Glass Product Manufacturing	Furnaces	LNB	7,052,088	3,129
Iron and Steel Mills and Ferroalloy Manufacturing.	Boilers	SCR, LNB + FGR	8,838,171	440
Metal Ore Mining			621,496	18
Basic Chemical Manufacturing			49,697,848	1,748
Petroleum and Coal Products Manufacturing.			5,128,439	147
Pulp, Paper, and Paperboard Mills			62,268,540	1,836
Solid Waste Combustors and Incinerators	Combustors or Incinerators	ANSCR or LN™ and SNCR	38,949,560	2,071
Totals			571,676,839	44,616

TABLE V.C.2–2—ESTIMATED EMISSIONS REDUCTIONS (OZONE SEASON TONS) BY UPWIND STATE IN 2026

State	2019 OS emissions *	OS NO_X reductions
AR	8,790	1,546
CA	16,562	1,600
IL	15,821	2,311
IN	16,673	1,976
KY	10,134	2,665
LA	40,954	7,142
MD	2,818	157
MI	20,576	2,985
MO	11,237	2,065
MS	9,763	2,499
NJ	2,078	242
NV [233]	2,544	0
NY	5,363	958
OH	18,000	3,105
OK	26,786	4,388
PA	14,919	2,184
TX	61,099	4,691
UT	4,232	252
VA	7,757	2,200
WV	6,318	1,649
Totals	302,425	44,616

* The 2019 OS season emissions are calculated as 5/12 of the annual emissions from the following two emissions inventory files: nonegu_SmokeFlatFile_2019NEI_POINT_20210721_controlupdate_13sep2021_v0 and oilgas_SmokeFlatFile_2019NEI_POINT_20210721_controlupdate_13sep2021_v0.

In Table V.C.2–3 by industry and emissions unit type, the EPA provides a summary of the control technologies applied and their average costs across all of the non-EGU emissions units. The average cost per ton values range from $939 to $14,595 per ton. Note that the average cost per ton values are in 2016 dollars and reflect simple averages and not a percentile or other representative cost values from a distribution of cost estimates.

TABLE V.C.2–3—BY INDUSTRY, EMISSIONS UNIT TYPE, ASSUMED CONTROL TECHNOLOGIES, AND ESTIMATED AVERAGE COST PER TON BY CONTROL TECHNOLOGY ACROSS ALL NON-EGU EMISSIONS UNITS

Industry/industries	Emissions unit type	Assumed control technologies that meet final emissions limits	Average cost/ton values (2016$)
Pipeline Transportation of Natural Gas	Reciprocating Internal Combustion Engine	NSCR or Layered Combustion, Layered Combustion, SCR, NSCR.	4,981
Cement and Concrete Product Manufacturing	Kiln	SNCR	1,632

[233] We are not aware of existing non-EGU emissions units in Nevada that meet the applicability criteria for non-EGUs in the final rule. If any such units in fact exist, they would be subject to the requirements of the rule just as in any other state. In addition, any new emissions unit in Nevada that meets the applicability criteria in the final rule will be subject to the final rule's requirements. *See* section III.B.1.d.

TABLE V.C.2–3—BY INDUSTRY, EMISSIONS UNIT TYPE, ASSUMED CONTROL TECHNOLOGIES, AND ESTIMATED AVERAGE COST PER TON BY CONTROL TECHNOLOGY ACROSS ALL NON-EGU EMISSIONS UNITS—Continued

Industry/industries	Emissions unit type	Assumed control technologies that meet final emissions limits	Average cost/ton values (2016$)
Iron and Steel Mills and Ferroalloy Manufacturing	Reheat Furnaces	LNB	3,656
Glass and Glass Product Manufacturing	Furnaces	LNB	939
Iron and Steel Mills and Ferroalloy Manufacturing	Boilers	SCR or LNB + FGR	8,369
Metal Ore Mining			14,595
Basic Chemical Manufacturing			11,845
Petroleum and Coal Products Manufacturing			14,582
Pulp, Paper, and Paperboard Mills			14,134
Solid Waste Combustors and Incinerators	Combustors or Incinerators	ANSCR or LN™ and SNCR	7,836
Overall Average Cost/Ton			5,339

Refer to the memorandum titled ''Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs'' for additional estimates—including by industry and by state. These estimates are proxy estimates, and the EPA also did not prepare detailed engineering analyses for the industries, facilities, and individual emissions units identified for the final rule. Emissions units subject to the final rule emissions limits may differ from those estimated in this assessment, and the estimated emissions reductions from and costs to meet the final rule emissions limits may also differ from those estimated in this assessment.

Comment: Regarding the marginal cost threshold of $7,500/ton used to assess potential emissions reductions in the non-EGU screening assessment prepared for proposal, commenters raised a range of questions, including (1) why the EPA used a marginal cost threshold that is much higher than the $2,000/ton threshold used in the 2021 Revised CSAPR Update Rule, (2) why the EPA used a ''one size fits all'' approach for addressing the estimated cost and actual emissions reductions achievable, particularly for existing sources of NO_X emissions, (3) why the EPA set a $7,500/ton marginal cost threshold for all non-EGUs, despite acknowledging the heterogeneity of industry, emissions unit types and control options and failing to consider the actual costs associated with achieving the proposed reductions at different types of emissions units in order to artificially inflate the marginal cost threshold and to justify otherwise cost-prohibitive NO_X control technologies. Commenters also stated that controls for their industry are not cost-effective using the EPA's presumptive value of $7,500/ton and that the value may not be technically feasible to apply to existing sources that would have to retrofit controls.

Response: The EPA notes that the primary purpose of the *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* (non-EGU screening assessment) was to identify potentially impactful industries and emissions unit types for further evaluation.[234] In the non-EGU screening assessment memorandum we presented an analytical framework to further analyze potential emissions reductions and costs and included proxy estimates for 2026.

As noted in section V.D. of this document, at proposal the EPA found that based on data available at that time and for the purposes of the non-EGU screening assessment, it appeared that a $7,500 marginal cost-per-ton threshold could be used as a proxy to identify cost-effective emissions control opportunities. Also, the $7,500 marginal cost-per-ton threshold is higher than the cost-per-ton value used in the Revised Cross-State Air Pollution Rule Update because that rulemaking assessed significant contribution for the less protective 2008 ozone NAAQS, and it is reasonable when assessing significant contribution associated with the more protective 2015 ozone NAAQS, that a potentially more costly universe of emissions controls and related potential reductions should be included in the analysis.[235] Similar to the role of cost-effectiveness thresholds the EPA uses at Step 3 to evaluate EGU emissions control opportunities, this threshold is not intended to represent the maximum cost any facility may need to expend but is rather intended to be a representative figure for evaluating technologies to allow for a relative comparison between different levels of control stringency. The EPA's potential cost threshold for non-EGU controls at proposal was intended to serve a similar representative purpose. Based on the EPA's updated analysis for this final rule, the EPA recognizes that the $7,500/ton threshold does not reflect the full range of cost-effectiveness values that are likely present across the many different types of non-EGU industries and emissions units assessed.

While the potentially impactful industries (identified in Step 1 of the analytical framework presented in the non-EGU screening assessment) were directly used, the proxy estimates for emissions unit types, emissions reductions, and costs from the non-EGU screening assessment were not directly used to establish applicability thresholds and emissions limits in the proposal. To further evaluate the impactful industries and emissions unit types and establish the proposed emissions limits, the EPA reviewed RACT rules, NSPS rules, NESHAP rules, existing technical studies (*e.g.,* Ozone Transport Commission, Technical Information Oil and Gas Sector Significant Stationary Sources of NO_X Emissions, October 17, 2012), rules in approved SIP submittals, consent decrees, and permit limits.[236]

[234] The non-EGU screening assessment memorandum is available in the docket here: *https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150*.

[235] As the amount of air pollution that is allowed in the ambient air is reduced (i.e., when a NAAQS is revised), it is reasonable to expect that further emissions reductions may be necessary to bring areas into attainment with that more protective standard. At the same time, the available remaining emissions reduction opportunities will likely have become more costly compared to a prior period, because other CAA requirements, including such as earlier transport rules, will have consumed those emissions reduction opportunities that were the least costly. The EPA noted this same possibility in the original CSAPR rulemaking, *see* 76 FR 48210.

[236] This review is detailed in the Final Non-EGU Sectors TSD available in the docket here: *https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145*.

D. Assessing Cost, EGU and Non-EGU NO_X Reductions, and Air Quality

To determine the emissions that are significantly contributing to nonattainment or interfering with maintenance, the EPA applied the multi-factor test to EGUs and non-EGUs separately, considering for each the relationship of cost, available emissions reductions, and downwind air quality impacts. Specifically, for each sector, the EPA finalizes a determination regarding the appropriate level of uniform NO_X control stringency that would collectively eliminate significant contribution to downwind nonattainment and maintenance receptors. Based on the air quality results presented in this section, we find that the emissions control strategies that were identified and evaluated in sections V.B and V.C of this document and found to be both cost-effective and feasible, deliver meaningful air quality benefits through projected reductions in ozone levels across the linked downwind nonattainment and maintenance receptors in the relevant analytic years 2023 and 2026. Further, EPA finds the emissions control strategies in upwind states that would deliver these benefits to be widely available and in use at many other similar EGU and non-EGU facilities throughout the country, particularly in those areas that have historically or now continue to struggle to attain and maintain the 2015 ozone NAAQS. Applying these emissions control strategies on a uniform basis across all linked upwind states continues to constitute an efficient and equitable solution to the problem of allocating upwind-state responsibility for the elimination of significant contribution. This approach continues to effectively address the ''thorny'' causation problem of interstate pollution transport for regional-scale pollutants like ozone that transport over large distances and are affected by the vagaries of meteorology. *EME Homer City,* 572 U.S. at 514–16. It requires the most impactful sources in each state that has been found to contribute to ozone problems in other states to come up to minimum standards of environmental performance based on demonstrated NO_X pollution-control technology. *Id.* at 519. When the effects of these emissions reductions are assessed collectively across the hundreds of EGU and non-EGU industrial sources that are subject to this rule, the cumulative improvements in ozone levels at downwind receptors, while they may vary to some extent, are both measurable and meaningful and will assist downwind areas in attaining and maintaining the 2015 ozone NAAQS.

In addition to the findings of cost-effectiveness, feasibility and widespread availability that support EPA's identification of the appropriate level of emissions-control stringency at Step 3 discussed in sections V.B and V.C, the findings regarding air quality improvement in this section—as in prior transport rules—are a central component of our Step 3 analytic findings as to the definition of ''significant contribution.'' EPA's assessment of air quality improvement for all of the emissions control strategies included shows continued air quality improvement with each additional control strategy measure. Within the group of selected control strategies for EGUs and non-EGUs no clear ''knee-in-the-curve'' is evident; *i.e.,* there is no point at which there is a noticeable decline in the rate of air quality improvement up through the control stringency level selected. However, if EPA were to go beyond the selected control stringency through inclusion of additional EGU or non-EGU NO_X mitigation technologies for the covered sources and unit-types that are, at least on the record of this action, not widely available, uncertain or untested, and/or far more costly, a ''knee-in-the-curve'' does materialize, where the incremental air quality benefit per dollar spent per ton on mitigation measures plateaus even as costs increase dramatically. In the Revised CSAPR Update, EPA explained that a knee in the curve ''is not on its own a justification for not requiring reductions beyond that point,'' 86 FR 23107, but does indicate that it is a useful indicator for informing potential stopping points. The observation that no ''knee-in-the-curve'' materializes at the stringency levels up through that selected by EPA supports EPA's identified control stringency.

Further, as the Supreme Court has explained, ''while EPA has a statutory duty to avoid over-control, the Agency also has a statutory obligation to avoid 'under-control,' *i.e.,* to maximize achievement of attainment downwind.'' 572 U.S. at 523. While the ultimate purpose of the good neighbor provision is to eliminate significant contribution and not necessarily to resolve downwind areas' nonattainment and maintenance problems, we have evaluated the expected attainment status at each identified receptor as we examine the air quality effects of the different emissions control strategies identified. As discussed further in this section, the EPA notes that multiple receptors shift into projected attainment status or shift from projected nonattainment to maintenance status up through the stringency level ultimately selected by EPA. (And all receptors show improvement in air quality even if their status does not change.) These analytic findings at Step 3 cement EPA's identification of the selected EGU and non-EGU mitigation measures as the appropriate control stringency to fulfill its statutory obligation to eliminate significant contribution for the 2015 ozone NAAQS for the covered states. The EPA also evaluated whether the final rule resulted in possible over-control scenarios by evaluating if an upwind state is linked solely to downwind air quality problems that could have been resolved at a lower cost threshold, or if an upwind state could have reduced its emissions below the 1 percent of NAAQS air quality contribution threshold at a lower cost threshold. The Agency finds no overcontrol from this rule. See section V.D.4 of this document.

1. EGU Assessment

For EGUs, the EPA examined the emissions reduction potential associated with each EGU emissions control technology (presented in section V.C.1 of this document) and its impact on the air quality at downwind receptors. Specifically, EPA identified and assessed the projected average air quality improvements relative to the base case and whether these improvements are sufficient to shift the status of receptors from projected nonattainment to maintenance or from maintenance to attainment. Combining these air quality factors, costs, and emissions reductions, the EPA identified a control stringency for EGUs that results in substantial air quality improvement from emissions controls that are available in the timeframe for which air quality problems at downwind receptors persist. For all affected jurisdictions, this control stringency reflects, at a minimum, the optimization of existing post-combustion controls and installation of state-of-the-art NO_X combustion controls, which are widely available at a representative cost of $1,800 per ton. EPA's evaluation also shows that the effective emissions rate performance across affected EGUs consistent with realization of these mitigation measures does not over-control upwind states' emissions relative to either the downwind air quality problems to which they are linked at Step 1 or the 1 percent contribution threshold that triggers further evaluation at Step 3 of the 4-step framework for the 2015 ozone NAAQS.

Similarly, the EPA also identified installation of new SCR post-combustion controls at coal steam sources greater than or equal to 100 MW and for a more limited portion of the oil/gas steam fleet that had higher levels of emissions as components of the required control stringency. These SCR retrofits are widely available starting in the 2026 ozone season at $11,000 and $7,700 per ton respectively. For all but 3 of the affected states (Alabama, Minnesota, and Wisconsin, which are no longer linked in 2026 at Steps 1 and 2 in EPA's base case air quality modeling for this final rule), EPA's evaluation shows that the effective emissions rate performance across EGUs consistent with the full realization of these mitigation measures does not over-control upwind states' emissions in 2026 relative to either the downwind air quality problems to which they are linked at Step 1 or the 1 percent contribution threshold that triggers further evaluation at Step 3 of the 4-step framework for the 2015 ozone NAAQS (*see* the Ozone Transport Policy Analysis Final Rule TSD for details).

To assess downwind air quality impacts for the nonattainment and maintenance receptors identified in section IV.D of this document, the EPA evaluated the air quality change at that receptor expected from the progressively more stringent upwind EGU control stringencies that were available for that time period in upwind states linked to that receptor. This assessment provides the downwind ozone improvements for consideration and provides air quality data that is used to evaluate potential over-control situations.

To assess the air quality impacts of the various control stringencies at downwind receptors for the purposes of Step 3, the EPA evaluated changes resulting from the emissions reductions associated with the identified emissions controls in each of the upwind states, as well as assumed corresponding reductions of similar stringency in the downwind state containing the receptor to which they are linked. By applying these emissions reductions to the state containing the receptor, the EPA assumes that the downwind state will implement (if it has not already) an emissions control stringency for its sources that is comparable to the upwind control stringency identified here. Consequently, the EPA is accounting for the downwind state's "fair share" of the responsibility for resolving a nonattainment or maintenance problem as a part of the over-control evaluation.[237]

For this assessment, the EPA used an ozone air quality assessment tool (ozone AQAT) to estimate downwind changes in ozone concentrations related to upwind changes in emissions levels. The EPA focused its assessment on the years 2023 and 2026 as they pertain to the last years for which ozone season emissions data can be used for purposes of determining attainment for the Moderate (2024) and Serious (2027) attainment dates. For each EGU emissions control technology, the EPA first evaluated the magnitude of the change in ozone concentrations at the nonattainment and maintenance receptors for each relevant year (*i.e.,* 2023 and 2026). Next, the EPA evaluated whether the estimated change in concentration would resolve the receptor's nonattainment or maintenance concern by lowering the average or maximum design values, respectively, below 71 ppb. For a complete set of estimates, see the Ozone Transport Policy Analysis Final Rule TSD or the ozone AQAT Excel file.

For 2023, the EPA evaluated potential air quality improvements at the downwind receptors outside of California associated with available EGU emissions control technologies in that timeframe. The EPA determined for the purposes of Step 3 that the average air quality improvement at the receptors relative to the engineering analytics base case was 0.06 ppb for emissions reductions commensurate with optimization of existing SCRs/SNCRs and combustion control upgrades. The EPA determined for the purposes of Step 3 that no receptors switch from maintenance to attainment or from nonattainment to maintenance with these mitigation strategies in place. Table V.D.1–1 summarizes the results of EPA's Step 3 evaluation of air quality improvements at these receptors using AQAT.

For 2026, the EPA determined that the average air quality improvement at these receptors relative to the engineering analytics base case was 0.47 ppb for emissions reductions commensurate with optimization of existing SCRs/SNCRs, combustion control upgrades, and new post-combustion control (SCR and SNCR) retrofits at eligible units are assumed to be implemented. The EPA determined for the purposes of Step 3 that in 2026, all but one of the receptors are expected to remain nonattainment or maintenance across these control stringencies, with one receptor in Larimer County, Colorado (Monitor 080690011), switching from maintenance to attainment and two receptors (one in Fairfield County, Connecticut (Monitor 90013007), and one in Galveston, Texas (Monitor ID 481671034)) switching from nonattainment to maintenance with these mitigation strategies in place.[238] Table V.D.1–2 summarizes the results of EPA's Step 3 evaluation of air quality improvements at the receptors included in the AQAT analysis. For more information about how this assessment was performed and the results of the analysis for each receptor, refer to the Ozone Transport Policy Analysis Final Rule TSD and to the Ozone AQAT included in the docket for this rule.

[237] For EGUs, this analysis for the Connecticut receptors shows no EGU reduction potential in Connecticut from the emissions reduction measures identified given that state's already low-emitting fleet; however, EGU reductions were identified in Colorado and these reductions were included in the over-control analysis.

[238] As in prior rules, for the purpose of defining significant contribution at Step 3, the EPA evaluated air quality changes resulting from the application of the emissions reductions in only those states that are linked to each receptor as well as the state containing the receptor. By applying reductions to the state containing the receptor, the EPA ensures that it is accounting for the downwind state's fair share. This method holds each upwind state responsible for its fair share of the downwind problems to which it is linked. Reductions made by other states to address air quality problems at other receptors do not increase or decrease this share. The air quality impacts on design values that reflect the emissions reductions in all linked states action are further discussed in sections V.D.3 and V.D.4 of this document.

TABLE V.D.1–1—AIR QUALITY AT THE RECEPTORS IN 2023 FROM EGU EMISSIONS CONTROL TECHNOLOGIES [a]

Monitor ID No.	State	County	Average DV (ppb)		Max DV (ppb)	
			Baseline (engineering analysis)	SCR/SNCR optimization + LNB upgrade	Baseline (engineering analysis)	SCR/SNCR optimization + LNB upgrade
40278011	Arizona	Yuma	70.36	70.34	72.05	72.04
80350004	Colorado	Douglas	71.12	71.10	71.71	71.70
80590006	Colorado	Jefferson	72.63	72.61	73.32	73.31
80590011	Colorado	Jefferson	73.29	73.27	73.89	73.87
80690011	Colorado	Larimer	70.79	70.78	71.99	71.98
90010017	Connecticut	Fairfield	71.62	71.56	72.22	72.16
90013007	Connecticut	Fairfield	72.99	72.90	73.89	73.80
90019003	Connecticut	Fairfield	73.32	73.25	73.62	73.55
90099002	Connecticut	New Haven	70.61	70.51	72.71	72.61
170310001	Illinois	Cook	68.13	68.11	71.82	71.80
170314201	Illinois	Cook	67.92	67.88	71.41	71.37
170317002	Illinois	Cook	68.47	68.37	71.27	71.17
350130021	New Mexico	Dona Ana	70.83	70.82	72.13	72.12
350130022	New Mexico	Dona Ana	69.73	69.72	72.43	72.42
350151005	New Mexico [b]	Eddy				
350250008	New Mexico	Lea				
480391004	Texas	Brazoria	70.59	70.52	72.69	72.62
481210034	Texas	Denton	69.93	69.88	71.73	71.68
481410037	Texas	El Paso	69.82	69.81	71.43	71.41
481671034	Texas	Galveston	71.82	71.70	73.13	73.01
482010024	Texas	Harris	75.33	75.25	76.93	76.85
482010055	Texas	Harris	71.19	71.10	72.20	72.10
482011034	Texas	Harris	70.32	70.25	71.52	71.45
482011035	Texas	Harris	68.01	67.94	71.52	71.45
490110004	Utah	Davis	71.88	71.87	74.08	74.07
490353006	Utah	Salt Lake	72.48	72.47	74.07	74.06
490353013	Utah	Salt Lake	73.21	73.20	73.71	73.70
550590019	Wisconsin	Kenosha	70.75	70.65	71.65	71.55
551010020	Wisconsin	Racine	69.59	69.46	71.39	71.25
551170006	Wisconsin	Sheboygan	72.64	72.46	73.54	73.36
Average AQ Change Relative to Base (ppb)						0.06
Total PPB Change Across All Receptors Relative to Base [c]						1.58

Table Notes:

[a] The EPA notes that the design values reflected in tables V.D.1–1 and –2 correspond to the engineering analysis EGU emissions inventory that was used in AQAT to determine state-level baseline emissions and reductions at Step 3. These tools are discussed in greater detail in the Ozone Transport Policy Analysis Final Rule TSD.

[b] New Mexico Eddy and Lea monitors have no values in tables V.D.1–1 and 1–2 as EPA does not have calibration factors for these monitors as no contributions were calculated for them from the proposal AQ modeling

[c] The cumulative ppb change only shows the aggregate change across all problematic receptors (some of which are located within close proximity to one another) in this part of the Step 3 analysis. Section VIII of this document provides a more complete picture of the air quality impacts of the final rule.

TABLE V.D.1–2—AIR QUALITY AT RECEPTORS IN 2026 FROM EGU EMISSIONS CONTROL TECHNOLOGIES

Monitor ID No.	State	County	Average DV (ppb)		Max DV (ppb)	
			Baseline (engineering analysis)	SCR/SNCR optimization + LNB upgrade + SCR/SNCR retrofit	Baseline (engineering analysis)	SCR/SNCR optimization + LNB upgrade + SCR/SNCR retrofit
40278011	Arizona	Yuma	69.87	69.84	71.47	71.44
80590006	Colorado	Jefferson	71.70	71.36	72.30	71.95
80590011	Colorado	Jefferson	72.06	71.59	72.66	72.19
80690011	Colorado	Larimer	69.84	69.54	71.04	70.73
90013007	Connecticut	Fairfield	71.25	70.98	72.06	71.78
90019003	Connecticut	Fairfield	71.58	71.34	71.78	71.54
350130021	New Mexico	Dona Ana	70.06	69.89	71.36	71.19
350130022	New Mexico	Dona Ana	69.17	69.00	71.77	71.60
350151005	New Mexico	Eddy				
350250008	New Mexico	Lea				
480391004	Texas	Brazoria	69.89	68.96	72.02	71.06
481671034	Texas	Galveston	71.29	70.02	72.51	71.22
482010024	Texas	Harris	74.83	73.86	76.45	75.46
490110004	Utah	Davis	69.90	69.34	72.10	71.52
490353006	Utah	Salt Lake	70.50	69.96	72.10	71.55
490353013	Utah	Salt Lake	71.91	71.45	72.31	71.84
551170006	Wisconsin	Sheboygan	70.83	70.51	71.73	71.41
Average AQ Change Relative to Base (ppb)						0.47
Total PPB Change Across All Receptors Relative to Base (ppb)						7.04

Figures 1 and 2 to section V.D.1 of this document, included in Appendix I of the Ozone Transport Policy Analysis Final Rule TSD available in the docket for this rulemaking, illustrate the air quality improvement relative to the estimated representative cost associated with the previously identified emissions control technologies. The graphs show improving air quality at the downwind receptors as emissions reductions commensurate with the identified control technologies are assumed to be implemented. Figure 1 to section V.D.1 of this document reflects emissions reductions commensurate with optimization of existing SNCRs and SCRs. Figure 2 to section V.D.1 of this document reflects emissions reductions commensurate with installation of new post combustion controls (mainly SCRs) layered on top of the emissions reduction potential from the technologies represented in Figure 1 to section V.D.1 of this document. The graphic, and underlying AQAT receptor-by-receptor analysis demonstrates that air quality continues to improve at downwind receptors as EPA examines increasingly stringent EGU NO_X control technologies. While all major technology breakpoints identified in sections V.B and V.C of this document show continued air quality improvements at problematic receptors and at cost and technology levels that are commensurate with mitigation strategies that are proven to be widely available and implemented, EPA's quantification and application of those breakpoints reflect certain exclusions to: (1) preserve this consistency with widely observed mitigation measures in states, and (2) remove any retrofit assumptions at marginal units that would have much higher dollar per ton representative cost and little or no air quality benefit. For instance, the EPA does not define the SCR retrofit breakpoint ($11,000 per ton) to include retrofit application at steam units less than 100 MW or at oil/gas steam units emitting at less than 150 tons per ozone season. The emissions reductions from these potential categories of measures are small and do not constitute additional ''breakpoints'' in EPA's estimation. They would entail much higher dollar per ton costs, going beyond what is widely observed in the fleet. This careful calibration of technology breakpoints through exclusion of measures that are clearly not cost-effective in terms of air quality benefit allows for the identification of an EGU uniform control stringency that is an appropriate reflection of those readily available and widely implemented emissions reduction strategies that will have meaningful downwind air quality impact.

Moreover, these technologies (and representative cost) are demonstrated ozone pollution mitigation strategies that are widely practiced across the EGU fleet and are of comparable stringency to emissions reduction measures that many downwind states have already instituted. The coal SCR retrofit measures driving the majority of the emissions reductions in this action not only reflect industry best practice, but they also reflect prevailing practice among EGUs. More than 66 percent of the existing coal capacity already has this technology in place. For nearly 25 years, all new coal-fired EGUs that commenced construction have had SCR (or equivalent emissions rates). The 1997 proposed amendments to subpart Da revised the NO_X standard based on the use of SCR. The NO_X SIP Call (promulgated in 1998) established emissions reduction requirements premised on extensive SCR installation (142 units) and incentivized well over 40 GWs of SCR retrofit in the ensuing years.[239] Similarly, the Clean Air Interstate Rule established emissions reductions requirements in 2006 that assumed SCR would be installed on another 58 units (15 GW) in the ensuing years among just 10 states, and an even greater volume of capacity chose SCR retrofit measures in the wake of finalizing that action.[240]

Basing emissions reduction requirements for EGUs on SCR retrofits is also consistent with regulatory approaches adopted by states, which—particularly in downwind areas more impacted by ozone transport contribution from upwind state emissions—have already adopted SCR-based standards as part of stringent NO_X control programs. Regulatory programs that impose stringent RACT requirements on all major power plants and Lowest Achievable Emission Rate (LAER) standards on all new major sources of NO_X have resulted in remaining coal-fired generating resources in states along the Northeast Corridor such as Connecticut, Delaware, New Jersey, New York, and Massachusetts all being retrofitted with SCR.[241] The Maryland Code of Regulations requires coal-fired sources to operate existing SCR controls or install SCR controls by specified dates.[242] Programs like North Carolina's Clean Smokestacks Act and Colorado's Clean Air, Clean Jobs Act have also required or prompted SCR retrofits on units.[243] Unit-level BART requirements for the first Regional Haze planning period also determined SCR retrofits (and corresponding emissions rates) were cost-effective controls for a variety of sources in the U.S.[244]

As shown in Figure 1 to section V.D.1 of this document,[245] the majority of EGU emissions reduction potential and associated air quality improvements estimated for 2023 occurs from optimization of existing SCRs, with some additional reductions from installation of state-of-the-art combustion controls at the same representative cost threshold. At the slightly higher representative cost threshold of $1,800 per ton, there is some additional air quality improvement from optimization of existing SNCRs. These measures taken together represent the control stringency at which near-term incremental EGU NO_X reduction potential and corresponding downwind ozone air quality improvements are maximized. This evaluation shows that EGU NO_X reductions for each of the near-term emissions control technologies are available at reasonable cost and that these reductions provide meaningful improvements in downwind ozone concentrations at the identified nonattainment and maintenance receptors. Figure 1 to section V.D.1 of this document[246] highlights (1) the continuous connection between identified emissions reduction potential and downwind air quality improvement across the range of near-term mitigation measures assessed, and (2) the cost-effective availability of these reductions and corresponding air quality improvements.

Additional considerations that are unique to EGUs provide additional support for EPA's determination to include SCR and SNCR optimization as part of the identified near-term control stringency, including:

[239] 63 FR 57448.

[240] 71 FR 25345.

[241] EPA–HQ–OAR–2020–0272. Comment letter from Attorneys General of NY, NJ, CT, DE, MA.

[242] COMAR 26.11.38 (control of NO_X Emissions from Coal-Fired Electric Generating Units).

[243] *https://www.epa.gov/system/files/documents/2021-09/table-3-30-state-power-sector-regulations-included-in-epa-platform-v6-summer-2021-refe.pdf.*

[244] *See* table 3–35 BART regulations in EPA IPM documentation available at *https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference-case.*

[245] Included in Appendix I of the Ozone Transport Policy Analysis Final Rule TSD, which is available in the docket for this rulemaking.

[246] Included in Appendix I of the Ozone Transport Policy Analysis Final Rule TSD, which is available in the docket for this rulemaking.

- these controls are already installed and available for operation on these units;
- they are on average already partially operating, but not necessarily optimized;
- the reductions are available in the near-term (during ozone seasons when the problematic receptors are projected to persist), including by the 2023 ozone season aligned with the Moderate area attainment date; and
- these sources are already covered under the existing CSAPR NO_X Ozone Season Group 2 or Group 3 Trading Programs or the Acid Rain Program and thus have the monitoring, reporting, recordkeeping, and all other necessary elements of compliance with the trading program already in place.

The majority of EGU emissions reduction potential and associated air quality improvements estimated to start in 2026 occur from retrofitting uncontrolled steam sources with post-combustion controls. At the representative cost threshold of $11,000 per ton, there are significant additional air quality improvements from emissions reductions commensurate with installation of new SCRs and SNCRs. These measures taken together with the near-term emissions reduction measures described previously represent the level of control stringency in 2026 at which incremental EGU NO_X reduction potential and corresponding downwind ozone air quality improvements are maximized. This evaluation shows that EGU NO_X reductions for each of the emissions control technologies are available at reasonable cost and that these reductions can provide improvements in downwind ozone concentrations at the identified nonattainment and maintenance receptors.

The EPA finds that the control stringency that reflects optimization of existing SCRs and SNCRs, installation of state-of-the-art combustion controls, and the retrofitting of new post combustion controls at the coal and oil/gas steam capacity described previously is projected to result in nearly 73,000 tons of NO_X reduction (approximately 40 percent of the 2026 baseline level) for the 19 linked states in 2026 subject to a FIP for EGUs, which will deliver notable air quality improvements across all transport-impacted receptors and assist in fully resolving one downwind air quality receptor for the 2015 ozone NAAQS. Figure 2 to section V.D.1 of this document [247] demonstrates the continuous connection between identified emissions reduction potential and downwind air quality improvement across the range of mitigation measures assessed in 2026. At no point do the additional emissions mitigation measures examined here fail to produce corresponding downwind air quality improvements.

The EPA is determining that the appropriate EGU control stringency is commensurate with the full operation of all existing post-combustion controls (both SCRs and SNCRs) and state-of-the-art combustion control upgrades for those states linked to downwind nonattainment or maintenance receptors in 2023. For those states also linked in 2026, the EPA is determining that the appropriate EGU control stringency also includes emissions reductions commensurate with the retrofit of SCR at coal steam units of 100 MW or greater capacity (excepting circulating fluidized bed units), new SNCR on coal steam units of less than 100 MW capacity and circulating fluidized bed units, and SCR on oil/gas steam units greater than 100 MW that have historically emitted at least 150 tons of NO_X per ozone season.

As noted previously in section V.B of this document and in the EGU NO_X Mitigation Strategies Final Rule TSD, the EPA considered other methods of identifying mitigation measures (*e.g.,* SCRs on smaller units, combustion control upgrades on combustion turbines, SCRs on combined cycle and simple cycle combustion turbines). The emissions reductions from these potential categories of measures do not constitute additional ''technology breakpoints'' in EPA's estimation, but rather reflect a different tier of assessment where further mitigation measures are based on inclusion of smaller and/or different generator-type units (rather than different pollution control technologies). Emissions reductions from these measures are relatively small and would entail much higher dollar per ton costs, going beyond what is widely observed in the fleet. Although these additional measures are not included in EPA's technology breakpoint analysis discussed in this section, the EPA did analyze the cost, potential reductions, and air quality impact of these additional measures to affirm that they do not merit inclusion in the final stringency for this action. That analysis shows the potential emissions reductions and air quality improvements from these additional measures occur beyond a notable ''knee-in-the-curve'' breakpoint. In other words, there are very little additional emissions reductions and air quality improvement at problematic receptors, and the cost associated with these measures increases substantially on a dollar per ton basis. The graphic capturing this effect (located in Appendix I of the Ozone Transport Policy Analysis Final Rule TSD) illustrates the significant decline in cost-effectiveness of reductions if these measures had been included in EPA's final stringency.[248]

2. Non-EGU Assessment

Using a 2019 emissions inventory, the list of emissions units estimated to be captured by the applicability criteria, the assumed control technologies that would meet the emissions limits, and information on control efficiencies and default cost/ton values from the control measures database, the EPA estimated NO_X emissions reductions and costs for the year 2026. Given the EPA's conclusion that the 2026 ozone season is the earliest date by which the required controls can be installed across the identified non-EGU industries, the EPA assessed the effects of these controls in 2026 under its multi-factor test. In the assessment, we matched emissions units by Source Classification Code (SCC) from the inventory to the applicable control technologies in the CMDB. We modified SCC codes as necessary to match control technologies to inventory records. For additional details about the steps taken to estimate emissions units, emissions reductions, and costs, see the memorandum titled ''Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs'' available in the docket. The estimates using the 2019 inventory and information from the CMDB identify proxies for emissions units, as well as emissions reductions, and costs associated with the assumed control

[247] Included in Appendix I of the Ozone Transport Policy Analysis Final Rule TSD, which is available in the docket for this rulemaking.

[248] This is not to discount the potential effectiveness of these or other NO_X mitigation strategies outside the context of this rulemaking, which addresses regional ozone transport on a nationwide basis based on the present record. States and local jurisdictions may find such measures particularly impactful or necessary in the context of local attainment planning or other unique circumstances. Further, while the EPA finds on the present record that this rule is a complete remedy to the problem of interstate transport for the 2015 ozone NAAQS for the covered states, the EPA has in the past recognized that circumstances may arise after the promulgation of remedies under CAA section 110(a)(2)(D)(i)(I) in which the exercise of further remedial authority against specific stationary sources or groups of sources under CAA section 126 may be warranted. *See* Response to Clean Air Act Section 126(b) Petition From Delaware and Maryland, 83 FR 50444, 50453–54 (Oct. 5, 2018).

technologies that would meet the final emissions limits. Emissions units subject to the final rule emissions limits may differ from those estimated in this assessment, and the estimated emissions reductions from, and costs to meet, the final rule emissions limits may also differ from those estimated in this assessment. The costs do not include monitoring, recordkeeping, reporting, or testing costs.

After reviewing public comments and updating some of the data used to provide an accurate assessment of the likely potential emissions reductions that could be achieved from the identified emissions units in the industries analyzed for proposal, the EPA finds that in general, these emissions reductions (with some modifications from proposal) are necessary to eliminate significant contribution at Step 3. The EPA's use of the analytical framework presented in the non-EGU screening assessment to identify potentially impactful industries and emissions unit types in the proposal remains valid. The EPA's criteria were intended to identify industries and emissions unit types that on a broad scale impact multiple receptors to varying degrees. The EPA focused its non-EGU screening assessment on (1) emissions and potential emissions reductions from these industries and emissions units and (2) the potential impact that emissions reductions from those industries and emissions units could deliver to the receptors.

While commenters criticized the analytical framework in the non-EGU screening assessment for assuming potentially unachievable emissions reductions at Step 3, or for not corresponding to a precise list of emissions units that would be covered at Step 4, these comments did not offer an alternative methodology for the Step 3 analysis to identify those industries and emissions units that potentially have the greatest impact and therefore should be scrutinized more closely for emissions reduction opportunities.[249] Further, contrary to some commenters' assertions, the EPA's assessment did not result in an unbounded scope of regulation of industrial sources. Of the approximately 40 industries defined by North American Industry Classification System codes the EPA analyzed, only seven industries were identified as having emissions and potential emissions reduction opportunities that met the EPA's air quality criteria for further assessment.

At proposal, the EPA found that based on data available at that time and for the purposes of the screening assessment, it appeared that a $7,500 marginal cost-per-ton threshold could be used as a proxy to identify cost-effective emissions control opportunities. Similar to the role of cost-effectiveness thresholds the EPA uses at Step 3 to evaluate EGU emissions control opportunities, this threshold is not intended to represent the maximum cost any facility may need to expend but is rather intended to be a representative figure for evaluating technologies to allow for a relative comparison between different levels of control stringency. For example, in the EGU analysis, the $11,000/ton average cost threshold for an SCR retrofit represents a range of SCR retrofit costs for units for which the 90th percentile cost-per-ton is roughly $21,000. See section V.B.a of this document. The EPA's potential cost threshold for non-EGU controls at proposal was intended to serve a similar representative purpose. We respond briefly to comments regarding the use of the $7,500/ton threshold in section V.C of this document. Comments regarding the screening assessment are further addressed in section 2.2 of the response to comments document in the docket.

Based on the EPA's updated analysis for this final rule, the EPA recognizes that the $7,500/ton threshold does not reflect the full range of cost-effectiveness values that are likely present across the many different types of non-EGU industries and emissions units assessed. However, the EPA nonetheless finds that, with some adjustments from proposal, the overall mix of emissions controls it identified at proposal is appropriate to eliminate significant contribution to nonattainment or interference with maintenance in downwind areas. In the final analysis, we find that the average cost-per-ton of emissions reductions across all non-EGU industries in this rule generally ranges from approximately $939/ton to $14,595/ton, with an overall average of approximately $5,339/ton. *See* memorandum titled ''Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs,'' available in the docket.

Nonetheless, overall the EPA finds that the range of cost-effectiveness values for non-EGU industries and emissions units compares favorably with the values used to evaluate EGUs. As discussed in the preceding paragraphs, the representative cost for EGUs to retrofit SCR is $11,000/ton. This reflects a range of cost estimates, with $20,900/ton reflecting the 90th percentile of units (see section V.B.a of this document). The higher end of the estimated average cost range for certain non-EGU industrial emissions units is also in that range. While specific emissions units may have higher costs associated with installing pollution control technologies than other similar unit types, this does not in itself undermine the Agency's conclusion that a level of emissions control associated with a specific emissions limit or control technology is appropriate to require across the linked upwind state region, in light of the overall emissions reductions and air quality benefits at downwind receptors that those controls are projected to deliver.

We note that the non-EGU control cost estimates in this final rule were based on historical actual emissions. This can affect the presentation of cost-per-ton values at the unit level, and it would not be appropriate to abandon uniform control stringency among like units in the covered industries across or within upwind states based on such cost differentials.

The EPA finds it appropriate to require a uniform level of emissions control across similar emissions unit types to, among other things, prevent two potential outcomes related to shifting production, either between units within the same facility or between units at different facilities. First, if some units were exempted from control requirements because of historically low actual emissions, there is a risk that source owners or operators may shift production to these specific units, increasing their utilization and resulting in emissions increases from these units. Second, if some owners or operators were able to avoid the control requirements of the final rule on this basis, they could gain a competitive advantage vis-à-vis other facilities within their respective industries. Production could shift from units at another facility subject to the control requirements to the units that avoided control requirements (and thus avoid costs the regulated facility should bear), potentially resulting in emissions increases. The effect of such an approach in such circumstances would be mere emissions shifting rather than the elimination of significant

[249] For example, while the EPA has found it appropriate to limit the scope of emissions units that would be subject to emissions limits and controls in the iron and steel industry in light of comments regarding certain sources' inability to meet the EPA's proposed emission limits, this does not alter the EPA's determination that this industry is an impactful industry and that certain emissions controls should still be required.

contribution. Finally, as we have explained in prior transport actions, the cost-effectiveness figure is not the only factor that the agency considers at Step 3, *see* 86 FR 23073, and if used in isolation to make a policy decision without considering other information, could produce a result that is inconsistent with the objective of ensuring significant contribution is eliminated.[250]

In addition to our evaluation of cost-effectiveness on a cost per ton basis, the EPA's determination at Step 3 for non-EGUs is also informed by the overall level of emissions reductions that will be achieved across the region and the effect those reductions are projected to have on air quality at the downwind receptors (discussed more later in this section). We are also influenced by the fact that these emissions control strategies for non-EGUs are generally well demonstrated to be feasible on many existing units, as established through our review of consent decrees, permits, RACT determinations, and other data sources. These levels of emissions control have in many cases already been required by states with downwind nonattainment areas for the 2015 ozone NAAQS.

The EPA determined that, for 2026, the incremental average air quality improvement at receptors relative to the EGU case when SCR post-combustion controls were installed was 0.19 ppb when non-EGU controls were applied, based on the Step 3 analysis. The total average air quality improvement was 0.66 ppb when the non-EGU improvement was added to the EGU improvement, meaning that the non-EGU increment accounts for about 29 percent of this average air quality improvement. In general, the air quality results from non-EGU emissions reductions yield additional important downwind benefits to the air quality benefits of the EGU strategy. For example, the total ppb improvement summed over all of the receptors from EGUs was 7.04 ppb and the non-EGU increment adds another 2.82 ppb of improvement bringing the total to 9.87 (when accounting for rounding). Non-EGUs account for 29 percent of this total air quality improvement as well. Further, these figures should not be considered in isolation; EPA is not comparing EGU strategy effects and non-EGU effects to make a selection between two different approaches. Rather, both the selected EGU and non-EGU emissions reduction strategies at the cost-effectiveness values identified in section V.B and V.C of this document present a comprehensive solution to eliminating significant contribution for the covered states. The combined effect of the EGU and non-EGU strategies is further presented in the following section.

TABLE V.D.2–2—AIR QUALITY AT RECEPTORS IN 2026 FROM NON-EGU INDUSTRIES

Monitor ID No.	State	County	Average DV (ppb)		Max DV (ppb)	
			Baseline (engineering analysis)	EGU SCR/SNCR optimization + LNB upgrade + SCR/SNCR retrofit + non-EGU	Baseline (engineering analysis)	EGU SCR/SNCR optimization + LNB upgrade + SCR/SNCR retrofit + non-EGU
40278011	Arizona	Yuma	69.87	69.80	71.47	71.40
80590006	Colorado	Jefferson	71.70	71.34	72.30	71.93
80590011	Colorado	Jefferson	72.06	71.57	72.66	72.16
80690011	Colorado	Larimer	69.84	69.53	71.04	70.72
90013007	Connecticut	Fairfield	71.25	70.66	72.06	71.46
90019003	Connecticut	Fairfield	71.58	71.06	71.78	71.26
350130021	New Mexico	Dona Ana	70.06	69.86	71.36	71.16
350130022	New Mexico	Dona Ana	69.17	68.96	71.77	71.56
350151005	New Mexico	Eddy				
350250008	New Mexico	Lea				
480391004	Texas	Brazoria	69.89	68.50	72.02	70.58
481671034	Texas	Galveston	71.29	69.28	72.51	70.47
482010024	Texas	Harris	74.83	73.39	76.45	74.98
490110004	Utah	Davis	69.90	69.28	72.10	71.46
490353006	Utah	Salt Lake	70.50	69.91	72.10	71.50
490353013	Utah	Salt Lake	71.91	71.40	72.31	71.80
551170006	Wisconsin	Sheboygan	70.83	70.27	71.73	71.17
Average AQ Change Relative to Base (ppb)						0.66
Total PPB Change Across All Receptors Relative to Base (ppb)						9.87

Table Notes:

[a] The EPA notes that the design values reflected in Table V.D.–2 correspond to the engineering analysis EGU emissions inventory that was used in AQAT to determine state-level baseline emissions and reductions at Step 3. These tools are discussed in greater detail in the Ozone Transport Policy Analysis Final Rule TSD.

[b] New Mexico Eddy and Lea monitors have no values in Table V.D.2–2 as EPA does not have calibration factors for these monitors as no contributions were calculated for them from the proposal AQ modeling.

[c] The cumulative ppb change only shows the aggregate change across all problematic receptors (some of which are located within close proximity to one another) in this part of the Step 3 analysis. Section VIII of this document provides a more complete picture of the air quality impacts of the final rule.

[250] Nonetheless, recognizing the diverse non-EGU industries and emissions units covered in this action and the potential that certain individual facilities and emissions units may face extreme hardship in meeting the general requirements being finalized in this action, the EPA has provided mechanisms in the regulatory requirements for industrial sources that provide for some flexibility in the emissions limits based on a demonstration of technical impossibility or extreme economic hardship. *See* section VI.C of this document.

For more information about how this assessment was performed and the results of the analysis for each receptor, refer to the Ozone Transport Policy Analysis Final Rule TSD and to the Ozone AQAT included in the docket for this rule.

3. Combined EGU and Non-EGU Assessment

The EPA used the Ozone AQAT to evaluate the combined impact of these selected stringency levels for both EGUs and non-EGUs on all receptors remaining in the 2026 air quality modeling base case to inform the air quality effects of the rule and to conduct our over-control analysis. EPA's evaluation demonstrated air quality improvement at the remaining nonattainment or maintenance receptors outside of California (*see* section IV.D of this document for receptor details). The EPA estimated that the average air quality improvement at these receptors relative to the engineering analytics base case was 0.66 ppb for emissions reductions commensurate with optimization of existing SCRs/SNCRs, combustion control upgrades, application of new post-combustion control (SCR and SNCR) retrofits at eligible units, and all estimated emissions reductions from the non-EGU industries. Table V.D.3–1 summarizes the results of EPA's Step 3 evaluation of air quality improvements at these receptors using AQAT. In summary, the collective application of these mitigation measures and emissions reductions are projected to deliver meaningful downwind air quality improvements.

TABLE V.D.3–1—CHANGE IN AIR QUALITY AT RECEPTORS IN 2026 FROM FINAL RULE EGU AND NON-EGU EMISSIONS REDUCTIONS [a b c]

Sector/technology	Ozone season emissions reductions	Total PPB change across all downwind receptors [d]	Average PPB change across all downwind receptors
EGU (SCR/SNCR optimization + LNB upgrade)	16,282	0.71	0.05
EGU SCR/SNCR Retrofit	55,672	6.34	0.42
Non-EGU Industries	44,616	2.82	0.19
Total	....	9.87	0.66

Table Notes:

[a] As in prior rules, for the purpose of defining significant contribution at Step 3, the EPA evaluated air quality changes resulting from the application of the emissions reductions in only those states that are linked to each receptor as well as the state containing the receptor. By applying reductions to the state containing the receptor, the EPA ensures that it is accounting for the downwind state's fair share. In addition, this method holds each upwind state responsible for its fair share of the downwind problems to which it is linked. Reductions made by other states to address air quality problems at other receptors do not increase or decrease this share. The air quality impacts on design values that reflect the emissions reductions in all linked states and associated health and climate benefits are discussed in section VII of this document.

[b] The EPA notes that the design values reflected in Tables V.D.1–1 and –2 correspond to the engineering analysis EGU emissions inventory used in AQAT to determine state-level baseline emissions and reductions at Step 3. These tools are discussed in greater detail in the Ozone Transport Policy Analysis Final Rule TSD. Additionally, these emissions reduction values vary slightly from the technology reduction estimates described in section V.C of this document, as the values here reflect the sum of the final identified stringency for each state (*e.g.,* SCR retrofit potential is not assumed in Alabama, Minnesota, and Wisconsin).

[c] The total and average ppb results from non-EGUs emissions reductions shown here were generated using the Step 3 AQAT methodology consistent with that for EGUs (*i.e.,* including reductions from the state containing the receptor and excluding states that are not explicitly linked to particular receptors). The values shown in Table V.C.2–1 were prepared for the non-EGU screening assessment using a methodology where states within the program make emissions reductions for all receptors. States that contain receptors (*i.e.,* Connecticut and Colorado) that are not linked to other receptors are not assumed to make reductions under that methodology.

[d] The cumulative ppb change only shows the aggregate change across all problematic receptors (some of which are located within close proximity to one another) in this part of the Step 3 analysis. Section VIII of this document provides a picture of the projected air quality impacts of the final rule using modeling techniques that differ from the methodologies employed here.

4. Over-Control Analysis

The EPA applied its over-control test to this same set of aggregated EGU and non-EGU data described in the previous section. The EPA performed air quality analysis using the Ozone AQAT to determine whether the emissions reductions for both EGUs and non-EGUs potentially create an ''over-control'' scenario. As in prior transport rules following the holdings in *EME Homer City,* overcontrol would be established if the record indicated that, for any given state, there is an identified, less stringent emissions control approach for that state, by which (1) the expected ozone improvements would be sufficient to resolve all of the downwind receptor(s) to which that state is linked; or (2) the expected ozone improvements would reduce the upwind state's ozone contributions below the screening threshold (*i.e.,* 1 percent of the NAAQS or 0.70 ppb) to all receptors. In *EME Homer City,* the Supreme Court held that the EPA cannot ''require[] an upwind State to reduce emissions by more than the amount necessary to achieve attainment in every downwind State to which it is linked.'' 572 U.S. at 521. On remand from the Supreme Court, the D.C. Circuit held that this means that the EPA might overstep its authority ''when those downwind locations would achieve attainment even if less stringent emissions limits were imposed on the upwind States linked to those locations.'' *EME Homer City II,* 795 F.3d at 127. The D.C. Circuit qualified this statement by noting that this ''does not mean that every such upwind state would then be entitled to less stringent emissions limits. Some of those upwind States may still be subject to the more stringent emissions limits so as not to cause other downwind locations to which those States are linked to fall into nonattainment.'' *Id.* at 14–15. Further, as the Supreme Court explained, ''while EPA has a statutory duty to avoid over-control, the Agency also has a statutory obligation to avoid 'under-control,' *i.e.,* to maximize achievement of attainment downwind.'' 572 U.S. at 523. The Court noted that ''a degree of imprecision is inevitable in tackling the problem of interstate air pollution'' and that incidental over-control may be unavoidable. *Id.* ''Required to balance the possibilities of under-control and over-control, EPA must have leeway in fulfilling its statutory mandate.'' *Id.*[251]

[251] Although the Court described over-control as going beyond what is needed to address ''nonattainment'' problems, the EPA interprets this

Consistent with these instructions from the Supreme Court and the D.C. Circuit, using the Ozone AQAT, the EPA first evaluated whether reductions resulting from the selected control stringencies for EGUs in 2023 and 2026 combined with the emissions reductions selected for non-EGUs in 2026 can be anticipated to resolve any downwind nonattainment or maintenance problems (see the Ozone Transport Policy Analysis Final Rule TSD for details on the construction and application of AQAT).

Similar to our approach in the CSAPR Update and the Revised CSAPR Update, our primary overcontrol assessment examines the receptor changes from the emissions reductions of the upwind states found linked to a receptor. Consistent with prior Rules, EPA also assumed that downwind states that are not upwind states in this rule implement reductions commensurate with the rule's requirements (this treatment applies specifically to Colorado and Connecticut). This configuration effectively presents an equitable representation of the effects of the rule in that linked upwind states do not shift their responsibility to other upwind states linked to different receptors. It also effectively resolves any interdependence and ''which state goes first?'' questions. Furthermore, the downwind states in which a receptor is located are held to a ''fair share'' of emissions reductions—*i.e.,* the same level of emissions control stringency that the upwind states must implement.

The EPA also repeated this analysis using an alternative configuration, as described in the Ozone Transport Policy Analysis Final Rule TSD. In this configuration, we looked at the combined effect of the entire program across all linked upwind states on each receptor and did not assume that a downwind state that is not also an upwind state makes any additional emissions reductions beyond the baseline in the relevant year. This configuration effectively isolates how the rule as a whole, and just the rule, will affect air quality and linkages. While the first configuration described is, in the Agency's view, the more appropriate way to evaluate overcontrol, taken together the configurations provide a more robust basis on which to rest our conclusions regarding overcontrol. In any case, as further illustrated in the Ozone Transport Policy Analysis Final Rule TSD, our analysis under both configurations establishes that there is no overcontrol and so there is no need to reconcile any difference in results between them.

We also looked at the ordering of increments of emissions reduction and have found that it does not matter whether we assume EGU emissions controls would be applied first, followed by non-EGU controls, or vice-versa. For 2023, the question is moot as there are only EGU reductions to examine. For 2026, the analysis showed there would be no overcontrol either way. In 2026, the EPA's overcontrol analysis (as presented here) examined all EGU reductions first and layered in non-EGU reductions in the last step of the overcontrol check. However, the EPA also examined an alternative ordering scenario where the non-EGU reductions were assessed prior to the EGU reductions associated with installation of new SCR post-combustion controls (see the Ozone Transport Policy Analysis Final Rule TSD for details). This ordering did not impact the results of the overcontrol test. The specific results of these analyses are presented in the TSD.

The control stringency selected for 2023 (a representative cost threshold of $1,800 per ton for EGUs) includes emissions reductions commensurate with optimization of existing SCRs and SNCRs and installation of state-of-the-art combustion controls, is not estimated to change the status of any receptors.[252] Thus, the nonattainment or maintenance receptors that the states are linked to remain unresolved. Nor do any states' contribution levels drop below the 1 percent of NAAQS threshold. Thus, the EPA determined that none of the 23 linked states have all of their linkages resolved at the final EGU level of control stringency in 2023, and hence, the EPA finds no over-control in the final level of stringency.

Based on the air quality baseline modeling for 2026, all receptors to which Alabama, Minnesota, and Wisconsin are linked in 2023 are projected to be in attainment in 2026. Therefore, no additional stringency is finalized for EGUs or non-EGUs in those states beyond the 2023 level of stringency. For the remaining 20 states, the selected control stringency beginning in 2026 includes additional EGU controls and the non-EGU emissions reductions.

The EPA assesses air quality impacts and overcontrol in the year 2026 in this final rule, even though the rule accommodates the potential need for individual facilities (both EGU and non-EGU) to have some additional time to come into compliance. The EPA views this additional time to be a reflection of need (based on demonstrated impossibility) that is justified at Step 4 of the interstate transport framework rather than at Step 3. As explained in section VI.A of this document, with respect to EGUs, the EPA extends the full implementation of the SCR retrofit-based reductions across 2026 and 2027 to accommodate any *unit-level* scheduling challenges. However, we find that many sources can meet a three-year installation time and the trading program features and the allowance price will incentivize these reductions to occur as soon as possible. Similarly, with respect to non-EGU industrial sources, the final rule provides limited circumstances for individual facilities to seek and to be granted extensions of time to install required pollution controls and achieve the emissions rates established in this rule based on a showing of necessity. Those circumstances where an extension may be warranted for any specific facility are unknown at this time and will be evaluated through a source-specific application process, where the need for extension can be established with source-specific evidence. See section VI.C of this document. Further, 2026 is the critical analytic year associated with the last full ozone season before the 2027 Serious area attainment date and is the year by which significant contribution must be eliminated if at all possible. Therefore, for purposes of this analysis, the collective *state and regional* representation of these reductions are fully assumed in 2026. The potential ability of both EGU and non-EGU sources to have some amount of additional time beyond 2026 to comply with requirements that we have determined at Step 3 are necessary to eliminate significant contribution does not necessitate evaluating a later year than 2026 for overcontrol. The stringency of the control program does not alter in any year beyond 2026.[253] By

holding as not impacting its approach to defining and addressing both nonattainment and maintenance receptors. In particular, the EPA continues to interpret the Good Neighbor provision as requiring it to give independent effect to the ''interfere with maintenance'' prong. *Accord Wisconsin,* 938 F.3d at 325–27.

[252] For purposes of this rule, the violating monitor receptors inform our determinations at Step 1 and 2 by strengthening the analytical basis on which we conclude upwind states are linked in 2023. Because no linkages identified using our air quality modeling methodology resolve in 2023 under the selected control stringency, it is not necessary to evaluate overcontrol with respect to the additional set of violating-monitor receptors.

[253] Thus, we note, this circumstance is different than the record on which overcontrol was found in *EME Homer City.* There, CSAPR would have implemented an increase in the emissions control stringency of the rule (as reflected in a change in emissions control stringency expressed as dollars

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fully reflecting all Step 3 emissions reductions in its overcontrol test for 2026, EPA ensures that it is not understating the emissions impact and benefit when performing the test.

The EPA used the Ozone AQAT to evaluate the impact of this selected stringency level (as well as other potential stringency levels) on all receptors remaining in the 2026 air quality modeling base case. This assessment shows that the selected control stringency level is estimated to change the status of three receptors to attainment or maintenance in 2026. Brazoria County, Texas (Monitor ID 480391004); and Galveston County, Texas (Monitor ID 481671034), are estimated to come into attainment. We observe that one of the Fairfield, Connecticut, receptors (Monitor ID 090013007) is estimated to go from nonattainment to maintenance (when EGU emissions reductions with SCR are applied, prior to the application of the non-EGU emissions reductions). This receptor is expected to remain in maintenance even after the application of the non-EGU emissions reductions. Based on these data, EPA finds that all linked states except Arkansas, Mississippi, and Oklahoma are projected to continue to be linked to nonattainment or maintenance receptors after implementation of all identified Step 3 reductions, and hence, the EPA finds no over-control in its determination of that level of stringency for those states. Arkansas, Mississippi, and Oklahoma are linked to at least one of the two Texas receptors that are projected to come into attainment with the full implementation of the control strategy at Step 3. However, these two Texas receptors are expected to remain as maintenance-only receptors prior to the final increment of reductions assessed (the addition of the non-EGU reductions), so EPA concludes that imposition of the incremental non-EGU level is appropriate to avoid under-control as to these states and does not constitute overcontrol.[254]

Next, the EPA evaluated the potential for over-control with respect to the 1 percent of the NAAQS threshold applied in this final rulemaking at Step 3 of the good neighbor framework, assessed for the selected control stringencies for each state for each period that downwind nonattainment and maintenance problems persist (*i.e.,* 2023 and 2026). Specifically, the EPA evaluated whether the selected control stringencies would reduce upwind emissions to a level where the contribution from any of the 23 linked states in 2023 or 20 linked states in 2026 would be below the 1 percent threshold. The EPA finds that for the mitigation measures assumed in 2023 and in 2026, all states that contributed greater than or equal to the 1 percent threshold in the base case are projected to continue to contribute greater than or equal to 1 percent of the NAAQS to at least one remaining downwind nonattainment or maintenance receptor for as long as that receptor remained in nonattainment or maintenance. EPA notes that in 2026, for Oklahoma, when the incremental level of stringency associated with the non-EGU control strategy is applied, Oklahoma's contribution to Galveston County Texas is expected to drop below the 1 percent threshold (at the same time that the receptor has its maintenance problems resolved). EPA concludes that this does not constitute overcontrol because both the receptor and the contribution are estimated to remain above the maintenance level and linkage threshold at the prior level of stringency and, thus, since otherwise justified at Step 3, the full stringency for 2026 is appropriate to avoid under-control. For more information about this assessment, refer to the Ozone Transport Policy Analysis Final Rule TSD and the Ozone AQAT.

Therefore, EPA finds that all of the selected EGU and non-EGU NO_X reduction strategies selected in EPA's Step 3 analysis can be applied to all states linked in 2026 to eliminate significant contribution to nonattainment and interference with maintenance of the 2015 ozone NAAQS without introducing an overcontrol problem based on the present record. The Supreme Court has directed the EPA to avoid both over-control and under-control in addressing good neighbor obligations. In addition, the D.C. Circuit has reinforced that over-control must be established based on particularized, record evidence on an as-applied basis.

The determination that the stringency of this action does not constitute overcontrol for any linked state is further reinforced by EPA's observation in section III.A of this document regarding the nature of the ozone problem. Ozone levels are known to vary, at times dramatically, from year to year. Future ozone concentrations and the formation of ground level ozone may also be impacted by factors in future years that the EPA cannot fully account for at present. For example, changes to meteorological conditions could affect future ozone levels. Climate change could also contribute to higher than anticipated ozone levels in future years through wildfires and heat waves, which can contribute directly and indirectly to higher levels of ozone. Any modeling projection can be characterized as having some uncertainty, and that is not a sufficient reason to ignore modeling results. However, in the context of the overcontrol test, the question is whether it is clear according to particularized evidence that there is no need for the emissions reductions in question. *See EME Homer City,* 572 U.S. at 523 (''[A] degree of imprecision is inevitable in tackling the problem of interstate air pollution. Slight changes in wind patterns or energy consumption, for example, may vary downwind air quality in ways EPA might not have anticipated.''). Under this standard, the degree of attainment that is projected to occur under the rule in relation to the Texas receptors discussed above is not so large or certain to occur that it would be appropriate to attempt to devise a less stringent emissions control strategy for the relevant linked states as a result, particularly in light of the fact that at the penultimate stringency level the receptors are not resolved.

It is also possible that ozone-precursor emissions from certain sources may decline beyond what we currently project in this rule. For example, the IRA may result in reductions in fossil-fuel fired generation, which should in turn result in lower NO_X emissions during the ozone season.[255] We have

per ton from $100/ton to $500/ton). That change in stringency marked a determination that EPA had made at Step 3 regarding the degree of emissions reduction that sources needed to achieve beginning in 2014. But in that year, the court found EPA's record to reveal that certain states would not need to go up to that higher level of stringency because air quality problems and/or linkages were already projected to be resolved at the lower level of stringency. *See* 795 F.3d at 128–30. The analogous year to 2014 here is 2026. The stringency level of this control program does not change post-2026. Nor do we think individual sources should gain the benefit of delaying emissions reductions simply in the hopes that they could show those reductions would be overcontrol; each source must be held to the elimination of its portion of significant contribution. Necessity may demand some additional amount of time for compliance, but equity demands that individual sources not gain an untoward advantage from delay and reliance on other sources' timelier compliance.

[254] Even with full implementation of the rule, these two receptors are only projected to come into attainment by a relatively small degree, and no policy option is ascertained in the record by which attainment could be achieved to an even lesser degree. Nonetheless, the EPA further evaluated whether there were any overcontrol concerns through sensitivity analyses. Under all scenarios, the EPA finds there is no overcontrol. See the Ozone Transport Policy Analysis Final Rule TSD for more discussion and analysis.

[255] As discussed in section IV.C.2.b, there are also potential ways in which the IRA may not necessarily result in reductions in NO_X emissions from EGUs.

assessed this scenario to ensure our overcontrol conclusions are robust even if the IRA has those effects. As discussed in the Regulatory Impact Analysis, the EPA conducted additional modeling of the final policy scenario (inclusive of economically efficient methods of compliance available within the Step 4 implementation programs) using its IPM tool. The EPA observes that the differences in estimated costs and emissions reductions in the IRA sensitivity (presented in Appendix 4A of the RIA) suggests that there would also be differences in estimated health and climate benefits under that scenario, although the Agency did not have time under this rulemaking schedule to quantify those differences. The EPA also used AQAT to conduct an additional EGU modeling sensitivity reflecting the IRA. Both the IPM sensitivity and the corresponding AQAT assessment of the IRA scenarios demonstrated no overcontrol as every state linkage to a downwind problematic receptor persisted in the penultimate level of stringency when EPA performed its Step 3 evaluation—even when the impacts of the IRA are incorporated. This further affirmed EPA's conclusion of no overcontrol concerns at the stringency level of the final rule. This overcontrol sensitivity is further discussed in the Ozone Transport Policy Analysis Final Rule TSD, Appendix K.

In light of the mandate of the CAA to protect the public health and environment through the elimination of significant contribution under the Good Neighbor Provision for the 2015 ozone NAAQS, nothing in the present record establishes on an as-applied, particularized basis that this rule will result in an unnecessary degree of control of upwind-state emissions.

Comment: Many commenters alleged that the rule overcontrols emissions by more than necessary to eliminate significant contribution for the 2015 ozone NAAQS, on the basis that the emissions reductions are unnecessary or are unnecessarily stringent.

Response: As discussed earlier in this section, EPA has analyzed whether this rule ''overcontrols'' emissions and has found based on a robust, multi-faceted analysis, that it does not. In particular, EPA has not identified a lesser-stringency emissions control strategy for any state that would either fully resolve the air quality problems at a downwind receptor location or resolve that upwind state's linkage to a level below the 1 percent of NAAQS contribution threshold. No commenter has provided a particularized, as-applied analysis demonstrating that EPA's emissions control strategy will actually result in any overcontrol of emissions in the manner the EPA or courts have understood that term, and overcontrol allegations must be proven through particularized, as-applied challenges. *See EME Homer City,* 795 F.3d at 127; *see also Wisconsin,* 938 F.3d at 325 (''[T]he way to contest instances of over-control is not through generalized claims that EPA's methodology would lead to over-control, but rather through a 'particularized, as-applied challenge.' '' Accordingly, as we did when presented with similar arguments in *EME Homer III,* we reject Industry Petitioners' arguments because they do no more than speculate that aspects of 'EPA's methodology *could* lead to over-control of upwind States.' '') (cleaned up) (citing *EME Homer City,* 795 F.3d at 136–137).

Comment: For 2 of the 20 states linked in 2026, Arkansas and Mississippi, the last downwind receptor to which these two states are linked (*i.e.,* Brazoria County, Texas) was estimated to achieve attainment and maintenance after full application of EGU reductions and Tier 1 non-EGU reductions at proposal. Commenters noted that this suggested application of the estimated non-EGU, and/or some EGU, emissions reductions constituted over-control for these states.

Response: EPA notes that at proposal, this downwind receptor only resolved by a small margin after the application of all EGU and Tier 1 non-EGU emissions reductions. As explained earlier in this section, the final rule air quality modeling shows that the receptors to which these states are linked do not resolve upon full implementation of the identified EGU reductions by themselves, and only reach attainment by a small degree following the additional reductions from the non-EGU control strategy.[256] If the EPA were to select the control stringency of this penultimate step, both upwind-state contribution and downwind-state air quality receptors would persist while the cost-effective emissions reductions that were identified to eliminate significant contribution remain available but un-implemented. This would constitute under-control. Consequently, as described, the EPA views the control stringency required of these states in this final rule as not constituting over-control and appropriate to eliminate significant contribution to nonattainment and interference with maintenance of this NAAQS in line with our Step 3 determinations for all other states. See the Ozone Transport Policy Analysis Final Rule TSD section C.3 for discussion and analysis regarding overcontrol for states solely linked to one or both of these receptors.

Comment: Commenters raised a variety of arguments that the enhancements to the EGU trading program in this action will result in overcontrol of power plant emissions. They alleged that dynamic budgeting would cause the budget to continually decrease even after significant contribution is eliminated. They similarly argue that annual emissions bank recalibration and the emissions backstop emissions rate have not been shown to be justified to eliminate significant contribution.

Response: This final rule's determination regarding the appropriate level of control stringency for EGUs finds that the amounts of NO_X emissions reduction achieved through these strategies at EGUs are appropriate and cost-justified under the Step 3 multifactor analysis. These determinations are associated with particular emissions control technologies and strategies as detailed in sections V.B.1 and V.C.1 above. It is the implementation of those strategies at the covered EGU sources and the air quality effects of those strategies (coupled with non-EGUs) in the relevant analytic year of 2026 on which we base our determination of significant contribution at Step 3. This includes the evaluation of whether there is overcontrol, which is also conducted for the 2026 analytic year as explained above. As explained below, we disagree that the enhancements to the trading program at Step 4 implicate the need for further overcontrol analysis. These enhancements operate together to ensure the trading program continues to maintain the Step 3 emissions control stringency over time. These enhancements reflect lessons learned through EPA's experience with prior trading programs implemented under the good neighbor provision. None of commenters' arguments that these enhancements result in overcontrol are persuasive.

Commenters contend that these enhancements to the trading program go

[256] Because in the final record we do not identify cost, air quality, and emission reduction factors that sufficiently differentiate either source-type or emissions control strategy among the Tier 1 and Tier 2 industries identified at proposal, we combined the non-EGU industries and emissions reductions into one group, and we are finalizing requirements for all non-EGU industries and most emissions unit types identified at proposal. In light of the small degree to which the relevant receptors reach attainment and the multi-faceted assessment of overcontrol we have undertaken, the overcontrol assessment with respect to non-EGUs in the final rule is sufficient to establish that there is no overcontrol.

beyond a mass-based budget approach as applied in CSAPR. Because these improvements in the program result in a continuing incentive for each covered EGU source to maintain the pollution control performance the EPA found appropriate to eliminate significant contribution at Step 3, commenters believe these enhancements must necessarily result in prohibited overcontrol. These arguments appear to be premised on the assumption that overall emissions may later decline to such a point that there is no longer a linkage between a particular state and any downwind receptors for reasons other than the requirements of this rule.

As an initial matter, no commenter has provided an empirical analysis demonstrating that the control stringency identified at Step 3 to eliminate significant contribution would actually result in any overcontrol. The case law is clear that over-control allegations must be proven through particularized, as-applied challenges. See prior response to comments. More importantly here, the Group 3 trading program enhancements do not impose increased stringency in years after 2030 and do not force emissions to continually be reduced to ever lower levels. They are only designed to incentivize the implementation of the Step 3 emissions control stringency that eliminates significant contribution. The circumstances that could potentially cause a receptor or linkage to resolve at some point in the future after 2026 are not circumstances that are within the power of this rule to control. Nor would those circumstances present a justification as to why upwind sources should no longer be obligated to eliminate their own significant contribution. *Wisconsin,* 938 F.3d at 324–25 (rejecting overcontrol arguments premised on attributing air quality problems to other emissions).

Further, the EPA is not constrained by the statute to only implement good neighbor obligations through fixed, unchanging, mass-based emissions budgets. *See* section III.B.1 of this document. The EPA has defined the ''amount'' of emissions that must be prohibited to eliminate significant contribution in this action based on a series of determinations of which emissions control strategies, for certain identified EGU and non-EGU sources, are appropriate applying the Step 3 multifactor analysis. Notably, the non-EGU industrial source emissions reductions in this action are *not* being achieved at Step 4 through mass-based emissions trading, nor are they required to be by any provision of the CAA. See section III.B.1.

As explained in sections III.B.1.d and VI.B.1 of this document, the EPA finds good reason based on its experience with trading programs that using fixed, mass-based, ozone-season wide budgets does not necessarily ensure the elimination of significant contribution over the entire region of linked states or throughout each ozone season. Even in the original CSAPR rulemaking, which promulgated only fixed, mass-based budgets, such outcomes were never the EPA's intention to allow. *See, e.g.,* 76 FR 48256–57 (''[I]t would be inappropriate for a state linked to downwind nonattainment or maintenance areas to stop operating existing pollution control equipment (which would increase their emissions and contribution).''). Despite the EPA's expectations in CSAPR, the experience of the Agency since that time establishes a real risk of ''under-control'' if the existing trading framework is not enhanced. *See EME Homer City,* 572 U.S. at 523 (''[T]he Agency also has a statutory obligation to avoid 'under-control,' *i.e.,* to maximize achievement of attainment downwind.'').

Further, the EPA has already once adjusted its historical approach to better account for known, upcoming changes in the EGU fleet to ensure mass-based emissions budgets adequately incentivize the control strategy determined at Step 3. This adjustment was introduced in the Revised CSAPR Update. *See* 82 FR 23121–22. The EPA now believes it is appropriate to ensure in a more comprehensive manner, and in perpetuity, that a mass-based emissions-trading framework incentivizes continuing implementation of the Step 3 control strategies to ensure significant contribution is eliminated in all upwind states and remains so. This is fully analogous in material respect to an approach to implementation at Step 4 that relies on application of unit-specific emissions limitations, which under the Act would typically apply in perpetuity and may only be modified through a future SIP- or FIP-revision rulemaking process. *See* CAA section 110(i) prohibiting modifications to implementation plan requirements except by enumerated processes. The availability of unit-specific emissions rates as a means to eliminate significant contribution is discussed in further detail in section III.B.1 of this document. The EPA also explained this in the proposal. *See* 87 FR 20095–96.

Further, these enhancements are directly related to assisting downwind areas specifically with the goal of attaining and maintaining the 2015 8-hour ozone NAAQS. In this respect, they are not ''unnecessary'' or ''unrelated'' to carrying out the mandates of CAA section 110(a)(2)(D)(i)(I). Taking measures to ensure that each upwind source covered by an emissions trading program is adequately incentivized to eliminate excessive emissions (as found at Step 3) throughout the entirety of each ozone season is entirely appropriate in light of the nature of the ozone problem. Ozone exceedances recur on varying days throughout the summertime ozone season, and it is not possible to predict in advance which specific days will have high ozone. Further, impacts to public health and the environment from ozone can occur through short-term exposure (*e.g.,* over a course of hours, *i.e.,* on a daily basis). The 2015 ozone NAAQS is expressed as an 8-hour average, and only a small number of days in excess of the ozone NAAQS can cause a downwind area to be in nonattainment. Thus, even a small number of exceedances can result in continuing and/or increased regulatory burdens on the downwind jurisdiction. Taking these considerations into account, it is evident that a fixed, mass-based emissions program that does not adequately incentivize emissions reductions commensurate with our Step 3 determinations on each day of every ozone season going forward does not provide a sufficient guarantee that the emissions that significantly contribute on those particular days and at particular receptor locations when ozone levels are at risk of exceeding the NAAQS have been eliminated. *See* section V.B.1.a and VI.B of this document for more discussion of data observations regarding SCR optimization.

These enhancements are also consistent with the general policies and principles EPA has long applied in implementing the NAAQS through the SIP/FIP framework of section 110. Emissions control measures relied on to meet CAA requirements must be permanent and enforceable and included in the implementation plan itself. *See, e.g., Montana Sulfur & Chem. Co.* v. *EPA,* 666 F.3d 1174, 1196 (9th Cir. 2012); 40 CFR 51.112(a). In the General Preamble laying out EPA's plans for implementing the 1990 CAA Amendments, the EPA identified a core ''principle'' that control strategies should be ''accountable.'' ''This means, for example, that source-specific limits should be permanent and must reflect the assumptions used in the SIP demonstrations.'' 57 FR 13498, 13568 (April 16, 1992). EPA went on, ''The principles of quantification, enforceability, replicability, and accountability apply to all SIPs and control strategies, including those involving emissions trading, marketable permits and allowances.'' *Id.* EPA also explained that its ''emissions trading policy provides that only trades producing reductions that are surplus, enforceable, permanent, and quantifiable can get credit and be banked or used in an emissions trade.'' *Id.* These principles follow from the language of the Act, including CAA section 110(a)(2), 107(d)(3)(E)(iii), 110(i), and 110(l). These provisions and principles further underscore the importance of ensuring that the emissions reductions the EPA has found necessary to eliminate significant contribution are in fact implemented on a consistent and permanent basis even within the context of an emissions trading program.

The EPA disagrees that the budget adjustments that would occur over time under this final rule (for example, the annual dynamic-budget adjustment) must be reassessed each time they occur through notice and comment rulemaking under CAA section 307(d). This would serve no purpose. The formulas that the EPA will apply to adjust the budgets and allowance bank are set in this final rule and are intended to maintain, not increase (or decrease), program stringency. While the EPA intends to provide an opportunity for stakeholders to review and propose corrections to its data as it implements the established budget formulas, no larger reassessment of the emissions control program is needed on an ongoing basis, because, again, that program is simply calibrated to ensure that emissions reductions commensurate with the determination of ''significance'' in Step 3 continue to be obtained over the long term. As described earlier, these trading program provisions are analogous to, or mimic, the effect of unit-specific emissions limitations that apply in perpetuity.[257]

Commenters also confuse the ''amount'' of emissions that must be eliminated under CAA section 110(a)(2)(D)(i)(I) as being synonymous with a fixed, mass-based budget that reflects the residual emissions allowed following the elimination of significant contribution. However, EPA views the ''amount'' to be eliminated as those emissions that are in excess of the cost-effective emissions control strategies identified in Step 3. This is further explained in section III.B.1 of this document.

Thus, this rule is in compliance with the overcontrol principles that the D.C. Circuit applied on remand in *EME Homer City* to find certain instances of overcontrol in CSAPR's emissions control strategies. The D.C. Circuit found that EPA had imposed more stringent emissions-control strategies for certain states than were necessary to resolve all of those states' linkages. 795 F.3d at 128–30. Specifically, for sulfur dioxide, the court found certain receptors would reach attainment if all linked upwind states had implemented ''cost controls'' at $100/ton or $400/ton, rather than EPA's selected stringency level of $500/ton. Similarly, for ozone season NO_X, the court found that receptors were projected to attain the NAAQS at stringencies below $500/ton. The court's focus was on the *stringency* of the emissions control obligations as determined through the application of cost thresholds at Step 3 of the analysis. The court did not hold that EPA may only use fixed, mass-based budgets to implement those reductions. The court did not hold that EPA must permit individual polluting sources to be allowed to increase their emissions at some point in the future. The court did not hold that EPA's good neighbor FIPs must, effectively, contain termination clauses, such that they cease to ensure the implementation of the control stringency determined as necessary at Step 3, the moment a downwind receptor reaches attainment. Indeed, such a rule would contravene the statute's clear, forward-looking directive that EPA must also eliminate upwind emissions that interfere with *maintenance* of the NAAQS; *see North Carolina,* 531 F.3d at 908–911; *Wisconsin,* 938 F.3d at 325–26.

The *EME Homer City* court on remand in fact rejected various arguments that other aspects of EPA's emissions control strategy in CSAPR resulted in overcontrol, holding that EPA had properly given effect to the interfere with maintenance prong, and noting that petitioners failed to make out proven, as-applied demonstrations of overcontrol:

> At bottom, each of those claims is an argument that EPA's methodology could lead to over-control of upwind States that are found to interfere with maintenance at a downwind location. That could prove to be correct in certain locations. But the Supreme Court made clear in *EME Homer* that the way to contest instances of over-control is not through generalized claims that EPA's methodology would lead to over-control, but rather through a ''particularized, as-applied challenge.'' *EME Homer,* 134 S. Ct. at 1609, slip op. at 31. And petitioners do not point to any actual such instances of over-control at downwind locations.

795 F.3d at 137. The court went on to observe, ''EPA may only limit emissions 'by just enough to permit an already-attaining State to maintain satisfactory air quality.' If States have been forced to reduce emissions beyond that point, affected parties will have meritorious as-applied challenges.'' *Id.* (quoting 572 U.S. at 521–22). But this too was not a holding that EPA may not ensure effective and permanent implementation of an emissions control stringency that EPA has found warranted under CAA section 110(a)(2)(D)(i)(I). Such an approach is available through the more conventional CAA practice of setting unit-specific emissions limitations that would apply on a permanent and enforceable basis. *See* CAA sections 110(a)(2) and 302(y) (providing for SIPs and FIPs to include ''enforceable emissions limitations'' in addition to economic incentive measures like trading programs).[258] This is in fact how EPA intends to ensure significant contribution is eliminated from non-EGU industrial sources for which a mass-based trading regime is, at least at the present time, unworkable (see section VI.C of this document). And EPA has provided for the elimination of significant contribution through source-specific emissions limitations in prior transport actions as well, so this position is not novel. See section III.B of this document.

Nonetheless, EPA recognizes that under the Act, both FIPs and SIPs may be revised, and states may replace FIPs with SIPs if EPA approves them. Any such revision must be evaluated to ensure no applicable CAA requirements are interfered with. *See, e.g., Indiana* v. *EPA,* 796 F.3d 803 (7th Cir. 2015). For example, states may be able to demonstrate in the future that through some other permanent and enforceable methods of emissions reduction that they have adopted into their SIP, they will be able to achieve a similar emissions control stringency with different emissions reduction requirements imposed on different sources as compared to the FIPs finalized in this action. See section VI.D of this document.

Therefore, commenters' contentions that EPA's trading program enhancements result in prohibited

[257] We note further that because all of the trading program provisions, including the dynamic budget-setting provisions and process, are established by this final FIP rulemaking, the ministerial future-year budget adjustment process complies with the CAA section 110(i) prohibition on modification of implementation plan requirements except by enumerated process.

[258] ''Emissions limitation'' is in turn defined at CAA section 302(k) as a ''requirement . . . which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis. . . .''

overcontrol are not proven through as-applied, particularized challenges, and they are premised on an incorrect understanding of the CAA and the relevant case law. The Agency rejects the contention that it must somehow provide in the present FIP action for a relaxation in the stringency of the Step 4 implementation program and thus allow for the recurrence of pollution that we have found here, in this action, significantly contributes to downwind ozone nonattainment and maintenance problems.

VI. Implementation of Emissions Reductions

A. NO_X Reduction Implementation Schedule

This action will ensure that emissions reductions necessary to eliminate significant contribution will be achieved ''as expeditiously as practicable'' and no later than the downwind attainment dates except where compliance by those dates is not possible. *See* CAA section 181(a); *Wisconsin,* 938 F.3d at 318–20. The timing of this action will provide for all possible emissions reductions to go into effect beginning in the 2023 ozone season for the covered states, which is aligned with the next upcoming attainment date of August 3, 2024, for areas classified as Moderate nonattainment under the 2015 ozone standard. Additional emissions reductions that the EPA finds not possible to implement by that attainment date will take effect as expeditiously as practicable. Emissions reductions commensurate with SCR mitigation measures for EGUs will start in 2026 and be fully implemented by 2027. Emissions reductions through the mitigation measures for industrial sources will generally go into effect in 2026; however, as explained in section VI.C of this document, we have provided for case-by-case extensions of up to one year based on a demonstration of necessity (with the potential for up to an additional two years based on a further demonstration). The full suite of emissions reductions is generally anticipated to take effect by the 2027 ozone season, which is aligned with the August 3, 2027, attainment date for areas classified as Serious nonattainment under the 2015 ozone NAAQS. This rule constitutes a full remedy for interstate transport for the 2015 ozone NAAQS for the states covered; the EPA does not anticipate further rulemaking to address good neighbor obligations under this NAAQS will be required for these states with the finalization of this rule.

EPA's determinations regarding the timing of this rule are informed by and in compliance with several recent court decisions. The D.C. Circuit has reiterated several times that, under the terms of the Good Neighbor Provision, upwind states must eliminate their significant contributions to downwind areas ''consistent with the provisions of [title I of the Act],'' including those provisions setting attainment deadlines for downwind areas.[259] In *North Carolina,* the D.C. Circuit found the 2015 compliance deadline that the EPA had established in CAIR unlawful in light of the downwind nonattainment areas' 2010 deadline for attaining the 1997 NAAQS for ozone and $PM_{2.5}$.[260] Similarly, in *Wisconsin,* the Court found the CSAPR Update unlawful to the extent it allowed upwind states to continue their significant contributions to downwind air quality problems beyond the downwind states' statutory deadlines for attaining the 2008 ozone NAAQS.[261] In *Maryland,* the Court found the EPA's selection of a 2023 analysis year in evaluating state petitions submitted under CAA section 126 unlawful in light of the downwind Marginal nonattainment areas' 2021 deadline for attaining the 2015 ozone NAAQS.[262] The Court noted in *Wisconsin* that the statutory command—that compliance with the Good Neighbor Provision must be achieved in a manner ''consistent with'' title I of the CAA—may be read to allow for some deviation from the mandate to eliminate prohibited transport by downwind attainment deadlines, ''under particular circumstances and upon a sufficient showing of necessity,'' but concluded that ''[a]ny such deviation would need to be rooted in Title I's framework'' and would need to ''provide a sufficient level of protection to downwind States.''[263]

1. 2023–2025: EGU NO_X Reductions Beginning in 2023

The near-term EGU control stringencies and corresponding reductions in this rulemaking cover the 2023, 2024, and 2025 ozone seasons. This is the period in which some reductions will be available, but the portion of full remedy reductions related to post combustion control installation identified in sections V.B through V.D of this document are not yet available. The EGU NO_X mitigation strategies available during these initial 3 years are the optimization of existing post-combustion controls (SCRs and SNCRs) and combustion control upgrades. As described in sections V.B through V.D of this document and in accompanying TSDs, these mitigation measures can be implemented in under two months in the case of existing control optimization and in 6 months in the case of combustion control upgrades. These timing assumptions account for planning, procurement, and any physical or structural modification necessary. The EPA provides significant historical data, including the implementation of the most recent Revised CSAPR Update, as well as engineering studies and input factor analysis documenting the feasibility of these timing assumptions. However, these timing assumptions are representative of fleet averages, and the EPA has noted that some units will likely overperform their installation timing assumptions, while others may have unit configuration or operational considerations that result in their underperforming these timing assumptions. As in prior interstate transport rules, the EPA is implementing these EGU reductions through a trading program approach. The trading program's option to buy additional allowances provides flexibility in the program for outlier sources that may need more time than what is representative of the fleet average to implement these mitigation strategies while providing an economic incentive to outperform rate and timing assumptions for those sources that can do so. In effect, this trading program implementation operationalizes the mitigation measures as state-wide assumptions for the EGU fleet rather than unit-specific assumptions.

However, starting in 2024, as described in section VI.B.7 of this document, unit-specific backstop daily emissions rates are applied to coal units with existing SCR at a level consistent with operating that control. The EPA believes that implementing these emissions reductions through state emissions budgets starting in 2023 while imposing the unit-specific backstop emissions rates in 2024 achieves the necessary environmental

[259] *North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir. 2008), *Wisconsin* v. *EPA,* 938 F.3d 303 (D.C. Cir. 2019), and *Maryland* v. *EPA,* 958 F.3d 1185 (D.C. Cir. 2020).

[260] *North Carolina,* 531 F.3d at 911–913.

[261] *Wisconsin,* 938 F. 3d at 303, 3018–20.

[262] *Maryland,* 958 F.3d at 1203–1204. Similarly, in *New York* v. *EPA,* 964 F.3d 1214 (D.C. Cir. 2020), the Court found the EPA's selection of a 2023 analysis year in evaluating New York's section 126 petition unlawful in light of the New York Metropolitan Area's 2021 Serious area deadline for attaining the 2008 ozone NAAQS. 964 F.3d at 1226 (citing *Wisconsin* and *Maryland*).

[263] *Wisconsin,* 938 F. 3d at 320 (citing CAA section 181(a) (allowing one-year extension of attainment deadlines in particular circumstances) and *North Carolina,* 531 F.3d at 912).

performance as soon as possible while accommodating any heterogeneity in unit-level implementation schedules regarding daily operation of optimized SCRs.

Additionally, as in prior rules, the EPA assumes combustion control upgrade implementation may take up to 6 months. In the Revised CSAPR Update, covering 12 of the 22 states for which emissions reduction requirements for EGUs are established under this action, the EPA finalized the rule in March of 2021 and thus did not require these combustion control-based emissions reductions in ozone-season state emissions budgets until 2022 (year two of that program).[264] The EPA is applying the same timing assumption regarding combustion control upgrades for this rulemaking. Given the same relationship here between the date of final action and the year one ozone season, the EPA is not assuming the implementation of any additional combustion control upgrades in state emissions budgets until year two (*i.e.,* the 2024 ozone season). Any identified combustion control upgrade emissions reductions are reflected beginning in the 2024 ozone-season budgets for all covered states. For the 12 states covered under the Revised CSAPR Update, any identified emissions reduction potential from combustion control upgrade is included and reflected in those state budgets beginning in 2024—which means EGUs in those states have even more time than the 14 months between finalization of this rule and the 2024 ozone season if they started any planning or installation earlier in response to the Revised CSAPR Update.

2. 2026 and Later Years: EGU and Stationary Industrial Source NO_X Reductions Beginning in 2026

The EPA finds that it is not possible to implement all necessary emissions controls across all of the affected EGU and non-EGU sources by the August 3, 2024, Moderate area attainment date. In accordance with the good neighbor provision and the downwind attainment schedule under CAA section 181 for the 2015 ozone NAAQS, the EPA is aligning its analysis and implementation of the emissions reductions addressing significant contribution from EGU and non-EGU sources that require relatively longer lead time at a sectoral scale with the 2026 ozone season. The 2026 ozone season is the last full ozone season that precedes the August 3, 2027, Serious area attainment date for the 2015 ozone NAAQS.[265] The EPA proposed to require compliance with all of the remaining EGU and non-EGU control requirements beginning in the 2026 ozone season. The EPA continues to find 2026 to be the relevant analytic year for purposes of its Step 3 analysis, including its analysis of overcontrol, as discussed in section V.D.4 of this document. However, many commenters argued that full implementation of the EGU and industrial source control strategies is not feasible for every source by the 2026 ozone season. The EPA addresses these technical comments specifically in sections V.B and VI.C of this document. The EPA also commissioned a study to develop a better understanding of the time needed for installation of emissions controls for the industrial sector units covered in this rule, which is included in the docket and discussed in section VI.A.2.b of this document. While the EPA does not agree with all of the commenters' assertions regarding the time they claim is needed for control installation, in other respects the concerns raised were sufficient to justify some adjustments to the compliance schedule for the final rule. We have provided for the emissions reductions commensurate with assumed EGU post-combustion emissions control retrofits to be phased in over the 2026 and 2027 ozone season emissions budgets, and we have provided a process in the final regulations for individual non-EGU industrial sources to seek limited compliance extensions extending no later than 2029 based on a case-by-case demonstration of necessity. This compliance schedule delivers substantial emissions reductions in the 2026 and 2027 ozone seasons and before the 2027 Serious area attainment date, and it only allows compliance extensions beyond that attainment date based on a rigorous, source-specific demonstration of need for the additional time.[266]

The timing of this final rule provides three to four years for EGU and non-EGU sources to install whatever controls they deem suitable to comply with required emissions reductions by the start of the 2026 and 2027 ozone seasons. In addition, the publication of the proposal provided roughly an additional year of notice to these source owners and operators that they should begin engineering and financial planning (steps that can be taken prior to any capital investment) to be prepared to meet this implementation timetable.

The EPA views this timeframe for retrofitting post-combustion NO_X emissions controls and other non-EGU controls to be reasonable and achievable. A 3-year period for installation of control technologies is consistent with the statutory timeframe for implementation of the controls required to address interstate pollution under section 110(a)(2)(D) and 126 of the Act, the statutory timeframes for implementation of RACT in ozone nonattainment areas classified as Moderate or above, and other statutory provisions that establish control requirements for existing stationary sources of pollution.

For example, section 126 of the CAA authorizes a downwind state or tribe to petition the EPA for a finding that emissions from ''any major source or group of stationary sources'' in an upwind state contribute significantly to nonattainment in, or interfere with maintenance by, the downwind state. If the EPA makes a finding that a major source or a group of stationary sources emits or would emit pollutants in violation of the relevant prohibition in CAA section 110(a)(2)(D), the source(s) must shut down within three months from the finding unless the EPA directly regulates the source(s) by establishing emissions limitations and a compliance schedule extending no later than three years from the date of the finding, to eliminate the prohibited interstate transport of pollutants as expeditiously as practicable.[267] Thus, in the provision that allows for direct Federal regulation of sources violating the good neighbor provision, Congress established three years as the maximum amount of time available from a final rule to when emissions reductions need to be achieved at the relevant source or group of sources. Because this action is not taken under CAA section 126(c), the mandatory timeframe for implementation of emissions controls

[264] 86 FR 23093.

[265] For each nonattainment area classified under CAA section 181(a) for the 2015 ozone NAAQS, the attainment date is ''as expeditiously as practicable'' but not later than the date provided in table 1 to 40 CFR 51.1303(a). Thus, for areas initially designated nonattainment effective August 3, 2018 (83 FR 25776), the latest permissible attainment dates are: August 3, 2021 (for Marginal areas), August 3, 2024 (for Moderate areas), August 3, 2027 (for Serious areas), and August 3, 2033 (for Severe areas).

[266] While we generally use the term ''necessity'' to describe the showing that non-EGU facilities must meet in seeking compliance extensions, the elements for this showing are designed to allow the EPA to make a judgment that comports with the standard of ''impossibility'' established in case law such as *Wisconsin*. In other words, the ''necessity'' for additional time is effectively a showing by the source that it would be ''impossible'' for it to meet the compliance deadline.

[267] CAA 110(a)(2)(D)(i) and 126(c).

under that provision is not directly applicable, but it is informative.

In response to arguments from sources that more time than has been provided in the final rule is necessary, this provision strongly indicates that allowing time beyond a three-year period must be based on a substantial showing of impossibility. Our analysis based on comments and considering additional information is that the additional time we have provided in the final rule is both justified and sufficient in light of the statutory objective of expeditious compliance.

Additionally, for ozone nonattainment areas classified as Moderate or higher, the CAA requires states to implement RACT requirements less than three years after the statutory deadline for submitting these measures to the EPA.[268] Specifically, for these areas, CAA sections 182(b)(2) and 182(f) require that states implement RACT for existing VOC and NO_X sources as expeditiously as practicable but no later than May 31, 1995, approximately 30 months after the November 15, 1992, deadline for submitting RACT SIP revisions. For purposes of the 2015 ozone NAAQS, the EPA has interpreted these provisions to require implementation of RACT SIP revisions as expeditiously as practicable but no later than January 1 of the fifth year after the effective date of designation, which is less than three years after the deadline for submitting RACT SIP revisions.[269] For areas initially designated nonattainment with a Moderate or higher classification effective August 3, 2018 (83 FR 25776), that implementation deadline falls on January 1, 2023, approximately 29 months after the August 3, 2020 submission deadline.[270] Moderate ozone nonattainment areas must also implement all reasonably available control measures (including RACT) needed for expeditious attainment within three years after the statutory deadline for states to submit these measures to the EPA as part of a Moderate area attainment demonstration.[271] Nonattainment areas for the 2015 ozone NAAQS that were reclassified to Moderate nonattainment in October 2022 face this same regulatory schedule, meaning that their sources are required to implement RACT controls in 2023. With the exception of the Uinta Basin, which is not an identified receptor in this action, no Marginal nonattainment area met the conditions of CAA section 181(a)(5) to obtain a one-year extension of the Moderate area attainment date. 87 FR 60899 (Oct. 7, 2022). Thus, all Marginal areas (other than Uinta) that failed to attain have been reclassified to Moderate. *Id.* In the October 2022 final rulemaking EPA made determinations that certain Marginal areas failed to attain by the attainment date, reclassified those areas to Moderate, and established SIP submission deadlines and RACM and RACT implementation deadlines. EPA set the attainment SIP submission deadlines for the bumped up Moderate areas to be January 1, 2023. *See* 87 FR 60897, 60900. The implementation deadline for RACM and RACT is also January 1, 2023. *Id.*

The EPA notes that the types and sizes of the EGU and non-EGU sources that the EPA includes in this rule, as well as the types of emissions control technologies on which the EPA bases the emissions limitations that would take effect for the 2026 and 2027 ozone seasons, generally are consistent with the scope and stringency of RACT requirements for existing major sources of NO_X in downwind Moderate nonattainment areas and some upwind areas, which many states have already implemented in their SIPs.[272] Thus, the timing Congress allotted for sources in downwind states to come into compliance with RACT requirements bears directly on the amount of time that should be allotted here and indicates, as does CAA section 126, that three years is an outer limit on the time that should be given sources to come into compliance where possible. In light of the January 1, 2023, deadline for implementation of RACT in Moderate nonattainment areas, the EPA finds that a May 1, 2026 deadline for full implementation of the emissions control requirements in this final rule would generally provide adequate time for any individual source to install the necessary controls, barring the circumstances of necessity discussed further in this section.

Finally, with respect to emissions standards for hazardous air pollutants, section 112(i)(3) of the CAA requires the EPA to establish compliance dates for each category or subcategory of existing sources subject to an emissions standard that ''provide for compliance as expeditiously as practicable, but in no event later than 3 years after the effective date of such standard,'' with limited exceptions. CAA section 112(i)(3)(B) authorizes the EPA to grant an extension of up to 1 additional year for an existing source to comply with emissions standards ''if such additional period is necessary for the installation of controls,'' and sections 112(i)(4) through (7) provide for limited compliance extensions where other conditions are met.[273] Here again, where Congress was concerned with addressing emissions of pollutants that impact public health, a 3-year time period was allotted as the time needed for existing sources to come into compliance where possible. As discussed further in section VI.A.2.b of this document, the process for obtaining a compliance extension for industrial sources in this rule is generally modeled on 40 CFR 63.6(i)(3), which implements

[268] *See, e.g.,* 40 CFR 51.1112(a)(3) and 51.1312(a)(3)(i) (requiring implementation of RACT required pursuant to initial nonattainment area designations no later than January 1 of the fifth year after the effective date of designation, which is less than 3 years after the SIP submission deadline under 40 CFR 51.1112(a)(2)) and 51.1312(a)(2)(i), respectively).

[269] 40 CFR 51.1312(a)(2)(i) (requiring submission of RACT SIP revisions no later than 24 months after the effective date of designation) and 40 CFR 51.1312(a)(3)(i) (requiring implementation of RACT SIP revisions as expeditiously as practicable, but no later than January 1 of the fifth year after the effective date of designation). For reclassified areas, states must implement RACT SIP revisions as expeditiously as practicable, but no later than the start of the attainment year ozone season associated with the area's new attainment deadline, or January 1 of the third year after the associated SIP revision submittal deadline, whichever is earlier; or the deadline established by the Administrator in the final action issuing the area reclassification. 40 CFR 51.1312(a)(3)(ii); *see* also 83 FR 62989, 63012–63014.

[270] 40 CFR 51.1312(a)(2)(i) (requiring submission of RACT SIP revisions no later than 24 months after the effective date of designation).

[271] *See, e.g.,* 40 CFR 51.1108(d) (requiring implementation of all control measures (including RACT) needed for expeditious attainment no later than the beginning of the attainment year ozone season, which, for a Moderate nonattainment area, occurs less than 3 years after the deadline for submission of reasonably available control measures under 40 CFR 51.1112(c) and 51.1108(a)) and 40 CFR 51.1308(d) (requiring implementation of all control measures (including RACT) needed for expeditious attainment no later than the beginning of the attainment year ozone season, which, for a Moderate nonattainment area, occurs less than three years after the deadline for submission of reasonably available control measures under 40 CFR 51.1312(c) and 51.1308(a)). Because the attainment demonstration for a Moderate nonattainment area (including RACT needed for expeditious attainment) is due three years after the effective date of the area's designation (40 CFR 51.1308(a) and 51.1312(c)), and all Moderate nonattainment areas must attain the NAAQS as expeditiously as practicable but no later than 6 years after the effective date of the area's designation (40 CFR 51.1303(a)), the beginning of the ''attainment year ozone season'' (as defined in 40 CFR 51.1300(g)) for such an area is less than three years after the due date for the attainment demonstration.

[272] *See* the Final Non-EGU Sectors TSD for a discussion of SIP-approved RACT rules in effect in downwind states.

[273] *See, e.g.,* CAA section 112(i)(4), which provides for limited compliance extensions granted by the President based on national security interests.

the extension provision for existing sources under CAA section 112(i)(3)(B).

All of these statutory timeframes for implementation of new control requirements on existing stationary sources indicate that Congress considered 3 years to be not only a sufficient amount of time but an upper bound of time allowable (barring instances of impossibility) for existing stationary sources to install or begin the installation of pollution controls as necessary for expeditious attainment, to eliminate prohibited interstate transport of pollutants, and to protect public health.

Further, the EPA notes that, given the number of years that have passed since EPA's promulgation of the 2015 ozone NAAQS and related nonattainment area designations in 2018, and in light of the *Maryland* court's holding that good neighbor obligations for the 2015 ozone NAAQS should have been implemented by the Marginal area attainment date in 2021,[274] the implementation of good neighbor obligations for these NAAQS is already delayed, and the sources subject to NO_X emissions control in this rule have continued to operate for several years without the controls necessary to eliminate their significant contribution to ongoing and persistent ozone nonattainment and maintenance problems in other states. Under these circumstances, we find it reasonable to require compliance with the control requirements for all non-EGUs and the EGU reductions related to post-combustion control retrofit identified in section V.B.1.b of this document beginning in the 2026 ozone season (with full implementation by the 2027 ozone season for EGUs, and the availability of source-specific extensions based on a demonstration of necessity for non-EGUs).

As the D.C. Circuit noted in *Wisconsin,* the good neighbor provision requires upwind states to ''eliminate their substantial contributions to downwind nonattainment in concert with the attainment deadlines'' in the downwind states, even where those attainment deadlines occur before EPA's statutory deadline under CAA section 110(c) to promulgate a FIP.[275]

Referencing the Supreme Court's description of the attainment deadlines as ''the heart'' of the CAA, the *Wisconsin* court noted that some deviation from the mandate to eliminate prohibited transport by downwind attainment deadlines may be allowed only ''under particular circumstances and upon a sufficient showing of necessity.''[276]

For the reasons provided in the following sub-sections, the EPA finds that installation of certain EGU controls and all non-EGU controls is not possible by the Moderate area attainment date for the 2015 ozone NAAQS (*i.e.,* August 3, 2024),[277] and, for certain sources, may not be possible by the 2026 ozone season or even the August 3, 2027, Serious area attainment date. While the EPA's technical analysis demonstrates that for any individual source, control installation could be accomplished by the start of the 2026 ozone season, in light of the scope of this rule coupled with current information on the present economic capacity of sources, control-installation vendors, and associated markets for labor and material, it is the EPA's judgment that a three-year timeframe is not possible for all sources subject to this rule collectively to come into compliance. Therefore, additional time beyond 2026 will be allowed for certain facilities in recognition of these constraints on the processes needed for installation of controls across all of the covered sources.

a. EGU Schedule for 2026 and Later Years

As discussed in sections V.B through V.D of this document, significant emissions reduction potential exists and is included in EPA's quantification of significant contribution based on the potential to install post-combustion controls (SCR and SNCRs) at EGUs. However, as discussed in detail in those sections, the assumption for installation of this technology on a region-wide scale is 36–48 months in this final rule. This amount of time allows for all necessary procurement, permitting, and installation milestones across multiple units in the covered region. Therefore, the EPA finds that these emissions reductions are not available any earlier than the 2026 compliance period. Starting in 2026, state emissions budgets will reflect full implementation of assumed SNCR mitigation measures and implementation of half the emissions reduction potential identified for assumed SCR mitigation measures. For each year in 2027 and beyond, state emissions budgets include all of the emissions reductions commensurate with these post-combustion control technologies identified for covered units in Step 3. The EPA notes that similar compliance schedules and post-combustion control retrofit installations have been realized successfully in prior programs allowing similar timeframes. Subsequent to the NO_X SIP Call and the parallel Finding of Significant Contribution and Rulemaking on Section 126 Petitions (which became effective December 28, 1998, and February 17, 2000, respectively[278]), nearly 19 GW of SCR retrofit came online in 2002 and another 42 GW of SCR retrofit came online for steam boilers in 2003, illustrating that a considerable volume of SCR retrofit capacity is possible within a 36-month period.

Comment: Some commenters disagreed with EPA's proposed 36-month timeframe for SCR retrofit. These commenters noted that, while possible at the unit or plant level, the collective volume of assumed SCR installation would not be possible given the labor constraints, supply constraints, and simultaneous outages necessary to complete SCR retrofit projects on such a schedule. They noted that many of the remaining coal units lacking SCR pose more site-specific installation challenges than those that were already retrofitted on a quicker timeframe.

Response: EPA is making several changes in this final rule to address these concerns. First, EPA is phasing in emissions reductions commensurate with assumed SCR installations consistent with a 36-to-48-month time frame in this final rule, instead of a 36-month time frame as proposed. EPA is implementing half of this emissions reduction potential in 2026 ozone-season NO_X budgets for states containing these EGUs and the other half of this emissions reduction potential in 2027 ozone-season NO_X budgets for those states. This phase-in approach to implementing SCR retrofit reduction potential over a three to four year period is in response to comments, including those from third-party full-service engineering firms. These commenters highlighted that while the

[274] 958 F.3d at 1203–1204 (remanding the EPA denial of section 126 petition based on the EPA analysis of downwind air quality in 2023 rather than 2021, the year containing the Marginal area attainment date).

[275] 938 F.3d at 317–318. For example, the court observed that the EPA may shorten the deadline for SIP submissions under CAA section 110(a)(1) and may issue FIPs soon thereafter under CAA section 110(c)(1), to align the upwind states' deadline for satisfying good neighbor obligations with the downwind states' deadline for attaining the NAAQS. *Id.* at 318.

[276] *Id.* at 316 and 319–320 (noting that any such deviation must be ''rooted in Title I's framework'' and ''provide a sufficient level of protection to downwind States'').

[277] Compliance by the August 3, 2021, Marginal area attainment date is also impossible as that date has passed.

[278] *See* 63 FR 57356 (October 27, 1998); 65 FR 2674 (January 18, 2000). The D.C. Circuit stayed the NO_X SIP Call by an order issued May 25, 1999. After upholding the rule in most respects in *Michigan* v. *EPA,* 213 F.3d 663 (D.C. Cir. 2000), the court lifted the stay by an order issued June 22, 2000.

proposed 36-month time frame is viable at the plant level, it would be ''very unlikely'' that the collective volume of SCR capacity could be installed in a three-year time frame based on a variety of factors. First, the commenters identified constraints on labor needed to retrofit 32 GW of capacity, highlighting that the Bureau of Labor and Statistics projects that there will be a decline in boilermaker employment over the decade and that the Associated Builders and Contractors (ABC) identifies the need for 650,000 additional skilled craft professionals on top of the normal hiring pace to meet the economy-wide demand created by infrastructure investment and other clean energy projects (*e.g.,* carbon capture and storage). They highlighted the decline in companies serving this type of large-scale retrofit project as the lack of new coal units and the retirement of coal units has curtailed activity in this area over the past five years. They also identified supply bottlenecks for key SCR components that would slow the ability to implement a large volume of SCR within 3 years, affecting electrical conduits, transformers, piping, structural and plate steel, and wire (with temporary price increases ranging from 30 percent to 200 percent). Finally, commenters note that site-specific conditions can make retrofits for individual units a lengthier process than historical averages (*e.g.,* under prior rules more accommodating sites retrofitted first) and that four years may be necessary for some projects, accordingly. EPA found the technical justification submitted in comment consistent with its prior assessments that a range of 39–48 months is appropriate for SCR-retrofit timing within regional-scale programs.[279] Therefore, EPA is adjusting the timeframe to still incentivize these reductions by the attainment date while accommodating the potential for some SCR retrofits to require between 36–48 months for installation.

Some commenters requested more than 48 months for SCR installation based on past projects that took five or more years. EPA disagrees with these commenters for two reasons. First, while EPA is identifying SCR retrofit potential to define significant contribution at Step 3, the rule only requires emissions reductions commensurate with that technology, implemented through a trading program, meaning that operators of EGUs eligible for SCR retrofit may pursue a variety of strategies for reducing emissions. Such compliance flexibility will accommodate extreme or unique circumstances in which a desired SCR retrofit is not achieved by the 2027 ozone season, although EPA finds such a circumstance exceedingly unlikely. Second, the historical examples that exceeded 48 months do not necessarily demonstrate that such projects are impossible to execute in less than 48 months, but rather that they can extend beyond that timeframe if no requirements or incentives are in place for a faster installation. As the D.C. Circuit has recognized, historical data on the amount of time sources have taken to install pollution controls do not in themselves establish the minimum amount of time in which those controls could be installed if sources are subject to a legal mandate to do so. *See Wisconsin,* 938 F.3d at 330 (''[A]ll those anecdotes show is that installation can drag on when companies are unconstrained by the ticking clock of the law.'').

[279] 86 FR 23102.

b. Non-EGU or Industrial Source Schedule for 2026 and Later Years

The EPA proposed to require that all emissions reductions associated with the requirements for non-EGU industrial sources go into effect by the start of the 2026 ozone season, but also requested comment on its control-installation timing estimates for non-EGUs and requested comment on the possibility of providing for limited compliance extensions based on a showing of necessity. *See* 87 FR 20104–05.

Comment: The EPA received numerous comments regarding the inability of various non-EGU industries to install controls to comply with the emissions limits by 2026. Specifically, commenters raised concerns regarding the ability to meet these deadlines due to the ongoing geopolitical instability triggered by the war in Ukraine, COVID–19 pandemic-driven disruptions, and supply chain delays and shortages. Commenters also claimed that the EPA's three-year installation timeframe for non-EGUs does not account for the time needed to obtain necessary permits. Commenters stated that even where controls are feasible for a source, some sources would need to shut down due to their inability to install controls by 2026 and requested that the EPA provide additional time for sources to come into compliance. Commenters from multiple non-EGU industries stated that the proposed applicability criteria will require controls to be installed on thousands of non-EGU emissions units. Because of the number of emissions units, commenters raised concerns with permitting delays and the unavailability of skilled labor and necessary components. Commenters suggested various timelines for control installation timing ranging from one additional year to seven years. Other commenters asserted that the data supported the conclusion that all non-EGU sources, or at least some non-EGU sources, could install controls by 2026 or earlier, and that EPA has a legal obligation to impose good neighbor requirements as expeditiously as practicable by such sources, including earlier than 2026 if possible.

Response: After reviewing the information received during the public comment period and the additional information presented in the Non-EGU Control Installation Timing Report, the EPA has concluded that the majority of non-EGUs can install and operate the required controls by the 2026 ozone season. For the non-EGU control requirements on which the EPA has based its Step 3 findings as described in section V of this document, the emissions limits will generally go into effect starting with the 2026 ozone season (except where an individual source qualifies for a limited extension of time to comply based on a specific demonstration of necessity, as described in this section). The EPA finds that meeting the emissions limitations of this final rule through installation of necessary controls by an ozone season before 2026 is not expected to be possible for the industrial sources covered by this final rule.

The EPA recognizes that labor shortages, supply shortages, or other circumstances beyond the control of source owner/operators may, in some cases, render compliance by 2026 impossible for a particular industrial source. Therefore, the final rule contains provisions allowing source owner/operators to request limited compliance extensions based on a case-by-case demonstration of necessity. Under these provisions, the owner or operator of a source may initially apply for an extension of up to one year to comply with the applicable emissions control requirements, which if approved by the EPA, would require compliance no later than the 2027 ozone season. The EPA may grant an additional case-based extension of up to two additional years for full compliance, where specific criteria are met.

The EPA initiated a study to examine the time necessary to install the potential controls identified in the final rule's cost analysis for all of the non-EGU industries subject to the final rule, including SNCR, low NO_X burners, layered combustion, NSCR, SCR, fluid gas recirculation, and SNCR/advanced selective noncatalytic reduction

(ASNCR). The resulting report, which we refer to as the ''Non-EGU Control Installation Timing Report,'' identified a range of estimated installation times with minimum estimated installation times ranging from 6–27 months without any supply chain delays and 6–40 months with potential supply chain delays depending on the industry.[280] The Non-EGU Control Installation Timing Report also identified maximum estimated installation times ranging from 12–28 months without any supply chain delays and 12–72 months with potential supply chain delays depending on the industry. As indicated in the Non-EGU Control Installation Timing Report, the installation of layered combustion and NSCR control technology, in particular, could take between 9 and 72 months depending on supply chain delays.[281] The report also indicated that permitting processes may take 6 to 12 months but noted that these processes typically can proceed concurrent with other steps of the installation process.[282]

We find that the potential time needed for permitting processes is generally unlikely to significantly affect installation timeframes of at least three years given that a source that has three or more years to comply is expected, in most cases, to have adequate time to apply for and secure the necessary permits during that time. Permitting processes may, however, impact shorter installation times ranging from 12–28 months. Given the 12–28 month estimate for minimum and maximum installation times without supply chain delays and permitting timeframes typically ranging from 6–12 months, the EPA finds that the controls for non-EGU sources needed to comply with this final rule are generally not expected to be installed significantly before the 2026 ozone season.

Generally, the Non-EGU Control Installation Timing Report indicated that all non-EGU unit types subject to the final rule could install controls within 28 months if there are no supply chain delays. Thus, the Non-EGU Control Installation Timing Report confirms that for any individual facility, meeting the emissions limitations of this final rule through installation of controls can be completed by the start of the 2026 ozone season. It is only when the number of units in the U.S. potentially affected by the rule is taken into account, coupled with broader considerations of economic capacity including current information on supply-chain delays, that the potential need for additional time beyond 2026 becomes a possibility. Under ideal economic conditions (*i.e.,* no supply-chain delays or other constraints), affected units are estimated to be capable to install both combustion and post-combustion controls before the 2026 ozone season. Many commenters, however, provided information on installation timing estimates based on current supply chain delays and labor constraints. These commenters generally stated that installation of the necessary controls for some units would take longer than three years if supply chain delays similar to those that have occurred over the past few years continue. The Non-EGU Control Installation Timing Report reflected this information, together with additional information gathered from pollution control vendors, to develop ranges of estimates of possible installation times given current (*i.e.,* 2022) labor market conditions and material supplies. The Non-EGU Control Installation Timing Report also discussed how the installation and optimization of post-combustion controls over a similar timeframe at both EGUs and non-EGUs subject to this final rule would, considered cumulatively, potentially affect the installation timing needs of the covered non-EGU sources.

Based on information provided by commenters and vendors, the Non-EGU Control Installation Timing Report indicated that if current supply chain delays continue, control installations could take as long as 61 months for most non-EGU industries and possibly as long as 64–112 months in difficult cases. Notably, however, the conclusions in the Non-EGU Control Installation Timing Report reflect three key assumptions that could result in the relatively lengthy timing estimates at the outer end of this range: (1) the current state of supply chain delays and disruptions would continue without any increase in labor supply, materials, or reduction in fabrication timing; (2) the labor and materials markets would not adjust in response to this rule in the timeframe needed to meet the increased demand for control installations; and (3) the Report was unable to account for some of the flexibilities built into the final rule that will allow owners and operators to install controls on the most cost-effective units with shorter installation times.

As presented in the Non-EGU Control Installation Timing Report, supply chain delays and disruptions have generally been lessening since they peaked in 2020 during the COVID–19 pandemic, and many economic indicators have showed some improvement towards pre-pandemic levels, including freight transportation, inventory to sales ratios, interstate miles traveled, U.S. goods imports, and supply chain indices.[283] If these economic indicators continue to improve and the availability of fabricators and materials continues to trend upward, the control timing estimates identified in the Non-EGU Control Installation Timing Report could prove to be overstated for some industries and control technologies. In addition, the Non-EGU Control Installation Timing Report did not account for the labor and supply market adjustments that would be anticipated to occur to meet increased demand for control technologies and related materials and labor over the next several years in response to the rule. *Cf. Wisconsin,* 938 F.3d at 330 (''[A]ll those anecdotes [of elongated control installation times] show is that installation can drag on when companies are unconstrained by the ticking clock of the law.''). For example, some of the longer installation timeframes identified in the Non-EGU Control Installation Timing Report are based on assumed limits on the current availability of skilled labor needed to install combustion controls and post combustion controls. If the market adjusts in response to increasing demand for this type of skilled labor in the timeframe needed for compliance (*e.g.,* there is an increase in boilermaker and engine controls labor), the installation timing estimates in the Non-EGU Control Installation Timing Report again could be overstated.

The Non-EGU Control Installation Timing Report also did not account for flexibilities provided in this final rule that will enable owners and operators of certain affected units to identify the most cost-effective and efficient means for installing any necessary controls. For example, one concern highlighted by commenters was the amount of time necessary to install controls on engines that have been in operation for 50 or more years. The requirements that we are finalizing for engines in the Pipeline Transportation of Natural Gas industry include an exemption for emergency engines and provisions allowing source owner/operators to request the EPA approval of facility-wide emissions averaging plans, both of which enable owners and operators of affected units to take costs, installation timing needs,

[280] *See generally* SC&A, *NO_X Emission Control Technology Installation Timing for Non-EGU Sources* (March 14, 2023) (''Non-EGU Control Installation Timing Report'').

[281] *See* Non-EGU Control Installation Timing Report, Executive Summary (March 14, 2023).

[282] Id. at Section 5.6.

[283] Id. at Section 6.1.

and other considerations into account in deciding which engines to control.

In response to industry concern about the number and size of units captured by the proposed applicability criteria, the EPA has made several changes to the applicability criteria in the final rule to focus the control requirements on impactful non-EGU units. As explained further in section VI.C of this document, the EPA is establishing exemptions for low-use boilers and engines where it would not be cost-effective to require controls at this time. Finally, as discussed in section VI.C.3 of this document, the EPA is not finalizing the proposed requirements for most emissions unit types in the Iron and Steel Mills and Ferroalloy Manufacturing industry given the EPA does not currently have a sufficient technical basis for finalizing those proposed requirements. These changes reduce the number of non-EGU units that will actually need to install controls and should reduce the strain on the labor and supply chain and permitting processes. For example, for engines, the EPA estimates that the facility-wide emissions averaging provision would, in many cases, allow facilities to install controls on only one-third of their engines, on average (see section VI.C.1 of this document for further discussion).

Taking all of these considerations into account, the EPA finds that the outer range of timing estimates presented in the Non-EGU Control Installation Timing Report generally reflects a conservative set of installation timing estimates and that the factors described previously could result in installation timeframes that fall toward the shorter end of the ranges of time that factor in supply-chain delays or could obviate those supply-chain delay issues entirely.

Based on all of these considerations, the EPA has concluded that three years is generally an adequate amount of time for the non-EGU sources covered by this final rule to install the controls in the 20 states that remain linked in 2026. The EPA also recognizes, however, that some sources may not be able to install controls by the 2026 ozone season despite making good faith efforts to do so, due to the aforementioned supply chain delays or other circumstances entirely beyond the owner or operator's control. Therefore, the final FIPs require compliance with the emissions control requirements for non-EGUs by the beginning of the 2026 ozone season, with limited exceptions based on a showing of necessity for individual sources that meet specific criteria. Where an individual owner or operator submits a satisfactory demonstration that an extension of time to comply is necessary, due to circumstances entirely beyond the owner or operator's control and despite all good faith efforts to install the necessary controls by May 1, 2026, the EPA may determine that installation by 2026 is not possible and thereby grant an extension of up to one year for that source to fully implement the required controls. If, after the EPA has granted a request for an initial compliance extension, the source remains unable to comply by the extended compliance date due to circumstances entirely beyond the owner or operator's control and despite all good faith efforts to install the necessary controls by the extended compliance date, the owner or operator may request and the EPA may grant a second extension of up to two additional years for full compliance, where specific criteria are met. This application process is generally in accordance with the concept on which the Agency requested comment in the proposal, *see* 87 FR 20104–05, and is modeled on a similar process provided for industrial sources subject to CAA section 112 NESHAPs, found at 40 CFR 63.6(i)(3).

The EPA intends to grant a request for an initial compliance extension only where a source demonstrates that it has taken all steps possible to install the necessary controls by the applicable compliance date and still cannot comply by the 2026 ozone season, due to circumstances entirely beyond its control. Any request for a compliance extension must be received by the EPA at least 180 days before the May 1, 2026, compliance date. The request must include all information obtained from control technology vendors demonstrating that the necessary controls cannot be installed by the applicable compliance date, any permit(s) secured for the installation of controls or information from the permitting authority on the timeline for issuance of such permit(s) if the source has not yet obtained the required permit(s); and any contracts entered into by the source for the installation of the control technology or an explanation as to why no contract is necessary. The EPA may also consider documentation of a source owner's/operator's plans to shut down a source by the 2027 ozone season in determining whether a source is eligible for a compliance extension. The owner or operator of an affected unit remains subject to the May 1, 2026 compliance date unless and until the Administrator grants a compliance extension.

The EPA intends to grant a request for a second compliance extension beyond 2027 only where a source owner/operator submits updated documentation showing that it is not possible to install and operate controls by the 2027 ozone season, despite all good faith efforts to comply and due to circumstances entirely beyond its control. The request must be received by the EPA at least 180 days before the extended compliance date and must include, at minimum, the same types of information as that required for the initial extension request. The owner or operator of an affected unit remains subject to the initial extended compliance date unless and until the Administrator grants a second compliance extension. A denial will be effective on the date of denial.

As discussed earlier in section VI.A, in *Wisconsin* the court held that some deviation from the CAA's mandate to eliminate prohibited transport by downwind attainment deadlines may be allowed only ''under particular circumstances and upon a sufficient showing of necessity.'' [284] This standard is met when, in the EPA's judgment, compliance by the attainment date amounts to an impossibility. The EPA cannot allow a covered industrial source to avoid timely compliance with the emissions control requirements established in this final rule unless the source owner/operator can demonstrate that compliance by the 2026 ozone season is not possible due to circumstances entirely beyond their control. The criteria that must be met to qualify for limited extensions of time to comply are designed to meet this statutory mandate. The EPA anticipates that the majority of the industrial sources covered by this final rule will not qualify for a compliance extension.

B. Regulatory Requirements for EGUs

To implement the required emissions reductions from EGUs, the EPA is revising the existing CSAPR NO_X Ozone Season Group 3 Trading Program (the ''Group 3 trading program'') established in the Revised CSAPR Update both to expand the program's geographic scope and to enhance the program's ability to ensure favorable environmental outcomes. The EPA is using a trading program for EGUs because of the inherently greater flexibility that a trading program can provide relative to more prescriptive, ''command-and-control'' forms of regulation of sufficient stringency to achieve the necessary emissions reductions. In the electric

[284] *Wisconsin,* 938 F.3d at 316 and 319–320 (noting that any such deviation must be ''rooted in Title I's framework'' and ''provide a sufficient level of protection to downwind States'').

power sector, EGUs' extensive interconnectedness and coordination create the ability to shift both electricity production and emissions among units, providing a closely related ability to achieve emissions reductions in part by shifting electricity production from higher-emitting units to lower-emitting or non-emitting units. Thus, while the Step 3 control-stringency determination for EGUs to eliminate significant contribution is based on strategies that do not require generation shifting or reduced utilization of EGUs, the sector's 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. In addition, it is essential for the electric power sector to retain short-term operational flexibility sufficient to allow electricity to be produced at all times in the quantities needed to meet demand simultaneously, and the flexibility of a trading program can be helpful in supporting this aspect of the industry as well.

To ensure emissions reductions necessary to eliminate significant contribution are maintained, in this rulemaking, the EPA is making certain enhancements to the current provisions of the Group 3 trading program addressing emissions-control performance by some kinds of individual units that will necessarily reduce the flexibility of the program to some extent for those units. In analyzing significant contribution at Step 3, once a linkage has been established between an upwind state and a downwind receptor, we identify an appropriate set of emissions control strategies, considering cost and other factors, that would eliminate significant contribution from the upwind state without leading to undercontrol or overcontrol at the downwind linked receptors. At Step 4, for EGUs, we develop emissions budgets based on consistent application of the identified strategies to the sources. This level of emission control at each source identified in Step 3 is what the EPA deems to eliminate significant contribution, while the design of emission budgets that successfully implement that level of emission control is determined at Step 4. See section III.B and V.

The trading program enhancements discussed in this section are designed to ensure that sources actually achieve that level of emission control and thereby eliminate significant contribution on a permanent basis at Step 4. The enhancements ensure that the emissions budgets for EGUs continue to secure the level of emission control identified at Step 3 at the sources active in the trading program on a more consistent basis throughout each ozone season than prior transport trading programs (including those that did not provide complete remedies for interstate pollution transport) have required. An alternative form of implementation at Step 4 would be to implement source-specific emissions limitations (*e.g.,* rate-based standards expressed as mass per unit of heat input) reflecting the control strategies identified at Step 3. This is a very common form of implementation for many other CAA requirements and is indeed the manner of implementation selected in this very rulemaking for other affected industrial sources. See sections III.B, V.D.4, and VI.C. But doing so would require loss of the flexibilities inherent in a trading program, inclusive of these enhancements, that facilitate orderly and timely achievement of the required emission reductions in the power sector.

Prior to this rule, the Group 3 trading program has applied to EGUs meeting the program's applicability criteria within the borders of twelve states: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. Affected EGUs in these twelve states will continue to participate in the Group 3 trading program as revised in this rulemaking, with some revised provisions taking effect in the 2023 control period and other revised provisions taking effect later as discussed elsewhere in this document. The EPA is expanding the Group 3 trading program's geographic scope to include all of the additional states for which EGU emissions reduction requirements are being established in this rulemaking. Affected EGUs within the borders of seven states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program (the "Group 2 trading program")—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin—will transition from the Group 2 trading program to the revised Group 3 trading program at the beginning of the 2023 control period,[285] and affected EGUs within the borders of the three states not currently covered by any CSAPR trading program for seasonal NO_X emissions—Minnesota, Nevada, and Utah—will enter the Group 3 trading program in the 2023 control period on the effective date of this rule.

[285] Affected EGUs in the three other states currently covered by the Group 2 trading program—Iowa, Kansas, and Tennessee—will continue to participate in that program.

As discussed in section VI.B.12.a of this document, because the effective date of the rule will likely be sometime during the 2023 ozone season, special transitional provisions have been developed to allow for efficient administration of the rule's EGU requirements through the Group 3 trading program while not imposing any new substantive obligations on parties prior to the rule's effective date, similar to the transitional provisions implemented under the Revised CSAPR Update.

As is the case for the states already in the Group 3 trading program, for each state added to the program, the set of affected EGUs will include new units as well as existing units and will also include units located in Indian country within the state's borders. Sections VI.B.2 and VI.B.3 of this rule provide additional discussion of the geographic expansion of the Group 3 trading program and the units in the expanded geography that will become subject to the program under the program's existing applicability provisions.

In addition to expanding the Group 3 trading program's geographic scope, the EPA is modifying the program's regulations prospectively to include certain enhancements to improve environmental outcomes. Two of the proposed enhancements will adjust the overall quantities of allowances available for compliance in the trading program in each control period so as to maintain the rule's selected control stringency and related EGU effective emissions rate performance level as the EGU fleet evolves. First, instead of establishing emissions budgets for all future years under the program at the time of the rulemaking, which cannot reflect future changes in the EGU fleet unknown at the time of the rulemaking, the EPA is revising the trading program regulations to include a dynamic budgeting procedure. Under this procedure, the EPA will calculate emissions budgets for control periods in 2026 and later years based on more current information about the composition and utilization of the EGU fleet, specifically data available from the 2024 ozone season and following (*e.g.,* for 2026, data from periods through 2024; for 2027, data from periods through 2025; etc.). Through the 2029 control period, the dynamically determined budgets will apply only if they are higher than preset budgets established in the rule. (Associated revisions to the program's variability limits and unit-level allowance allocation procedures will coordinate these provisions with the revised budget-setting procedures.) Second, starting with the 2024 control period, the EPA will annually recalibrate the quantity of accumulated banked allowances under the program to prevent the quantity of allowances carried over from each control period to the next from exceeding the target bank level, which would be revised to represent a preset percentage of the sum of the state emissions budgets for each control period. The preset percentage will be 21 percent for control periods through 2029 and 10.5 percent for control periods in 2030 and later years. Together, these enhancements will protect the intended stringency of the trading program against potential erosion caused by EGU fleet turnover and will better sustain over time the incentives created by the trading program to achieve the degree of emissions control for EGUs that the EPA has determined is necessary to address states' good neighbor obligations.

Two further enhancements to the Group 3 trading program establish provisions designed to promote more consistent emissions control by individual EGUs within the context of the trading program. First, starting with the 2024 control period for coal-fired EGUs with existing SCR controls and the earlier of the 2030 control period or the control period after which an SCR is installed for other large coal-fired EGUs, a daily NO_X emissions rate of 0.14 lb/mmBtu will apply as a backstop to the seasonal emissions budgets (which are based on an assumed seasonal average emissions rate of 0.08 lb/mmBtu for EGUs with existing SCR controls). Each ton of emissions exceeding a unit's backstop daily emissions rate, after the first 50 such tons, in a given control period will incur a 3-for-1 allowance surrender ratio instead of the usual 1-for-1 allowance surrender ratio. Second, also starting with the 2024 control period, the trading program's existing assurance provisions, which require extra allowance surrenders from sources that are found responsible for contributing to an exceedance of the relevant state's ''assurance level'' (*i.e.,* typically 121 percent of the state's emissions budget), will be strengthened by the addition of another backstop requirement. Specifically, for any unit equipped with post-combustion controls that is found responsible for contributing to an exceedance of the state's assurance level, the revised regulations will prohibit the unit's seasonal emissions from exceeding by more than 50 tons the emissions that would have resulted if the unit had achieved a seasonal average emissions rate equal to the higher of 0.10 lb/mmBtu or 125 percent of the unit's lowest previous seasonal average emissions rate under any CSAPR seasonal NO_X trading program.[286]

These two enhancements are designed to ensure that all individual units with SCR controls have strong incentives to continuously operate and optimize their controls, and also to ensure that all units with post-combustion controls have strong incentives to optimize their emissions performance when a state's assurance level might otherwise be exceeded. These enhancements are generally designed to ensure consistency with the EPA's determination regarding the emissions control stringency needed from EGUs to eliminate significant contribution under the Step 3 multifactor analysis as discussed in section V of this document. Further, these enhancements are designed to provide greater assurance that emissions controls will be operated on all days of the ozone season and therefore necessarily on the days that turn out to be most critical for downwind ozone levels. The EPA expects that promoting more consistently good emissions performance by individual EGUs will better ensure that each state's significant contribution is fully eliminated by this action, *see North Carolina,* 531 F.3d at 919–21. In addition to addressing the statutory requirements of eliminating significant contribution, the EPA anticipates that these enhancements will also deliver public health and environmental benefits to underserved and overburdened communities.

The revisions to the Group 3 trading program being finalized in this rule are very similar to the proposed revisions. The changes from proposal to the set of states covered are driven largely by updates to the air quality modeling performed for the final rule, as described in section IV of this document. The changes from proposal to the trading program enhancements are generally being made in response to comments on the proposal, as discussed in more detail in the remainder of section VI.B of this document.

[286] The requirement would not apply for control periods during which the unit operated for less than 10 percent of the hours, and emissions rates achieved in such previous control periods would be excluded from the comparison.

1. Trading Program Background and Overview of Revisions

a. Current CSAPR Trading Program Design Elements and Identified Concerns

The use of allowance trading programs to achieve required emissions reductions from the electric power sector has a long history, rooted in the Clean Air Act Amendments of 1990. In Title IV of those amendments, Congress specified the design elements for a 48-state allowance trading program to reduce SO_2 emissions and the resulting acid precipitation. Building on the success of that first allowance trading program as a tool for addressing multi-state air pollution issues, since 1998 EPA has promulgated and implemented multiple allowance trading programs for SO_2 or NO_X emissions to address the requirements of the CAA's good neighbor provision with respect to successively more protective NAAQS for fine particulate matter and ozone. Most of these trading programs have applied either exclusively or primarily to EGUs.

The EPA currently administers six CSAPR trading programs for EGUs (promulgated in CSAPR, the CSAPR Update, and the Revised CSAPR Update) that differ in the pollutants, geographic regions, and time periods covered and in the levels of stringency, but that otherwise have been nearly identical in their core design elements and their regulatory text.[287] The principal common design elements currently reflected in all of the programs are as follows:

- An ''emissions budget'' is established for each state for each control period, representing the EPA's quantification of the emissions that would remain under certain projected conditions after elimination of the emissions prohibited by the good neighbor provision under those projected conditions. For each control period of program operation, a quantity of newly issued ''allowances'' equal to the amount of each state's emissions budget is allocated among the state's sources. (States have options to replace the EPA's default allocations or to institute an auction process.) Total emissions in a given control period from all sources in the program are effectively

[287] The six current CSAPR trading programs are the CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR SO_2 Group 1 Trading Program, CSAPR SO_2 Group 2 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, and CSAPR NO_X Ozone Season Group 3 Trading Program. The regulations for the six programs are set forth at subparts AAAAA, BBBBB, CCCCC, DDDDD, EEEEE, and GGGGG, respectively, of 40 CFR part 97.

capped at a level no higher than the total quantity of allowances available for use in the control period, consisting of the sum of all states' emissions budgets for the control period plus any unused allowances carried over from previous control periods as ''banked'' allowances.

- ''Assurance provisions'' in each program establish an ''assurance level'' for each state for each control period, defined as the sum of the state's emissions budget plus a specified ''variability limit.'' The purpose of the assurance provisions is to limit the total emissions from each state's sources in each control period to an amount close to the state's emissions budget for the control period, consistent with the good neighbor provision's mandate that required emissions reductions must be achieved within the state, while allowing some flexibility beyond the emissions budget to accommodate year-to-year operational variability. In the event a state's assurance level is exceeded, responsibility for the exceedance is apportioned among the state's sources through a procedure that accounts for the sources' shares of the state's total emissions for the control period as well as the sources' shares of the state's assurance level for the control period.
- At the program's compliance deadlines after each control period, sources are required to hold for surrender specified quantities of allowances. The minimum quantities of allowances that must be surrendered are based on the sources' reported emissions for the control period at a 1-for-1 ratio of allowances to tons of emissions (or 2-for-1 in instances of late compliance). In addition, two more allowances must be surrendered for each ton of emissions exceeding a state's assurance level for a control period, yielding an overall 3-for-1 surrender ratio for those emissions (or 4-for-1 in instances of late compliance). Failure to timely surrender all required allowances is potentially subject to penalties under the CAA's enforcement provisions.
- To continuously incentivize sources to reduce their emissions even when they already hold sufficient allowances to cover their expected emissions for a control period, and to promote compliance cost minimization, operational flexibility, and allowance market liquidity, the programs allow trading of allowances—both among sources in the program and with non-source entities—and also let allowances that are unused in one control period be carried over for use in future control periods as banked allowances. Although the CSAPR programs do not limit trading of allowances, and prior to this rule have not limited banking of allowances within a given trading program, the 3-for-1 surrender ratio imposed by the assurance provisions on any emissions exceeding a state's assurance level disincentivizes sources from relying on either in-state banked allowances or net out-of-state purchased allowances to emit over the assurance level.[288]
- Finally, other common design elements ensure program integrity, source accountability, and administrative transparency. Most notably, each unit must monitor and report emissions and operational data in accordance with the provisions of 40 CFR part 75; all allowance allocations or auction results, transfers, and deductions must be properly recorded in the EPA's Allowance Management System; each source must have a designated representative who is authorized to represent all of the source's owners and operators and is responsible for certifying the accuracy of the source's reports to the EPA and overseeing the source's Allowance Management System account; and comprehensive data on emissions and allowances are made publicly available.

The EPA continues to believe that the historical CSAPR trading program structure established by the common design elements just described has important positive attributes, particularly with respect to the exceptional degree of compliance flexibility it can provide to a sector such as the electric power sector where such flexibility is especially useful and valuable. However, the EPA also shares many stakeholders' concerns about whether the historical structure, without enhancements, is capable of adequately addressing states' good neighbor obligations with respect to the 2015 ozone NAAQS in light of the rapidly evolving EGU fleet and the protectiveness and short-term form of the ozone standard. One set of concerns relates to the historically observed tendency under the trading programs for the supply of allowances to grow over time while the demand for allowances falls, reducing allowance prices and eroding the consequent incentives for sources to effectively control their emissions. A second, overlapping set of concerns relates to the general absence of source- or unit-specific emissions reduction requirements, allowing some individual sources to idle or run less optimally existing emissions controls even when a linkage between the sources' state and a receptor persists. For example, certain units in Ohio and Pennsylvania have been found to have operated their controls below target emissions performance levels used for budget setting under the CSAPR Update in the 2019–2021 period, even though the Revised CSAPR Update found that these states remained linked through at least 2021 to receptors for the 2008 ozone NAAQS, and the CSAPR Update itself was only a partial remedy. *See* 86 FR 23071, 23083. While this unit-level behavior may have been permissible under the prior program, emissions from these individual sources can contribute to increased pollution concentrations downwind on the particular days that matter for downwind exceedances of the relevant air quality standard. This indicates that the prior program design was not effectively ensuring the elimination of significant contribution.[289]

The EPA has analyzed hourly emissions data reported in prior cap-and-trade programs and identified instances of sources that did not operate SCR controls for substantial portions of recent ozone seasons. In an effort to ensure emissions control on critically important highest ozone days, guard against non-operation of emissions controls under a more protective NAAQS, and provide assurance of elimination of significant contribution to downwind areas, while also maintaining appropriate compliance and operational flexibility for EGUs, the EPA in this rule is implementing a suite of enhancements to the trading program. These will help to ensure reductions occur on the highest ozone days commensurate with our Step 3 determinations, in addition to maintaining a mass-based seasonal requirement. To meet the statutory mandate to eliminate significant contribution and interference with

[288] As discussed in section VI.B.6 of this document, while allowance banking has not previously been limited under any of the CSAPR trading programs, limits on the use of banked allowances were included in the earlier NO_X Budget Trading Program in the form of ''flow control'' provisions.

[289] We also observe that these sources' emissions have the potential to impact downwind overburdened communities. *See* Ozone Transport Policy Analysis Final Rule TSD, Section E. The EPA conducted a screening-level analysis to determine whether there may be impacts on overburdened communities resulting from those EGUs receiving backstop emissions rates under this rule. This analysis identified a greater potential for these sources to affect areas of potential concern than the national coal-fired EGU fleet on average. However, this analysis is distinct from the more comprehensive exposure analysis conducted as discussed in section VII of this document and the RIA. In addition, we note that our conclusions regarding the EGU trading program enhancements in this final rule are wholly supportable and justified under the good neighbor provision, even in the absence of any potential benefits to overburdened communities.

maintenance on the critically important days, this combination of provisions will strongly incentivize sources to plan to run controls all season, including on the highest ozone days, while giving reasonable flexibility for occasional operational needs.[290]

In this rulemaking, the EPA is revising the Group 3 trading program to include enhancements designed to address both sets of concerns described previously. The principles guiding the various revisions and the relationships of the revisions to one another are discussed in sections VI.B.1.b and VI.B.1.c of this document. The individual revisions are discussed in more detail in sections VI.B.4 through VI.B.9 of this document.

b. Enhancements To Maintain Selected Control Stringency Over Time

The first set of concerns noted about the current CSAPR trading program structure relates to the programs' ability to maintain the rule's selected control stringency and related EGU effective emissions performance level as the EGU fleet evolves over time. Under the historical structure of the CSAPR trading programs, the effectiveness of the programs at maintaining the rule's selected control stringency depends entirely on how allowance prices over time compare to the costs of sources' various emissions reduction opportunities, which in turn depends on the relationship between the supply for allowances and the demand for allowances. In considering possible ways to address concerns about the ability to enhance the historical trading program structure to better sustain incentives to control emissions over time, the EPA has focused on the trading program design elements that determine the supply of allowances, specifically the approach for setting state emissions budgets and the rules concerning the carryover of unused allowances for use in future control periods as banked allowances.

i. Revised Emissions Budget-Setting Process

In each of the previous rulemakings establishing CSAPR trading programs, the EPA has evaluated the emissions that could be eliminated through implementation of certain types of emissions control strategies available at various cost thresholds to achieve certain rates of emissions per unit of heat input (*i.e.,* the amount of fuel consumed) and the effects of the resulting emissions reductions on downwind air quality. After determining the emissions control strategies and associated emissions reductions that should be required under the good neighbor provision by considering these factors in a multifactor test at Step 3, the EPA has then for purposes of Step 4 implementation program design projected the amounts of emissions that would remain after the assumed implementation of the selected emissions control strategies at various points in the future and has established the projected remaining amounts of emissions as the state emissions budgets in trading programs.

Projecting the amounts of emissions remaining after implementation of selected emissions controls necessarily requires projections not only for sources' future emissions rates but also for other factors that influence total emissions, notably the composition of the future EGU fleet (*i.e.,* the capacity amounts of different types of sources with different emissions rates) and their future utilization levels (*i.e.,* their heat input). To the extent conditions unfold in practice that differ from the projections made at the time of a rulemaking for these other factors, over time the emissions budgets may not reflect the intended stringency of the emissions control strategies identified in the rulemaking as consistent with addressing states' good neighbor obligations. Further, projecting EGU fleet composition and utilization beyond the relatively near-term analytic years of 2023 and 2026 given particular attention in this rulemaking has become increasingly challenging in light of the anticipated continued evolution of the electric power sector toward more efficient and cleaner sources of generation, including as driven by incentives provided by the Infrastructure Investment and Jobs Act as well as the Inflation Reduction Act.

A consequence of using a trading program approach with preset emissions budgets that do not keep pace with the trends in EGU fleet composition and heat input is that the preset emissions budgets maintain the supply of allowances at levels that increasingly exceed the emissions that would occur even without implementation of the emissions control strategies used as the basis for determining the emissions budgets, causing decreases in allowance prices and hence the incentives to implement the control strategies. As an example, although the emissions budgets in the CSAPR Update established in 2016 reflected implementation of the emissions control strategy of operating and optimizing existing SCR controls, within four years the EPA found that EGU retirements and changes in utilization not anticipated in EPA's previous budget-setting computations had made it economically attractive for at least some sources to idle or reduce the effectiveness of their existing controls (relying on purchased allowances instead).[291] While the EPA has provided analysis indicating that, on average, sources operate their controls more effectively on high electric demand days, it has also identified cases where units fail to optimize their controls on these days. Downwind states have suggested this type of reduced pollution control performance has occurred on the day and preceding day of an ozone exceedance.[292] [293] While the EPA had previously provided analysis focusing on the year of initial program implementation, when allowance prices were high (*i.e.,* 2017 for the CSAPR Update), to demonstrate that on average, sources operate their controls more effectively on high electric demand days, even in that case it had identified situations where particular units failed to optimize their controls on these days. In later years, when allowance prices had fallen, more sources, including some identified by commenters, had idled or reduced the effectiveness of their controls. Such an outcome undermined the ongoing achievement of emissions rate performance consistent with the control strategies identified in the CSAPR Update to eliminate significant contribution to nonattainment and interference with maintenance, despite the fact that the mass-based budgets were being met.

In the Revised CSAPR Update, the EPA took steps to better address the rapid evolution of the EGU fleet, specifically by setting updated emissions budgets for individual future

[290] Deferral of the backstop daily emissions rate for certain EGUs, for reasons discussed in section VI.B.7 of this document, does not alter this finding that this trading program enhancement is an important part of the solution to eliminating significant contribution from EGUs under CAA section 110(a)(2)(D)(i)(I).

[291] The price of allowances in CSAPR Update states started at levels near $800 per ton in 2017 but declined to less than $100 per ton by 2019 and were less than $70 per ton in July 2020 (data from S&P Global Market Intelligence).

[292] 86 FR 23117.

[293] *See* EPA–HQ–OAR–2020–0272–0094 (''[This] is demonstrated through examination of Maryland's ozone design value days for June 26th–28th, 2019. On those days, Maryland recorded 8-hour ozone levels of 75, 85 and 83 ppb at the Edgewood monitor. Maryland Department of the Environment evaluated the daily NO_X emission rate for units in Pennsylvania that were found to influence the design values on the 3 exceedance days (and 1 day prior to the exceedance) against the past-best ozone season 30-day rolling average optimized NO_X rate (which tends to be higher than the absolute lowest seasonal average rate).'').

years though 2024 that reflect future EGU fleet changes known with reasonable certainty at the time of the rulemaking. Some commenters in that rulemaking requested that the EPA also update the year-by-year emissions budgets to reflect future fleet changes that might become known after the time of the rulemaking, but the EPA declined to do so, in part because no methodology for making future emissions budget adjustments in response to post-rulemaking data had been included in the proposal for the rulemaking.

Based on information available as of December 2022, it appears that the emissions budgets set for the first two control periods covered by the Revised CSAPR Update generally succeeded at creating incentives to operate emissions controls under the Group 3 trading program for those control periods. However, the EPA recognizes that the lack of emissions budget adjustments after 2024 in conjunction with industry trends toward more efficient and cleaner resources will likely lead to a surplus of allowances after the adjustments end. This prospect for the existing Group 3 trading program should be avoided by the changes being made in this rulemaking. In this rulemaking, besides establishing new preset emissions budgets for the 2023 through 2029 control periods, the EPA is also extending the Group 3 trading program budget-setting methodology used in the Revised CSAPR Update to routinely calculate dynamic emissions budgets for each future control period from 2026 on, to be published in the year before that control period, with each dynamic emissions budget generally reflecting the latest available information on the composition and utilization of the EGU fleet at the time that dynamic emissions budget is determined. For the control periods in 2026 through 2029, each state's final emissions budget will be the preset budget determined for the state in this rulemaking except in instances when the dynamic budget determined for the state (and published approximately one year before the control period using the dynamic budget-setting methodology) is higher. For control periods in 2030 and thereafter, the emissions budgets will be the amounts determined for each state in the year before the control period using the dynamic budget-setting methodology.

The current budget-setting methodology established in the Revised CSAPR Update and the revisions being made to that methodology are discussed in detail in section VI.B.4 of this document and the Ozone Transport Policy Analysis Final Rule TSD. To summarize here, the methodology used to determine the preset budgets largely follows the Revised CSAPR Update's emissions budget-setting methodology, which included three primary steps: (1) establishment of a baseline inventory of EGUs adjusted for known retirements and new units, with heat input and emissions rate data for each EGU in the inventory based on recent historical data; (2) adjustment of the baseline data to reflect assumed emissions rate changes resulting from known new controls, known gas conversions, and implementation of the emissions control strategies used to determine states' good neighbor obligations; and (3) application of an increment or decrement to reflect the effect on emissions from projected generation shifting among the units in a state at the emissions reduction cost associated with the selected emissions control strategies. In this rulemaking, the EPA has determined the preset state emissions budgets for the control periods from 2023 through 2029 by using the Revised CSAPR Update's budget-setting methodology, except that the step of that methodology intended to reflect the effects of generation shifting has been eliminated.

The dynamic budget-setting methodology used to determine dynamic state emissions budgets in the year before each control period starting with the 2026 control period is set forth in the revised Group 3 trading program regulations at 40 CFR 97.1010(a). This methodology modifies the Revised CSAPR Update's budget-setting methodology in two ways. First, the baseline EGU inventory and heat input data, but not the emissions rate data, will be updated for each control period using the most recent available reported data in combination with reported data from the four immediately preceding years. For example, in early 2025, using the final data reported for 2020 through 2024, the EPA will update the baseline inventory and heat input data used to determine dynamic state emissions budgets for the 2026 control period.[294] Second, the EPA will not apply an increment or decrement to any state emissions budget for projected generation shifting associated with implementation of the selected control strategies, because any such shifting should already be reflected in the reported heat input data used to update the baseline.

The EPA believes that the revisions to the emissions budget-setting process will substantially improve the ability of the emissions budgets to keep pace with changes in the composition and utilization of the EGU fleet. The dynamic budget-setting methodology will account for the electric power sector's overall trends toward more efficient and cleaner resources, both of which tend to decrease total heat input at affected EGUs, and through 2029 the preset budgets established in the rule will also account for these factors to the extent known. The dynamic budget-setting methodology will also account for other factors that could lead to increased heat input in some states, such as generation shifting from other states or increases in electricity demand caused by rising electrification. The dynamic budget-setting procedure is specified in this final rule's trading program regulations and the computations, which are straightforward, can be performed in a spreadsheet to deliver reliable results. The EPA will provide public notice of the preliminary calculations and the data used by March 1 of the year preceding the control period and will provide an opportunity for submission of any objections to the data and preliminary calculations before finalizing the dynamic budgets for each control period by May 1 of the year before the control period to which those dynamic budgets apply. Thus, for example, sources and other stakeholders will have certainty by May 1, 2025, of the dynamic emissions budgets that will be calculated for the 2026 control period that starts May 1, 2026. Moreover, as of the issuance of this final rule, stakeholders will know the state-level preset emissions budgets for the 2026–2029 control periods, which serve as floors that will only be supplanted by dynamic budgets calculated for those control periods if such a dynamic budget yields a higher amount of tons than the corresponding preset budget established in this action.

It bears emphasis that the annually updated information used in the dynamic budget-setting computations will concern only the composition and utilization of the EGU fleet and not the emissions rate data also used in those computations. The dynamically determined emissions budget computations for all years will reflect only the specific emissions control

[294] As discussed in section VI.B.4 of this document, the state-level data used to determine the overall state-level heat input for computing a state's dynamic budget will be a three-year average (*e.g.,* 2022–2024 state-level data will be used in 2025 to set the 2026 dynamic budgets). The unit-level data used to determine individual units' shares of the state-level heat input in the computations will be the average of the three highest non-zero heat input amounts for the respective units over the most recent five years (*e.g.,* 2020–2024 unit-level data will be used in 2025 to set the 2026 dynamic budgets).

strategies used to determine states' good neighbor obligations as determined in this rulemaking, along with fixed historical emissions rates for units that are not assumed to implement additional control strategies, thereby ensuring that the annual updates will eliminate emissions as determined to be required under the good neighbor provision. The stringency of the emissions budgets will simply reflect the stringency of the emissions control strategies determined in the Step 3 multifactor analysis and will do so more consistently over time than the EPA's previous approach of computing emissions budgets for all future control periods at the time of the rulemaking.

The rule's revisions relating to state emissions budgets and the budget-setting process generally follow the proposal except for two changes we are making in response to comments, specifically: we will use historical data from multiple years rather than a single year in the dynamic budget-setting process, and we are establishing preset emissions budgets for the 2026–2029 control periods such that the dynamic budgets for those control periods will only be imposed where they exceed the corresponding preset budgets finalized in this rule. The rationale for these changes is discussed later in this section as part of the responses to the relevant comments. Details of the final budget-setting methodology and responses to additional comments are discussed further in section VI.B.4 of this document.

The final rule's provisions relating to the determination of state-level variability limits and assurance levels and unit-level allowance allocations are coordinated with the budget-setting methodology. These provisions generally follow the proposal except that the change to the methodology for determining variability limits is implemented starting with the 2023 control period instead of the 2025 control period and the final methodology for determining unit-level allocations of allowances to coal-fired units considers the controlled emissions rate assumptions applicable to the same units in the budget-setting process. Details of these provisions, including the rationales for the changes from proposal, are discussed in sections VI.B.5 and VI.B.9, respectively.

ii. Allowance Bank Recalibration

Besides the levels of the emissions budgets, the second design element of the trading program structure that affects the supply of allowances in each control period, and that consequently also affects the ability of a trading program to maintain the rule's selected control stringency as the EGU fleet evolves over time, is the set of rules concerning the carryover of unused allowances for use in future control periods as banked allowances. As noted previously, trading and banking of allowances in the CSAPR trading programs can serve a variety of purposes: continuously incentivizing sources to reduce their emissions even when they already hold sufficient allowances to cover their expected emissions for a control period, facilitating compliance cost minimization, accommodating necessary operational flexibility, and promoting allowance market liquidity. All of these purposes are advanced by rules that allow sources to trade allowances freely (both with other sources and with non-source entities such as brokers). All of these purposes are also advanced by rules that allow unused allowances to be carried over for possible use in future control periods, thereby preserving a value for the unused allowances. However, while the EPA considers it generally advantageous to place as few restrictions on the trading of allowances as possible,[295] unrestricted banking of allowances has a potentially significant disadvantage offsetting its advantages, namely that it allows what might otherwise be temporary surpluses of allowances in some individual control periods to accumulate into a long-term allowance surplus that reduces allowance prices and weakens the trading program's incentives to control emissions. With weakened incentives, some operators would be more likely to choose not to continuously operate and optimize their emissions controls, imperiling the ongoing achievement of emissions rate performance consistent with the control strategies defined as eliminating significant contribution to nonattainment and interference with maintenance.

As discussed in detail in section VI.B.6 of this rule, the EPA is revising the Group 3 trading program by adding provisions that establish a routine recalibration process for banked allowances that will be carried out in August 2024 and each subsequent August, after the compliance deadline for the control period in the previous year. In each recalibration, the EPA will reset the total quantity of banked allowances for the Group 3 trading program (''Group 3 allowances'') held in all Allowance Management System accounts to a level computed as a target percentage of the sum of the state emissions budgets for the current control period. The target percentage will be 21 percent for the 2024–2029 control periods and 10.5 percent for control periods in 2030 and later years. The recalibration procedure entails identifying the ratio of the target bank amount to the total quantity of banked allowances held in all accounts before the recalibration and then, if the ratio is less than 1.0, multiplying the quantity of banked allowances held in each account by the ratio to identify the appropriate recalibrated amount for the account (rounded to the nearest allowance), and deducting any allowances in the account exceeding the recalibrated amount.

As noted previously, recalibration of the bank for each control period will be carried out in August of that control period. This timing will accommodate the process of deducting allowances for compliance for the previous control period, which cannot be completed before sources' June 1 compliance deadline for the previous control period, and will then provide approximately two additional months for sources to engage in any desired allowance transactions before recalibration occurs. However, data that can be used to estimate the bank recalibration ratio for each control period will be available shortly after the end of the previous control period, and the EPA will use these data to make information on the estimated bank recalibration ratio for each control period publicly available no later than March 1 of the year of that control period, thereby facilitating the ability of affected EGUs to anticipate their ultimate holdings of recalibrated banked allowances to inform their compliance planning for that control season. Affected EGUs will also have several months following the completed bank recalibration in August to transact allowances with other parties as needed

[295] The advantages of trading programs discussed earlier in this section—providing continuous emissions reduction incentives, facilitating compliance cost minimization, and supporting operational flexibility—depend on the existence of a marketplace for purchasing and selling allowances. Broader marketplaces generally provide greater market liquidity and therefore make trading programs better at providing these advantages. The EPA recognizes that unrestricted use of *net* purchased allowances—meaning quantities of purchased allowances that exceed the quantities of allowances sold—by a source or group of sources as an alternative to making emissions reductions can interfere with the achievement of the desired environmental outcome. Therefore, section VI.B.1.c of this document discusses the enhancements to the Group 3 trading program that the EPA is making in this rulemaking to reduce reliance on net purchased allowances by incentivizing or requiring better environmental performance at individual EGUs. However, the concern arises from the *use of an excessive quantity* of net purchased allowances for a particular purpose, not from the existence of a *marketplace* where allowances may be freely bought and sold.

before the allowance transfer deadline of June 1 of the following year.

The EPA believes this revision to the Group 3 trading program's banking provisions establishing an annual bank recalibration process will complement the revisions to the budget-setting process by preventing any surplus of allowances created in one control period from diminishing the intended stringency and resulting emissions reductions of the emissions budgets for subsequent control periods.

The calibration procedure will not erase the value of unused allowances for the holder, because the larger the quantity of banked allowances that is held in a given account before each recalibration, the larger the quantity of banked allowances that will be left in the account after the recalibration for possible sale or use in meeting future compliance requirements. Because the banked allowances will always have value, the opportunity to bank allowances will continue to advance the purposes served by otherwise unrestricted banking as described previously. Opportunities to bank unused allowances can serve all these same purposes whether a banked allowance is of partial value (if the bank needs recalibrating to its target level) or is of full value compared to a newly issued allowance for the next control period.

The final rule's provisions relating to bank recalibration generally follow the proposal except that, in response to comments, the target percentage used to determine the recalibrated bank levels for the 2024–2029 control periods is being set at 21 percent instead of 10.5 percent. The rationale for this change is discussed later in this section as part of the responses to the relevant comments. Details of the bank recalibration provisions are discussed further in section VI.B.6 of this rule.

c. Enhancements To Improve Emissions Performance at Individual Units

The second set of concerns about the structure of the current CSAPR trading programs relates to the general absence of source- or unit-specific emissions reduction requirements. Without such requirements, the programs affect individual sources' emissions performance only to the extent that the incentives created by allowance prices are high enough relative to the costs of the sources' various emissions control opportunities. In circumstances where the incentives to control emissions are insufficient, some individual sources even idle existing emissions controls. Emissions from these individual sources can contribute to increased pollution concentrations downwind on the particular days that matter for downwind exceedances of the relevant air quality standard.

This EPA intends that the trading program enhancements described in section VI.B.1.b of this rule will improve the Group 3 trading program's ability to sustain emissions control incentives over time such that needed emissions performance will be achieved by all participating units without the need for additional requirements to be imposed at the level of individual units. However, because obtaining needed emissions performance at individual units is also important to the elimination of significant contribution in keeping with the EPA's Step 3 determinations, the EPA is supplementing the previously discussed enhancements with two other new sets of provisions that will apply to certain individual units within the larger context of the Group 3 trading program. The allowance price will continue to be the most important driver of good environmental performance for most units, but the proposed unit-level requirements will be important supplemental drivers of performance and will offer additional assurance that significant contribution is eliminated on a daily basis during the ozone season by more continuous operation of existing pollution controls.

i. Unit-Specific Backstop Daily Emissions Rates

The first of the trading program enhancements intended to improve emissions performance at the level of individual units is the addition of backstop daily NO_X emissions rate provisions that will apply to large coal-fired EGUs, defined for this purpose as units serving electricity generators with nameplate capacities equal to or greater than 100 MW and combusting any coal during the control period in question. Starting with the 2024 control period, a 3-for-1 allowance surrender ratio (instead of the usual 1-for-1 surrender ratio) will apply to emissions during the ozone season from any large coal-fired EGU with existing SCR controls exceeding by more than 50 tons a daily average NO_X emissions rate of 0.14 lb/mmBtu. The additional allowance surrender requirement will be integrated into the trading program as a new component in the calculation of each unit's primary emissions limitation, such that the additional allowances will have to be surrendered by the same compliance deadline of June 1 after each control period. The amount of additional allowances to be surrendered will be determined by computing, for each day of the control period, any excess of the unit's reported emissions (in pounds) over the emissions that would have resulted from combusting that day's actual heat input at an average daily emissions rate of 0.14 lb/mmBtu, summing the daily amounts, converting from pounds to tons, computing the amount of any excess over 50 tons, and multiplying by two. Starting with the second control period in which newly installed SCR controls are operational, but not later than the 2030 control period, the 3-for-1 surrender ratio will apply in the same way to all large coal-fired EGUs except circulating fluidized bed units, consistent with EPA's determination that a control stringency reflecting installation and operation of SCR controls on all such large coal-fired EGUs is appropriate to address states' good neighbor obligations with respect to the 2015 ozone NAAQS.

In prior rules addressing interstate transport of air pollution, stakeholders have noted that while seasonal cap-and-trade programs are effective at lowering ozone and ozone-forming precursors across the ozone season, attainment of the standard is measured on key days and therefore it is necessary to ensure that the rule requires emissions reductions not just seasonally, but also on those key days.[296] They have noted that while the trading programs established under the NO_X SIP Call, CAIR, and CSAPR have all been successful in ensuring seasonal reductions, states must remain below daily peak levels, not just seasonal levels, to reach attainment. These downwind stakeholder communities have suggested that operating pollution controls on the highest ozone days (and immediately preceding days) during the ozone season is of critical importance. The EPA has analyzed hourly emissions data reported in prior cap-and-trade programs and has identified instances of sources that did not operate SCR controls for substantial portions of recent ozone seasons. These instances are discussed in section V.B.1.a of this document and in the EGU NO_X Mitigation Strategies Final Rule TSD in the docket. While the EPA has in prior ozone transport actions not found sufficient evidence of emissions control idling or non-optimization to take the step of building in enhancements to the trading program to ensure unit-level control operation, our review of subsequent-year data for prior programs suggests that the non-optimization

[296] *E.g.,* comments of Maryland Department of the Environment on the proposed Revised CSAPR Update at 3, EPA–HQ–OAR–2020–0272–0094.

behavior increases in the latter years of a program. Applied to this context (*e.g.,* a rule providing a full remedy to interstate transport for the more protective 2015 ozone NAAQS and an extended period of expected persistence of receptors), this data suggests this deterioration in performance could become prevalent and problematic in future years if not addressed. Rather than allow for the potential of continued deterioration in the environmental performance of our trading programs, the EPA finds the evidence of declining SCR performance in later years of trading programs sufficient to justify prophylactic measures in this rule to ensure the emissions control strategy selected at Step 3 is indeed implemented at Step 4. Thus, particularly in the context of the more protective 2015 ozone NAAQS combined with the full remedy nature of this action and the extended timeframe for which upwind contribution to downwind nonattainment is projected to persist, the EPA agrees with these stakeholders that the set of measures promulgated in this rulemaking to implement the control stringency levels found necessary to address states' good neighbor obligations should include measures designed to more effectively ensure that individual units operate their emissions controls routinely throughout the ozone season, thereby also ensuring that the controls are planned to be in operation on the particular days that turn out to be most critical for ozone formation and for attainment of the NAAQS. Routine operation of emissions controls will also provide relief to overburdened communities downwind of any units that might otherwise have chosen not to operate their controls. In the Ozone Transport Policy Analysis Final Rule TSD, the EPA conducted a screening analysis that found nearly all of the EGUs included in this analysis are located within a 24-hour transport distance of many areas with potential EJ concerns. Thus, the EPA is adopting backstop daily rate limits at the individual unit level because it is appropriate and justified in the context of eliminating significant contribution under CAA section 110(a)(2)(D)(i)(I). While the former justification is sufficient to finalize this enhancement to the trading program, we also anticipate that this measure will deliver public health and environmental benefits to overburdened communities (as well as the rest of the population).[297]

We considered whether, as some commenters suggested, it would be appropriate to simply implement unit-specific daily emissions limitation at all of the large, coal-fired EGUs, and forego an emissions trading approach altogether. While this is within the EPA's statutory authority, *see* CAA section 110(a)(2)(A) and 302(y), and merits careful consideration, we are declining to do so in this action but intend to closely monitor EGU emissions performance in response to the trading program finalized here. The purpose of establishing a backstop daily NO_X emissions rate and implementing it through additional allowance surrender requirements instead of as an enforceable emissions limitation is to incentivize improved emissions performance at the individual unit level while continuing to preserve, to the extent possible, the advantages that the flexibility of a trading program brings to the electric power sector. As discussed in section VI.B.7 of this document, under the EPA's historical trading programs without the enhancements made in this rulemaking, some individual coal-fired units with SCR controls have chosen to operate the controls at lower removal efficiencies than in past ozone seasons or even to idle the controls for entire ozone seasons. In addition, some SCR-equipped units have chosen to routinely cycle their emissions controls off at lower load levels, such as while operating overnight, instead of operating the controls, upgrading the units to enable the controls to be operated under those conditions, or not operating the units under those conditions. Collectively, this non-optimization of existing controls has a detrimental impact on problematic receptors. Table V.D.1–1 shows the expected air quality benefit from control optimization (totaling nearly 1.6 ppb change across all receptors).[298]

The EPA has identified sources of interstate ozone pollution such as the New Madrid and Conemaugh plants (in Missouri and Pennsylvania, respectively) whose SCR controls were not operating for substantial portions of recent ozone seasons. The data included in Appendix G of the Ozone Transport Policy Analysis Final Rule TSD, available in the docket for this rulemaking, demonstrate that these units have operated their SCRs better and more consistently during years with higher NO_X allowance prices. Downwind stakeholders have noted that some of the higher emissions rates (specifically in the case of Conemaugh Unit 2 in 2019) have occurred on the day of and the preceding day of an ozone exceedance in bordering states.[299]

The EPA believes that the design of the daily emissions rate provisions will be effective in addressing these types of high-emitting behavior by significantly raising the cost of planned operator decisions that substantially compromise environmental performance. At the same time, the provision will not unduly penalize an occasional unplanned exceedance, because the amount of additional allowances that would have to be surrendered to address a single day's exceedance would be much smaller than the amount that would have to be surrendered to address planned poor performance sustained over longer time periods. Moreover, the EPA believes that the inclusion of a 50-ton threshold before the increased surrender requirements would apply is sufficient to address virtually all instances where a unit's emissions would exceed the 0.14 lb/mmBtu daily rate because of unavoidable startup or shutdown conditions during which SCR equipment cannot be operated, thereby ensuring that the provision will not penalize units for emissions that are beyond their reasonable control.

The EPA is applying the daily emissions rate provisions to large coal-fired EGUs, and not to other types of units, for reasons that are consistent with EPA's determinations regarding the appropriate control stringency for EGUs to address states' good neighbor obligations with respect to the 2015 ozone NAAQS. Installation and operation of SCR controls is well-established as a common practice for the best control of NO_X emissions from coal-fired EGUs, as evidenced by the fact that the technology is already installed on more than 60 percent of the sector's total coal-fired capacity and installed on nearly 100 percent of the coal fired boilers in the top quartile of emissions rate performance. In the context of addressing good neighbor obligations with respect to the 2015 ozone NAAQS, the EPA is determining that a control stringency reflecting universal installation and operation of SCR technology at large coal-fired EGUs (other than circulating fluidized bed units) is appropriate at Step 3. Finally, where SCR controls are installed on such units, optimized operation of those controls is an extremely cost-effective method of achieving NO_X emissions

[297] Nonetheless, the environmental justice exposure analysis indicates that preexisting disparities among demographic groups are likely to persist even under this final rule. *See* section VII of this document.

[298] As illustrated in the table and underlying data, a small portion of this ppb impact is attributable to combustion control upgrade potential.

[299] EPA–HQ–OAR–2020–0272–0094.

reductions. The EPA believes these considerations support establishment of the daily emissions rate provisions on a universal basis for large coal-fired EGUs, with near-term application of the provisions for units that already have the controls installed and deferred application for other units, as discussed later.

With regard to gas-fired steam EGUs, SCR controls are nowhere near as prevalent, and while the EPA is including some SCR controls at gas-fired steam units in the selected control stringency at Step 3, the EPA is not including universal SCR controls at gas-fired steam units. Because the EPA is not determining that universal installation and operation of SCR controls at gas-fired steam EGUs is part of the selected control stringency, in order not to constrain the power sector's flexibility to choose which particular gas-fired steam EGUs are the preferred candidates for achieving the required emissions reductions, the EPA is not applying the daily emissions rate provisions to large gas-fired steam EGUs. Focusing the backstop daily emissions rates on coal-fired units is also consistent with stakeholder input which has emphasized the need for short-term rate limits at coal units given their relatively higher emissions rates.

The EPA developed the level of the daily average NO_X emissions rate—0.14 lb/mmBtu—through analysis of historical data, as described in section VI.B.7 of this document. A rate of 0.14 lb/mmBtu represents the daily average NO_X emissions rate that has been demonstrated to be achievable on approximately 95 percent of days covering more than 99 percent of total ozone-season NO_X emissions by coal-fired units with SCR controls that are achieving a seasonal NO_X average emissions rate of 0.08 lb/mmBtu (or less), which is the seasonal NO_X emissions rate that the EPA has determined is indicative of optimized SCR performance by units with existing SCR controls.

As noted previously, the daily average emissions rate provisions will apply beginning in the 2024 control period for large coal-fired units with installed SCR controls, one control period later than optimization of those controls will be reflected in the state emissions budgets under this rule. For these units, not applying the daily average rate provisions until 2024 serves three purposes. First, it provides all the units with a preparatory interval to focus attention on improving not only the average performance of their SCR controls but also the day-to-day consistency of performance before they will be held to increased allowance-surrender consequences for exceeding the daily rate. Second, it provides the subset of units that exhaust to common stacks with other units that currently lack SCR controls an opportunity to exercise the option to install and certify any additional monitoring systems needed to monitor the individual units' NO_X emissions rates separately; otherwise, the daily emissions rate provisions will apply to the SCR-equipped units based on the combined NO_X emissions rates measured in the common stacks. Third, it provides all units sufficient time to update the data handling software in their existing monitoring systems as needed to compute and report the additional hourly and daily data values needed for implementation of the provisions.[300]

With respect to the units without existing SCR controls, the daily average emissions rate provisions will apply starting with the second control period in which newly installed SCR controls are operational at the unit, but not later than the 2030 control period. This implementation timing represents a change from the proposal, under which the daily average emissions rate provisions would have applied to units without existing SCR starting in the 2027 control period. Commenters noted that for many units without SCR, replacement of the unit within a few years, and shifting of some generation to cleaner units in the interim, would be a more economic compliance strategy than installation of new SCR controls. The commenters further noted that implementation of the daily average emissions rate for these units starting in 2027 would strongly disadvantage such an alternative strategy if the capacity replacement and any associated transmission improvements could not be implemented by 2027. In light of these comments, the EPA has determined that as long as the emissions budgets determined in this rule to eliminate significant contribution are still being implemented as expeditiously as practicable—which in this instance the EPA has determined requires phasing in the required emissions reductions by 2027—it is reasonable to defer implementation of the daily average emissions rate provisions to 2030 for units without SCR to allow temporarily greater flexibility to pursue compliance strategies other than installation of new controls. This lag is permissible consistent with the obligation to eliminate significant contribution for reasons that are further discussed in response to comments in section VI.B.1.d of this document. However, for any units that choose a compliance strategy of installing new SCR controls before 2030, the daily average emissions rate provisions would apply in the second control period of operation. Specification of the second control period rather than the first control period provides the unit operators with an opportunity to gain operational experience with the new equipment before the units will be held to increased allowance-surrender consequences for exceeding the daily rate.

The unit-specific daily emissions rate provisions are being finalized as proposed except for two changes noted in the previous summary: the exclusion from extra allowance surrender requirements of a unit's first 50 tons of emissions in a control period exceeding the backstop daily rate, and the revision of the starting date for implementation of the requirement for units without existing SCR controls to 2030 or the second control period of SCR operation, if earlier. The rationale for these changes is further discussed in the responses to comments later in this section. Additional details of the unit-specific daily emissions rate provisions are discussed in section VI.B.7 of this document.

ii. Unit-Specific Emissions Limitations Contingent on Assurance Level Exceedances

The second of the trading program enhancements intended to improve emissions performance at the level of individual units is the addition of unit-specific secondary emissions limitations for units with post-combustion controls starting with the 2024 control period. The secondary emissions limitations will be determined on a unit-specific basis according to each unit's individual performance but will apply to a given unit only under the circumstance where a state's assurance level for a control period has been exceeded, 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 the unit operated during at least 10 percent of the hours in the control period. Where these conditions for application of a secondary emissions limitation to a given unit for a given control period are met, the unit's secondary emissions limitation consists of a prohibition on NO_X emissions during the control

[300] For further discussion of emissions monitoring and reporting requirements under the rule, including the options available to plants where SCR-equipped and non-SCR-equipped coal-fired units exhaust to common stacks, see section VI.B.10 of this document.

period that exceed by more than 50 tons the NO_X 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 NO_X trading program during which the unit operated for at least 10 percent of the hours.

The secondary emissions limitation is in addition to, not in lieu of, the primary emissions limitation applicable to each source, which continues to take the form of a requirement to surrender a quantity of allowances based on the source's emissions, and also in addition to the existing assurance provisions, which similarly continue to take the form of a requirement for the owners and operators of some sources to surrender additional allowances when a state's assurance level is exceeded. In contrast to these other requirements, the unit-specific secondary emissions limitation takes the form of a prohibition on emissions over a specified level, such that any emissions by a unit exceeding its secondary emissions limitation would be subject to potential administrative or judicial action and subject to penalties and other forms of relief under the CAA's enforcement authorities. The reason for establishing this form of limitation is that experience under the existing CSAPR trading programs has shown that, in some circumstances, the existing assurance provisions have been insufficient to prevent exceedances of a state's assurance level for a control period even when the likelihood of an exceedance has been foreseeable and the exceedance could have been readily avoided if certain units had operated with emissions rates closer to the lower emissions rates achieved in past control periods. The assurance levels exist to ensure that emissions from each state that contribute significantly to nonattainment or interfere with maintenance of a NAAQS in another state are prohibited. *North Carolina* v. *EPA,* 531 F.3d 896, 906–08 (D.C. Cir. 2008). The EPA's programs to eliminate significant contribution must therefore achieve this prohibition, and the evidence of foreseeable and avoidable exceedances of the assurance levels demonstrates that EPA's existing approach has not been sufficient to accomplish this.

The purpose of including assurance levels higher than the state emissions budgets in the CSAPR trading programs is to provide flexibility to accommodate operational variability attributable to factors that are largely outside of an individual owner's or operator's control, not to allow owners and operators to plan to emit at emissions rates that could be anticipated to cause a state's total emissions to exceed the state's emissions budget or assurance level. Conduct leading to a foreseeable, readily avoidable exceedance of a state's assurance level cannot be reconciled with the statutory mandate of the CAA's good neighbor provision that emissions "within the state" significantly contributing to nonattainment or interfering with maintenance of a NAAQS in another state must be prohibited. Because the current CSAPR regulations do not expressly prohibit such conduct and have proven insufficient to deter it in some circumstances, the EPA is correcting the regulatory deficiency in the Group 3 trading program by adding secondary emissions limitations that cannot be complied with through the use of allowances.

The EPA notes that although the purpose of the secondary emissions limitations is to strengthen the assurance provisions, which apply on a statewide, seasonal basis, the unit-specific structure of the new limitations will strengthen the incentives for individual units with post-combustion controls to maintain their emissions performance at levels consistent with their previously demonstrated capabilities. The new limitations will strengthen the incentives to operate and optimize the controls continuously, which can be expected to reduce some individual units' emissions rates throughout the ozone season, including on the days that turn out to be most critical for downwind ozone levels. Better emissions performance on average across the ozone season by individual units likely will also help address impacts of pollution on overburdened communities downwind from some such units. *See* Ozone Transport Policy Analysis Final Rule TSD, Section E.

The unit-specific secondary emissions limitations are being finalized as proposed except that the limitations will apply only to units with post-combustion controls. The rationale for this change, and additional details regarding the provisions, are discussed in section VI.B.8 of this document.

d. Responses to General Comments on the Revisions to the Group 3 Trading Program

This section summarizes and provides the EPA's responses to overarching comments received on the EPA's proposal to implement the emissions reductions required from EGUs under this rule through expansion and enhancement of the Group 3 trading program originally established in the Revised CSAPR Update, particularly comments on electric system reliability. Responses to comments about individual aspects of the enhanced trading program are addressed in the respective subsections of this section in which those aspects are discussed. Responses to comments concerning alleged overcontrol and the EPA's legal authority are in sections V.D. and III. Comments not addressed in this document are addressed in the separate *RTC* document available in the docket for this action.

Comment: Some commenters, including EGU owners, states, and several RTOs, expressed concern that the requirements for EGUs as formulated in the proposal could lead to a degradation in the reliability of the electric system. As background, some of these commenters noted that the power sector is currently undergoing rapid change, with older and less economic fossil-fuel-fired steam generating units retiring while the majority of the new capacity being added consists of wind and solar capacity. They noted that fossil-fuel-fired generating capacity provides reliability benefits not necessarily provided by other types of generating capacity, including not only the ability to generate electricity in the absence of wind or sunlight, but also inertia, ramping capability, voltage support, and frequency response. Commenters stated that past EGU retirements and the pace of change in the generating capacity mix have already been stressing the electric system in some regions, and that the forecasted risk of events where the electric system would be unable to fully meet load is rising.

For purposes of their comments, these commenters generally assumed that the rule would lead to additional retirements of fossil-fuel-fired generating capacity beyond the retirements that EGU owners have already planned and announced. Some of the commenters also suggested that remaining fossil-fuel-fired generators would be unwilling to operate when needed because allowances might be unavailable for purchase or too costly. In the context of an already-stressed electric system, the commenters predicted that these assumed consequences of the rule would threaten resource adequacy and result in degraded electric reliability. To support their assumptions concerning additional retirements, some of the commenters pointed to projections of incremental generating capacity retirements included in the results of modeling performed by the EPA to analyze the costs and benefits of the proposed rule. Some commenters indicated that they expected EGU owners to be interested in retiring and replacing uncontrolled units as of the date of implementation of the backstop daily rate requirement on uncontrolled units, and expressed concern that the proposal to implement that requirement as of the 2027 control period did not allow sufficient time for planning and implementation of all the necessary generation and transmission investments to make this a viable compliance strategy; for these commenters, 2027 and the immediately following years were the period of greatest concern. Some commenters appear simply to have assumed that owners of units not already equipped with SCR controls would choose to retire the units as of the ozone season in which the units would otherwise become subject to the backstop daily emissions rate provisions, regardless of whether replacement investments had been completed.

Some of the commenters raising concerns about electric system reliability suggested potential modifications to the proposed rule that the commenters believed could help address their concerns. The suggestions included various mechanisms for suspending some or all of the trading program's requirements for certain EGUs at times when an RTO or other entity responsible for overseeing a region of the interconnected electrical grid determines that generation from those EGUs is needed and the EGUs might not otherwise agree to operate. Other suggestions focused on ways of providing EGUs with greater confidence that allowances would be available to cover their incremental emissions during particular events. A number of commenters used the term ''reliability safety valve,'' in some cases with reference to the types of suggestions just mentioned and in other cases without details. Some commenters pointed to the ''safety valve'' provision included in the Group 2 trading program regulations under the Revised CSAPR Update. Another commenter pointed to provisions for a ''reliability safety valve'' included in the Clean Power Plan (80 FR 64662, Oct. 23, 2015).

In addition to offering critiques and recommendations concerning the proposed rule's contents, some commenters claimed that the EPA had failed to conduct sufficient analysis of the potential implications of the proposed rule on electrical system reliability. These commenters called on the EPA to consult with RTOs and other entities with responsibilities relating to electric system reliability and to perform additional analysis. Some commenters advocated for renewed consultations and analysis before each planned adjustment to emissions budgets under the dynamic budget-setting process. Commenters cited the consultation processes followed during implementation of other EPA rules, such as the Mercury and Air Toxics Standards (MATS) (77 FR 9304, Feb. 16, 2012).

Response: The EPA disagrees with the comments asserting that this rule would threaten resource adequacy or otherwise degrade electric system reliability. The emissions reduction requirements for EGUs under this rule are being implemented through the mechanism of an allowance trading program. Under the trading program, no EGU is required to cease operation. The core trading program requirements for a participating EGU are to monitor and report the unit's NO_X emissions for each ozone season period and to surrender a quantity of allowances after the end of the ozone season based on the reported emissions. To address states' obligations under the good neighbor provision, some units of course will have to take some type of action to reduce emissions, the actions taken to reduce emissions will generally have costs, and some EGU owners will conclude that, all else being equal, retiring a particular EGU and replacing it with cleaner generating capacity is likely to be a more economic option from the perspective of the unit's customers and/or owners than making substantial investments in new emissions controls at the unit. However, the EPA also understands that before implementing such a retirement decision, the unit's owner will follow the processes put in place by the relevant RTO, balancing authority, or state regulator to protect electric system reliability. These processes typically include analysis of the potential impacts of the proposed EGU retirement on electrical system reliability, identification of options for mitigating any identified adverse impacts, and, in some cases, temporary provision of additional revenues to support the EGU's continued operation until longer-term mitigation measures can be put in place. No commenter stated that this rule would somehow authorize any EGU owner to unilaterally retire a unit without following these processes, yet some comments nevertheless assume that is how multiple EGU owners would proceed, in violation of their obligations to RTOs, balancing authorities, or state regulators relating to the provision of reliable electric service. Assumptions of this nature are simply not reasonable. Like many commenters, the EPA does expect that retirement will be viewed as a more economic compliance strategy for some EGUs than installing new controls, but the Agency also expects that any resulting unit retirements will be carried out through an orderly process in which RTOs, balancing authorities, and state regulators use their powers to ensure that electric system reliability is protected. The trading program inherently provides ample flexibility to allow such an orderly transition to take place. In addition, as discussed later in this section, the EPA has adopted several changes in the final rule to increase flexibility specifically for the early years of the trading program for which commenters have indicated the greatest concerns about electric system reliability.

As an initial matter, the EPA notes two fundamental aspects of this rulemaking which together provide a strong foundation for the Agency's conclusion that the emissions reductions required from EGUs can be achieved with no adverse impacts on electric system reliability. First, there is ample evidence indicating that the required emissions reductions are feasible. As discussed in section V of this document, the magnitude and timing of the EGU emissions reductions required by this action reflect application of technologies that are already in widespread use, on schedules that are supported by industry experience. Second, the required emissions reductions are being implemented through the mechanism of a trading program. The enhanced trading program under this rule, like the trading programs established by the EPA under prior rules, provides EGU owners with opportunities to substitute emissions reductions from sources where achieving reductions is cheaper and easier for emissions reductions from other sources where achieving reductions is more costly or difficult. In general, an EGU owner has options to operate the emissions controls identified by the EPA for that type of unit (including installation or upgrade of controls where necessary), operate other types of emissions controls, or adapt the unit's levels of operation to produce less generation if the unit is a higher-emitting EGU or more generation if the unit is a lower-emitting EGU. The backstop daily emissions rate provisions in this rule reduce the degree of available flexibility relative to the degree of flexibility in the Agency's previous trading programs under CAIR and CSAPR but by no means eliminate it. Moreover, even the backstop rate provisions are structured as requirements to surrender additional allowances rather than as hard limits, providing a further element of flexibility No EGU is required to retire or is prohibited from operating at any time under this rule. EGUs only need to surrender of the appropriate quantities of allowances after the end of the control period.[301]

Further, in the large number of comments submitted in this rulemaking that assert concerns over electric system reliability, no commenter has cited a single instance where implementation of an EPA trading program has actually caused an adverse reliability impact. Indeed, similar claims made in the context of the EPA's prior trading program rulemakings have shown a considerable gap between rhetoric and reality. For example, in the litigation over the industry's multiple motions to stay implementation of CSAPR, claims were made that allowing the rule to go into effect would compromise reliability. Yet in the 2012 ozone season starting just over 4 months after the rule was stayed, EGUs covered by CSAPR collectively emitted below the overall program budgets that the rule would have imposed in that year if the rule had been allowed to take effect, with most individual states emitting below their respective state budgets despite CSAPR not being in effect.[302] Similarly, in the litigation over the 2015 Clean Power Plan, assertions that the rule would threaten electric system reliability were made by some utilities or their representatives, yet even though the Supreme Court stayed the rule in 2016, the industry achieved the rule's emissions reduction targets without the rule ever going into effect. *See West Virginia* v. *EPA,* 142 S. Ct. 2587, 2638 (2022) (Kagan, J., dissenting) ("[T]he industry didn't fall short of the [Clean Power] Plan's goal; rather, the industry exceeded that target, all on its own. . . . At the time of the repeal . . . 'there [was] likely to be no difference between a world where the [Clean Power Plan was] implemented and one where it [was] not.' ") (quoting 84 FR 32561). The claims that these rules would have had adverse reliability impacts were proved to be groundless.

Notwithstanding the long experience confirming the ability of the EPA's trading programs to obtain emissions reductions from EGUs without impairing the sector's ability to provide reliable electric service, the Agency of course does not rely here solely on its experience, but has carefully reviewed the comments on this topic for any information that might indicate the appropriateness of modifications to the enhanced trading program as proposed. In recognition of the important role that RTOs play in ensuring electric system reliability, and consistent with the requests of some commenters, the EPA has engaged in outreach to the RTOs that commented on the proposal to better understand their comments specifically and the reliability-related comments of other commenters more generally.[303] Through these meetings, the central reliability-related concern was identified as one of timing. In order for retirement to be a viable compliance strategy for a unit that cannot be entirely spared until replacement investments in generation or transmission are completed, it must be possible for the unit to operate at critical times for a transition period. Like other stakeholders, the RTOs perceived implementation of the backstop daily emissions rate provisions on uncontrolled units as materially strengthening incentives for such units to either install controls or retire. The RTOs were concerned that the option for a coal-fired unit without SCR controls to maintain limited operation while surrendering allowances at a 3-for-1 ratio for all emissions exceeding the backstop daily rate was one that EGU owners would be reluctant to pursue. Accordingly, the RTOs expected considerable interest from EGU owners in retiring and replacing uncontrolled units as of the date of implementation of the backstop daily rate requirement on uncontrolled units, and they were concerned that the proposal to implement that requirement as of the 2027 control period did not allow sufficient time for planning and implementation of all the necessary generation and transmission investments to make this a viable compliance strategy. The RTOs described their concerns as greatest through approximately the 2029 control period.

The RTOs also described a concern about potentially illiquid allowance markets. They believed it was possible that some EGUs might claim an inability to operate at particular times when needed unless they had confidence that they would be able obtain additional allowances. The RTOs were particularly concerned that introduction of dynamic budgeting as proposed would create uncertainty for some EGUs regarding the quantities of allowances they would have available for use, particularly given the potentially large year-to-year swings if budgets were based on historical data from a single year. Some of the RTOs suggested potential solutions for these issues, principally in the form of auctions or RTO-administered allocations of allowances from pools of supplemental allowances, with access to the supplemental allowances triggered by certain indications of temporary stress on the electric system.

In the final rule, the EPA is adopting several changes from the proposal to help address the reliability-related concerns that were identified in comments and brought into greater focus by the consultations with the RTOs. The first change adopted in response to these comments is that application of the backstop daily NO_X emissions rate to units without existing SCR controls is being deferred until the 2030 control period, or the second control period in which a unit operates new SCR controls, if earlier. The purpose of this change is to address the concerns that application of the backstop daily NO_X emissions rate to EGUs without existing SCR starting in 2027 would provide insufficient time for planning and investments needed to facilitate unit retirement as a compliance pathway, which some commenters noted they prefer or have already planned. In particular, where an EGU owner would prefer to retire and replace an uncontrolled EGU rather than to install new controls, and in recognition that reliability-related needs may require some degree of operation from such units in the period before the investments needed to replace the unit can be completed, deferral of the backstop daily emissions rate provisions ensures that the necessary generation can be provided without being made subject to a 3-for-1 allowance surrender ratio that might render that compliance strategy uneconomic compared to the faster but less environmentally beneficial compliance strategy of installing new controls. The EPA has considered the statutory mandate that states' good neighbor obligations—

[301] The EPA has prepared a resource adequacy assessment of the projected impacts of the final rule showing that the projected impacts of the final rule on power system operations, under conditions preserving resource adequacy, are modest and manageable. See *Resource Adequacy and Reliability Analysis Final Rule TSD,* available in the docket.

[302] For a state-by-state comparison, see Appendix G of the Ozone Transport Policy Analysis Final Rule TSD.

[303] The EPA also met with non-RTO balancing authorities that submitted comments. Memoranda identifying the dates, attendees, and topics of discussion of these meetings with RTOs and non-RTO balancing authorities are available in the docket.

including this action's requirement for large coal-fired EGUs to make emissions reductions commensurate with good SCR operation—be addressed as expeditiously as practicable. The EPA has also considered the fact that in this rule, the backstop daily emissions rate serves as a supplement to the broader requirement for emissions reductions commensurate with application of several control technologies at several types of EGUs, encompassing the extent of emissions reductions that would be incentivized by the backstop emissions rate requirement. The EPA views the backstop daily emissions rate as part of the solution to eliminating significant contribution in that it strongly incentivizes emissions-control operation throughout each day of the ozone season. *See* sections III.B.1.d, VI.B.1.b, VI.B.1.c.i. For that reason, in general we are finalizing the daily backstop emissions rate for units that have SCR installed or that install it in the future. It is only as an exception to that general rule that we defer the backstop daily emissions rate given the transition period and reliability concerns identified by commenters. The EPA finds that in this circumstance, as long as state emissions budgets continue to reflect the required degree of emissions reductions, deferral of the backstop rate requirement for uncontrolled units for a transition period can be justified on the basis of the greater long-term environmental benefits obtained through facilitating the replacement of these affected EGUs with cleaner sources of generation. Beginning in the 2030 ozone season, all coal-fired EGUs identified for SCR retrofit potential in this action will be subject to the backstop daily emissions rate. Any such units that remain in operation in that year can and should meet the backstop daily emissions rate or be subject to the heightened allowance surrender ratio.

The second change from the proposal adopted in response to the reliability-related comments is that the target percentage of the states' emissions budgets used to recalibrate the target bank level will be set at the proposed 10.5 percent starting in the 2030 control period, and for the control periods from 2024 through 2029, a target percentage of 21 percent will be used instead. The adoption of the higher target percentage for use through the 2029 control period is intended to promote greater allowance market liquidity during a period of relatively rapid fleet transition about which commenters expressed more focused reliability-related needs. As discussed later in this section, the EPA expects the introduction of the bank recalibration process in 2024 generally to boost market liquidity (by discouraging allowance hoarding) and also considers the target percentage of 10.5 percent set forth in the proposal well supported. Nevertheless, the Agency agrees with suggestions by commenters that, at least in the early years of the enhanced trading program, a larger bank would provide further liquidity and would give program participants greater confidence that allowances would be available for purchase when needed. Greater confidence by sources would help address RTOs' concern about the possibility that some sources could be reluctant to operate if they were unsure of their ability to procure allowances to cover their emissions. In finding that this modification from proposal is appropriate, the EPA has considered the fact that use of a higher target percentage will not result in the creation of any additional allowances in any control period, because under the recalibration provisions, when the total quantity of allowances banked from the previous control period is less than the bank target level, the consequence is not that additional allowances are created to raise the bank to the target level, but simply that no bank adjustment is carried out. We also note that while including an annual bank recalibration of any percentage is an enhancement in the trading program from prior trading programs under the good neighbor provision established in the CAIR, CSAPR, CSAPR Update, and Revised CSAPR Update rulemakings, it is not unprecedented; the trading program established under the NO_X SIP Call included ''progressive flow control'' provisions that were designed differently from the bank recalibration provisions in this rule but had the same purpose and general effect.

The third change from the proposal adopted in response to the reliability-related comments is that the EPA is determining preset state emissions budgets not only for the control periods in 2023 and 2024 as proposed, but also for the control periods in 2025 through 2029. Finalizing preset state emissions budgets through 2029 will establish predictable amounts for the minimum quantities of allowances available during the period when commenters have expressed concern that the reliability-related need for such predictability is greatest. Moreover, the EPA will also determine state emissions budgets using the final dynamic budget-setting methodology for the control periods in 2026 through 2029, and for each state and control period, the dynamic budget to be published in the future will only supplant the preset budget finalized in this rule for a control period in which that dynamic budget is higher than the corresponding preset budget. The reason for using dynamic budgets when they are higher than the corresponding preset budgets is that the EPA recognizes that evolution of the EGU fleet will not follow the exact path projected at the time of the rulemaking, and that by not accounting for certain events, the preset methodology could result in issuance of smaller quantities of allowances than the EPA would find consistent with the quantities of emissions from a well-controlled EGU fleet using the dynamic budget-setting methodology. Events that could cause preset budgets to underpredict a state's well-controlled emissions, which are more likely in years farther in the future from the time of the rulemaking, include deferral of a large EGU's previously planned retirement date or increases in electricity demand that outpace the general trend of lower-emitting or non-emitting generation replacing higher-emitting generation. After considering the commenters' interest in greater predictability during the early years of the amended trading program as well as the need to protect against instances where the preset budgets could underpredict a state's well-controlled emissions in years farther from the year of the rulemaking, the EPA finds that the combination of these factors justifies the approach of using the higher of the two budgets for the control periods from 2026 through 2029.

In addition to the changes made in response to reliability-related comments, several other changes to the proposal being adopted primarily for other reasons will also help address the factors identified as reliability-related concerns. Most notably, the EPA is adopting changes to the dynamic budget computation procedure to incorporate multiple years of heat input data, which will reduce year-to-year variability in the budgets determined under that procedure and should to some extent reduce uncertainty about the quantities of allowances available for use in instances where a dynamic budget is being used instead of preset budget. In addition, the adoption of a 50-ton threshold before application of the 3-for-1 surrender ratio to emissions exceeding the backstop daily NO_X emissions rate should ensure that no unit incurs the higher surrender ratio solely because of unavoidable emissions during startup and should help address concerns that some units might be reluctant to operate because of the associated emissions-related costs. Also, the 2026–2027 phase-in of emissions reductions commensurate with installation of new SCR controls will increase the quantities of allowances available in the 2026 state emissions budgets for most states in the trading program.

To summarize: in light of the strong record supporting the feasibility of the emissions reductions required from EGUs; the use of a trading program as the mechanism for achieving those emissions reductions, with multiple options for achieving compliance and no requirements to cease operation of any individual EGU at any time; the established processes of RTOs, other balancing authorities, and state regulators for managing any EGU retirement requests that do occur in an orderly manner with evaluation of potential reliability impacts and implementation of mitigation measures where needed; the unbroken, decades-long historical success of the EPA's trading programs at achieving emissions reductions without any adverse reliability impacts; the views expressed by commenters that facilitating EGU retirement and replacement as a possible compliance strategy through 2029 would be particularly helpful; the changes made in the final rule for control periods through 2029 specifically to increase flexibility during this transitional period, including deferring application of the backstop daily emissions rate provisions for EGUs without existing SCR controls, increasing the target percentage used to determine the target allowance bank level for purposes of the bank recalibration provisions, and establishing preset state emissions budgets which serve as floors against potential dynamic budget imposition in those control periods; and the changes made in the final rule incorporating multiple years of heat input data into the dynamic budget-setting procedure, adding a 50-ton threshold before application of the 3-for-1 surrender ratio to emissions exceeding the backstop daily NO_X emissions rate, and phasing in emissions reductions requirements commensurate with new SCR installations through 2027; the EPA concludes that this action does not pose any material risk of adverse impact to electric system reliability.

The EPA has also considered the other suggestions offered by commenters for addressing reliability-related issues. With respect to suggestions that the rule should include provisions allowing some or all of the trading program's requirements to be suspended at times when an RTO or other entity with grid management responsibilities determines there is a reliability-related need, the EPA again observes that the rule's emissions reduction requirements are being implemented through a trading program mechanism which makes exceptions of this nature unnecessary. Trading programs inherently offer the flexibility to accommodate variability in the utilization of individual units. The ''reliability safety valve'' provisions in the Clean Power Plan, which one commenter cited as a precedent to support some form of temporary exemption under this rule, in fact was available only in situations where a state plan did not allow emissions trading and instead imposed unit-specific emissions constraints. *See* 80 FR 64877–879. Even the 3-for-1 allowance surrender ratio under the backstop daily NO_X emissions rate provisions can be met through the surrender of additional allowances. The rule does not bar any EGU from operating at any time as long as all allowance surrender requirements are met.

With respect to suggestions that the EPA must undertake recurring modeling of the evolving electrical system and consult with RTOs before each planned adjustment to emissions budgets, which start from the premise that the rule poses risk to electric system reliability that must be continuously monitored, the EPA disagrees with the premise and therefore also disagrees with the suggestions. As discussed in section V of this document, the EPA has taken care to ensure that the emissions reduction requirements applicable to EGUs under this rule are feasible through application of the control technologies selected as the basis of the emissions reductions. The EPA has also performed modeling in this rulemaking to assess the benefits and costs of the rule when all required emissions reductions are achieved. That modeling, which incorporates a representation of electrical grid regions and interregional constraints on energy and capacity exchange, affirms the feasibility of the overall emissions reduction requirements and is illustrative of a control strategy where some units retire and are replaced instead of installing new controls. The EPA has also consulted with the RTOs (as well as other balancing authorities) in the course of this rulemaking to ensure that the EPA understood the concerns expressed in their comments such that we could address those comments in this final rule. The EPA does not agree that further modeling or ongoing consultations with RTOs are needed in advance of the recurring dynamic budget adjustments, which do not increase the stringency of the rule's emissions reduction requirements established in the final rule. The extensive consultation processes adopted by the Agency in conjunction with the MATS rulemaking are not a relevant precedent; the MATS rule, which was promulgated to address a different statutory mandate, was structured in the form of unit-specific emissions constraints, fundamentally different from the requirements of this rule. The EPA notes that other entities responsible for maintaining reliability and managing entry and exit of resources, including the North American Electric Reliability Corporation (NERC) and RTOs and other balancing authorities, already routinely assess resource adequacy and reliability inclusive of meeting all regulatory requirements, including environmental requirements.

While the EPA does not agree that such consultations are a necessary precondition for successful implementation of this rule, the Agency remains available to engage with any affected EGU or reliability authority requesting to meet and discuss the intersection of its power sector regulatory programs with electric reliability planning and operations. The EPA is also continuing its practice of meeting with the U.S. Department of Energy and the Federal Energy Regulatory Commission to maintain mutual awareness of how Federal actions and programs intersect with the industry's responsibility to maintain electric reliability.[304]

The EPA is not adopting the suggestion to replicate the so-called ''safety valve'' mechanism created under the Revised CSAPR Update. That mechanism, cited by some commenters as potential precedent for an unspecified form of ''reliability safety valve'' in this action, gave owners of covered EGUs a one-time opportunity to voluntarily convert allowances banked under the Group 2 trading program to allowances useable in the Group 3 trading program at an 18-for-1 ratio for use in the trading program's initial control period in 2021. *See* 82 FR 23137–138. EGU owners chose to use the voluntary mechanism to acquire a total of 382 allowances, representing only 0.36 percent of the sum of the state emissions budgets and only 0.26 percent

[304] *See, e.g.,* U.S. Department of Energy and U.S. Environmental Protection Agency, Joint Memorandum on Interagency Communication and Consultation on Electric Reliability (March 8, 2023), available at *https://www.epa.gov/power-sector/electric-reliability-mou.*

of the total quantity of allowances available for compliance in that control period.[305] For the 2023 control period, the bank of allowances carried over from the 2022 control period plus the incremental starting bank that will be created by conversion of additional allowances banked under the Group 2 trading program (see section VI.B.12.b of this document) will total over 30 percent of the full-season emissions budgets.[306] Given the larger starting bank and this rule's bank recalibration provisions (which will be implemented starting with the 2024 control period, but which the EPA expects will increase allowance market liquidity starting with the 2023 control period), the Agency views establishment of a one-time voluntary conversion opportunity for the 2023 control period analogous to the Revised CSAPR Update's ''safety valve'' provision as unnecessary.

Finally, in the final rule the EPA is not adopting any of the other suggestions concerning additional mechanisms to make additional allowances available through auctions or RTO-administered allowance pools. For the reasons discussed throughout this section, the EPA concludes that the trading program as established in this action provides a flexible compliance mechanism that will allow the required emissions reductions to be achieved without the need for creation of additional allowances. However, the EPA also recognizes the potential for allowance market liquidity to be further increased through some form of auction mechanism. For instance, it may be appropriate to pair the introduction of an auction with a reduction in the bank recalibration percentage that begins earlier than 2030. Through a supplemental rulemaking, the Agency intends to propose and take comment on potential amendments to the Group 3 trading program that would add such an auction mechanism to the regulations and make other appropriate adjustments in the implementation framework at Step 4.[307]

2. Expansion of Geographic Scope

In light of the findings at Steps 1, 2, and 3 of the 4-step interstate transport framework, the EPA is expanding the geographic scope of the existing CSAPR NO_X Ozone Season Group 3 Trading Program to encompass additional states (and Indian country within the borders of such states) with EGU emissions that significantly contribute for purposes of the 2015 ozone NAAQS. Specifically, the EPA is expanding the Group 3 trading program to include the following states and Indian country within the borders of the states: Alabama, Arkansas, Minnesota, Mississippi, Missouri, Nevada, Oklahoma, Texas, Utah, and Wisconsin. Any unit located in a newly added jurisdiction that meets the applicability criteria for the Group 3 trading program will become an affected unit under the program, as discussed in section VI.B.3 of this document.

CSAPR, the CSAPR Update, and the Revised CSAPR Update also applied to sources in Indian country, although, when those rules were issued, no existing EGUs within the regions covered by the rules were located on lands that the EPA understood at the time to be Indian country.[308] In contrast, within the geographic scope of this rulemaking, the EPA is aware of areas of Indian country within the borders of both Utah and Oklahoma with existing EGUs that meet the program's applicability criteria. Issues related to state, tribal, and Federal CAA implementation planning authority with respect to sources in Indian country in general and in these areas in particular are discussed in section III.C.2 of this document. EPA's approach for determining a portion of each state's budget for each control period that will be set aside for allocation to any units in areas of Indian country within the state not subject to the state's CAA implementation planning authority is discussed in section VI.B.9 of this document.

Units within the borders of each newly added state will join the Group 3 trading program on one of two possible dates during the program's 2023 control period (that is, the period from May 1, 2023, through September 30, 2023). The reason that two entry dates are necessary is that, as discussed in section VI.B.12.a of this document, the effective date is expected to fall after May 1, 2023. In the case of states (and Indian country within the states' borders) whose sources do not currently participate in the CSAPR NO_X Ozone Season Group 2 trading program—Minnesota, Nevada, and Utah—the sources will begin participating in the Group 3 trading program on the rule's effective date. However, in the case of the states (and Indian country within the states' borders) whose sources do currently participate in the Group 2 trading program—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin—the sources will begin participating in the Group 3 trading program on May 1, 2023, regardless of the rule's effective date, subject to transitional provisions designed to ensure that the increased stringency of the Group 3 trading program as revised in this rulemaking will not substantively affect the sources' requirements prior to the rule's effective date. This approach provides a simpler transition for the sources historically covered by the Group 2 trading program than the alternative approach of being required to switch from the Group 2 trading program to the Group 3 trading program in the middle of a control period, and it is the same approach that was followed for sources that transitioned from the Group 2 trading program to the Group 3 trading program in 2021 under the Revised CSAPR Update. Section VI.B.12.a of this document contains further discussion of the rationale for this approach and the specific transitional provisions.

The EPA notes that under the rule, the expanded Group 3 trading program will include not only 19 states for which the EPA is determining that the required control stringency includes, among other measures, installation of new post-combustion controls, but also three

[305] Additional allowances available for compliance under the Group 3 trading program in the 2021 control period included a starting allowance bank created through mandatory conversion of a portion of the allowances banked under the Group 2 trading program as well as supplemental allowances issued to ensure that no provisions of the Revised CSAPR Update increasing regulatory stringency would take effect before that rule's effective date. *See* 86 FR 23133–137.

[306] The full-season emissions budgets for the 2023 control period under the Group 3 trading program and the incremental starting bank created in this action through conversion of additional Group 2 allowances (but not the bank of allowances carried over from the 2022 control period under the Group 3 trading program) will be prorated to reflect the portion of the 2023 ozone season occurring after the effective date of this rule. See sections VI.B.12.a. and VI.B.12.b.

[307] Such a rulemaking would not reopen any determinations which the Agency has made at Steps 1, 2, or 3 of the interstate transport framework in this action. Nor would it reopen any aspects of implementation of the program at Step 4 except for those in relation to establishing an auction and associated adjustments to ensure program stringency is maintained. In this respect, such a rulemaking would constitute a discretionary action that is not necessary to resolution of good neighbor obligations. Rather, these adjustments, if finalized, would reflect a shift from one acceptable form of implementation at Step 4 to a slightly modified but also acceptable form of implementation at Step 4, as related to EGUs. No legal or technical justification for this action as set forth in the record here depends on or would be undermined by the development of an alternative approach that includes an auction, and if the EPA for any reason determines not to propose or finalize such a rulemaking, no aspect of this rule would thereby be rendered infeasible or incomplete.

[308] CSAPR and the CSAPR Update both applied to EGUs located in areas within Oklahoma's borders that are now understood to be Indian country, consistent with the U.S. Supreme Court's decision in *McGirt* v. *Oklahoma,* 140 S. Ct. 2452 (2020) (and subsequent case law), clarifying the extent of certain Indian country within Oklahoma's borders. However, those rules were issued before the *McGirt* decision. *See* section III.C.2.a.

states—Alabama, Minnesota, and Wisconsin—for which the EPA is determining that the required control stringency does not include such measures. In previous rulemakings, the EPA has chosen to combine states in a single multi-state trading program only where the selected control stringencies were comparable, to ensure that states did not effectively shift their emissions reduction requirements to other states with less stringent emissions reduction requirements by using net out-of-state purchased allowances. Although the assurance provisions in the CSAPR trading programs were designed to address the same general concern about excessive shifting of emissions reduction activities between states, EPA chose not to rely on the assurance provisions as sufficient to allow for interstate trading in situations where the states were assigned differing emissions control stringencies.

In this rulemaking, the EPA believes the previous concern about the possibility that certain states might not make the required emissions reductions is sufficiently addressed through the various enhancements to the design of the trading program, even where states have been assigned differing emissions control stringencies. First, the existing assurance provisions are being substantially strengthened through the addition of the unit-specific secondary emissions limitations discussed in sections VI.B.1.c.ii and VI.B.8. Second, by ensuring that individual units operate their emissions controls effectively, the unit-specific backstop daily emissions rate provisions discussed in sections VI.B.1.c.i and VI.B.7 will necessarily also ensure that required emissions reductions occur within the state. With these enhancements to the design of the trading program, the EPA does not believe it is necessary for sources in Alabama, Minnesota, and Wisconsin to be excluded from the revised Group 3 trading program simply because their emissions budgets reflect a different selected emissions control stringency than the other states in the program.

The EPA's legal and analytic bases for expansion of the Group 3 trading program to each of the additional covered states, as well as responses to the principal related comments, are discussed in sections III, IV, and V of this document, respectively, and responses to additional comments are contained in the *RTC* document. With respect to the proposed approach of including all states covered by the rule in a single trading program even where the assigned control stringencies differ, the only comments received by the EPA supported the approach, which is finalized as proposed.

3. Applicability and Tentative Identification of Newly Affected Units

The Group 3 trading program generally applies to any stationary, fossil-fuel-fired boiler or stationary, fossil fuel-fired combustion turbine located in a covered state (or Indian country within the borders of a covered state) and serving at any time on or after January 1, 2005, a generator with nameplate capacity exceeding 25 MW and producing electricity for sale, with exemptions for certain cogeneration units and certain solid waste incineration units. To qualify for an exemption as a cogeneration unit, an otherwise-affected unit generally (1) must be designed to produce electricity and useful thermal energy through the sequential use of energy, (2) must convert energy inputs to energy outputs with efficiency exceeding specified minimum levels, and (3) may not produce electricity for sale in amounts above specified thresholds. To qualify for an exemption as a solid waste incineration unit, an otherwise-affected unit generally (1) must meet the CAA section 129(g)(1) definition of a ''solid waste incineration unit'' and (2) may not consume fossil fuel in amounts above specified thresholds. The complete text of the Group 3 trading program's applicability provisions and the associated definitions can be found at 40 CFR 97.1004 and 97.1002, respectively. The applicability of this rule to MWCs and cogeneration units outside the Group 3 trading program is discussed in sections V.B.3.a and V.B.3.c of this document, respectively, and MWC applicability criteria are further discussed in section VI.C.6 of this document.

In this rulemaking, the EPA did not propose and is not finalizing any revisions to the existing applicability provisions for the Group 3 trading program. Thus, any unit that is located in a newly added state and that meets the existing applicability criteria for the Group 3 trading program will become an affected unit under the program. The fact that the applicability criteria for all of the CSAPR trading programs are identical therefore is sufficient to establish that any units that are currently required to participate in another CSAPR trading program in any of the additional states where such other programs currently are in effect—Alabama, Arkansas, Minnesota, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin (including Indian country within the borders of such states)—will also become subject to the Group 3 trading program.

In the additional states where other CSAPR trading programs are not currently in effect—Nevada and Utah (including Indian country within the borders of such states)—units already subject to the Acid Rain Program under that program's applicability criteria (*see* 40 CFR 72.6) generally also meet the applicability criteria for the Group 3 trading program. Based on a preliminary screening analysis of the units in these states that currently report emissions and operating data to the EPA under the Acid Rain Program, the Agency believes that all such units are likely to meet the applicability criteria for the Group 3 trading program.

Because the applicability criteria for the Acid Rain Program and the Group 3 trading program are not identical, it is possible that some units could meet the applicability criteria for the Group 3 trading program even if they are not subject to the Acid Rain Program. Using data reported to the U.S. Energy Information Administration, in the proposal the EPA identified six sources in Nevada and Utah (and Indian country within the borders of the states) with a total of 15 units that appear to meet the general applicability criteria for the Group 3 trading program and that do not currently report NO_X emissions and operating data to the EPA under the Acid Rain Program. These units were listed in a table in the proposed rule, and the data from that table for these units are reproduced as Table VI.B.3–1 of this document. For each of these units, the table shows the estimated historical heat input and emissions data that the EPA proposed to use for the unit when determining state emissions budgets if the unit was ultimately treated as subject to the Group 3 trading program.[309] The EPA requested comment on whether each listed unit would or would not meet all relevant criteria set forth in 40 CFR 97.1004 and the associated definitions in 97.1002 to qualify for an exemption from the trading program and whether the estimated historical heat input and emissions data identified for each unit

[309] As discussed in section VI.B.10, any unit that becomes subject to the Group 3 trading program pursuant to this rule and that does not already report emissions data to the EPA in accordance with 40 CFR part 75 will not be required to report emissions data or be subject to allowance holding requirements under the Group 3 trading program until May 1, 2024, in order to provide time for installation and certification of the required monitoring systems. Such a unit will not be taken into account for purposes of determining state emissions budgets and unit-level allocations under the Group 3 trading program until the 2024 control period.

were representative. With respect to the listed units within the borders of Nevada or Utah, the EPA received no comments asserting either that the units qualified for applicability exemptions or that the estimated data identified by the EPA were unrepresentative.[310] For purposes of this rule, the EPA is therefore presuming that the units listed in Table VI.B.3–1 do not qualify for applicability exemptions and that the estimated data shown in the table for each unit are representative. However, the owners and operators of the sources retain the option to seek applicability determinations under the trading program regulations at 40 CFR 97.1004(c).

TABLE VI.B.3–1—ESTIMATED DATA TO BE USED FOR PRESUMPTIVELY AFFECTED UNITS WITHIN THE BORDERS OF NEVADA AND UTAH THAT DO NOT REPORT UNDER THE ACID RAIN PROGRAM

State	Facility ID	Facility name	Unit ID	Unit type	Estimated ozone season heat input (mmBtu)	Estimated ozone season average NO_X emissions rate (lb/mmBtu)	Notes
Nevada	2322	Clark	GT4	CT	190,985	0.0475	
Nevada	2322	Clark	GT5	CT	1,455,741	0.0191	
Nevada	2322	Clark	GT6	CT	1,455,741	0.0187	
Nevada	2322	Clark	GT7	CT	1,455,741	0.0178	
Nevada	2322	Clark	GT8	CT	1,455,741	0.0204	
Nevada	54350	Nev. Cogen. Assoc. 1—Garnet Val	GTA	CT	660,100	0.0377	1
Nevada	54350	Nev. Cogen. Assoc. 1—Garnet Val	GTB	CT	660,100	0.0387	1
Nevada	54350	Nev. Cogen. Assoc. 1—Garnet Val	GTC	CT	660,100	0.0387	1
Nevada	54349	Nev. Cogen. Assoc. 2—Black Mtn	GTA	CT	749,778	0.0323	1
Nevada	54349	Nev. Cogen. Assoc. 2—Black Mtn	GTB	CT	749,778	0.0370	1
Nevada	54349	Nev. Cogen. Assoc. 2—Black Mtn	GTC	CT	749,778	0.0364	1
Nevada	56405	Nevada Solar One	HI	Boiler	479,452	0.1667	
Nevada	54271	Saguaro	CTG1	CT	1,383,149	0.0314	1
Nevada	54271	Saguaro	CTG2	CT	1,383,149	0.0301	1
Utah	50951	Sunnyside	1	Boiler	1,888,174	0.1715	

Table notes:
[1] Unit reports capability of producing both electricity and useful thermal energy.

4. State Emissions Budgets

In this final rule, the EPA is using a combination of a ''preset'' budget calculation methodology and a ''dynamic'' budget calculation methodology to establish state emissions budgets for the Group 3 trading program. A ''preset'' budget is one for which the absolute amount expressed as tons per ozone season control period is established in this final rule. It uses the latest data currently available on EGU fleet composition at the time of this final action. A ''dynamic'' budget is one for which the formula and emissions-rate information is finalized in this rule, but updated EGU heat input and inventory information is used on a rolling basis to set the total tons per ozone season for each control period. Both methods of budget calculation are designed to set budgets reflective of the emissions control strategies and associated stringency levels (expressed as an emissions rate of pounds of NO_X per mmBtu) identified for relevant EGU types at Step 3—which we will refer to in this section as the ''Step 3 emissions control stringency.'' Preset budgets provide greater certainty for planning purposes and can be reliably established in the short-term based on known, upcoming changes in the EGU fleet. Due to build time for new units and planning and approval processes for plant retirements, these major fleet alterations are often known several years in advance. This information facilitates presetting budgets that appropriately calibrate the identified control stringency to the fleet. Dynamic budgets better assure that the budgets remain commensurate with the Step 3 emissions control stringency over the longer term, as currently unknown changes in the EGU fleet occur. In this final rule, in response to comments, we have adjusted the proposal to give a greater role for preset budgets through 2029, while dynamic budgeting will be phased in to provide greater certainty in the short term and allow for a transition period to an exclusively ''dynamic'' approach beginning in 2030.

For the control periods from 2023 through 2025, the preset budgets established in the rule will serve as the state emissions budgets for the control periods in those years, with no role for dynamic budgeting. For the control periods from 2026 through 2029, the EPA is determining preset emissions budgets for each control period in the rule and will also calculate and publish dynamic budgets for each state in the year before each control period using the dynamic budget-setting methodology finalized in this rule, applied to data available at the time of the calculations. For these four control periods, each state's preset budget serves as a floor and may be supplanted by the dynamic emissions budget EPA calculates for the state for that control period only if the dynamic budget is higher than the preset budget. For control periods in 2030 and thereafter, the state emissions budgets will be the dynamic budgets calculated and published in the year before each control period.

In the dynamic budget calculation methodology, it is the fleet composition (reflected by heat input patterns across the fleet in service, inclusive of EGU entry and exit) that is dynamic, while the emissions stringency finalized in this rule is constant, as reflected in

[310] One commenter expressed the view that eight of the listed units within Nevada's borders appear to meet the CSAPR applicability criteria but provided no comments on the specific proposed data. See comments of Berkshire Hathaway Energy, EPA–HQ–OAR–2021–0668–0554, at 58–59. The EPA also received comments concerning sources within Delaware's borders that were included in the proposal's request for comment; these comments are moot because Delaware is not being added to the Group 3 trading program in the final rule. See comments of Calpine, EPA–HQ–OAR–2021–0668–0515; comments of Delaware City Refining, EPA–HQ–OAR–2021–0668–0309.

emissions rates for various types of units. Multiplying the assumed emissions rate for each unit (as finalized in this rule) by the identified recent historical heat input for each unit and summing the results to the state level would provide a given year's state dynamic emissions budgets. Dynamic budgets are a product of the formula promulgated in this action applied to a rolling three-year average of reported heat input data at the state level and a rolling highest-three-of-five-year average of reported heat input data at the unit level. As such, the EPA is confident that dynamic budgets will more accurately reflect power sector composition, particularly in later years, and certainly from 2030 and beyond, than preset budgets could and will therefore better implement the Step 3 emissions control stringency over long time horizons.

Starting in 2025 (for the 2026 control period), the dynamic budgets, along with the underlying data and calculations will be publicly announced, and this will occur approximately one year before the relevant control period begins. These will be published in the **Federal Register** through notices of data availability (NODAs), similar to how other periodic actions that are ministerial in nature to implement the trading programs are currently handled. And as with such other actions, interested parties will have the opportunity to seek corrections or administrative adjudication under 40 CFR part 78 if they believe any data used in making these calculations, or the calculations themselves, are in error.

To illustrate how dynamic budgeting will work after the transition from preset budgets, the dynamic budgets for the 2030 ozone season control period will be identified by May 1, 2029, using the latest available average of three years of reported operational data at that time (*i.e.,* the average of 2026–2028 heat input data at the state level and 2024–2028 years of rolling data at the unit level) applied in a simple mathematical formula finalized in this rule, which multiplies this heat input data by the emissions rates quantified in this rule. Therefore, if a unit retires before the start of the 2028 ozone season but had not announced its upcoming retirement at the time of this rule's finalization, the dynamic budget approach ensures that the dynamic budgets for 2030 and subsequent control periods would represent the identified control stringency applied to a fleet reflecting that retirement.

The two examples discussed next illustrate the implementation of the dynamic budget during the 2026–2029 time period. During this period, the state emissions budget for each state for a given control period will be the preset state emissions budget unless the dynamic budget is higher. This approach accommodates scenarios where baseline fossil heat input may exceed levels anticipated by EPA in the preset budgets (*e.g.,* this could result from greater electric vehicle penetration rates). Table VI.B.4–1 illustrates this scenario. In the preset budget approach for 2028, the 2028 heat input is estimated based on the latest available heat input data at the time of rule proposal (*i.e.,* 2021; see the subsection on preset budget methodology later in this section), which cannot reflect a subsequent change in fleet heat input values (column 2) due to, *e.g.,* increased utilization to meet increased electric load. However, the dynamic budget would use 2022–2026 heat input values at the unit level and 2024–2026 heat input values at the state level—as opposed to 2021 heat input values—as the latest representative values to inform the 2028 state emissions budget. Therefore, the heat input values in column 2 under the dynamic scenario reflect the change in fleet utilization levels, and when multiplied by the emissions rates reflecting the Step 3 emissions control stringency in this final rule, the corresponding emissions (18,700 tons) summed in column 4 constitute a state budget that more accurately reflects the Step 3 emissions control stringency applied to the fleet composition for that year, as opposed to the 17,000 tons identified in the preset budget approach. As illustrated in the example, the dynamic variable is the heat input variable, which changes over time. In this instance, the dynamic budget value of 18,700 tons would be implemented for 2028 instead of the preset value, and thus accommodate the unforeseen utilization changes in response to higher demand.

In the second table, Table VI.B.4–2, the dynamic budget is lower than the preset budget due to retirements that were not foreseen at the time the preset budgets were determined. In the preset budget approach for 2028, the 2028 heat input is still estimated based on the latest available heat input data at the time of rule proposal (*i.e.,* 2021), which cannot reflect a subsequent fleet change in heat input values due to an unanticipated retirement of one of the state's coal-fired units before the start of the 2028 ozone season. However, the dynamic budget again would use 2022–2026 heat input values at the unit level and 2024–2026 heat input values at the state level—as opposed to 2021 heat input values—as the latest representative values to inform the 2028 state emissions budget, which would reflect the decline in coal heat input and replacement with natural gas heat input (capturing the coal unit's retirement). Therefore, the heat input values under the dynamic budget scenario reflect the change in fleet composition, and when multiplied by the relevant emissions rates reflecting the Step 3 emissions control stringency identified in this final rule, the corresponding emissions (15,000 tons) constitute a state budget that reflects the identified control stringency applied to the fleet composition for that year as opposed to the 17,000 tons in summed in the first table. However, for the 2026–2029 period, in which the EPA implements an approach that utilizes the higher of the dynamic budget or preset budget, the budget implemented for 2028 in this scenario would be the 17,000 ton preset amount.

During the 2026–2029 transition period—during which substantial, publicly announced utility commitments exist for higher emitting units to exit the fleet—it is still possible that yet-to-be known, unit-specific retirements (such as illustrated in this second scenario) may result in dynamic budgets that are lower than the preset budgets finalized in this rule. However, during this transition period EPA believes that having the preset budgets serve as floors for the state emissions budgets is appropriate for two primary reasons identified by commenters. First, commenters repeatedly emphasized the need for certainty and flexibility to successfully carryout plans for significant fleet transition through the end of the decade. The 2026–2029 period is expected to have substantial fleet turnover. Current Form EIA–860 data, in which utilities report their retirement plans, identify 2028 as the year with the most planned coal capacity retirements during the 2023–2029 timeframe. Using preset budgets as state emissions budget floors provides states and utilities with information on minimum quantities of allowances that can be used for planning purposes. In turn, this fosters the operational flexibility needed while putting generation and transmission solutions into place to accommodate such elevated levels of retirements. Second, the latter part of the decade has a significant amount of unit-level firm retirements already planned and announced for purposes of compliance with other power sector regulations or fulfillment of utility commitments. These known retirements are already captured in the preset state budgets, with the result that the likelihood and magnitude of instances where a state's dynamic budget for a given control period would be lower than its preset budget for the control period is reduced in this 2026–2029 period relative to control periods further in the future for which retirement plans have not yet been announced. After 2029, the dynamic budgets from 2030 forward will fully capture all prior retirements and new builds when the fleet is entering this period where unit-specific data on such plans is less frequently available. For instance, through the remaining portion of the decade, the amount of coal steam retirements identified and reported through Form EIA–860 is nearly 7 GW each year. However, for the decade beginning in 2030—the amount of capacity currently reported with a planned retirement is less than 2 GW each year.[311] This yet-to-be available data and relative lack of currently known firm retirement plans for 2030 and beyond make dynamic budget implementation for those years essential for state emissions budgets to maintain the Step 3 control stringency required under this rule.

TABLE VI.B.4–1—EXAMPLE OF PRESET AND DYNAMIC BUDGET CALCULATION IN SCENARIO OF INCREASED FOSSIL HEAT INPUT

	Preset budget approach (2028)			Dynamic budget approach (2028)		
	Preset heat input (tBtu)	Preset emissions rate (lb/mmBtu)	Preset tons (heat input × emissions rate)/2000	Heat input (tBtu)	Emissions rate (lb/mmBtu)	Tons (heat input × emissions rate)/2000
Coal Units	600	0.05	15,000	660	0.05	16,500
Gas Units	400	0.01	2,000	440	0.01	2,200
State Budget (tons)			17,000			18,700

TABLE VI.B.4–2—EXAMPLE OF PRESET AND DYNAMIC BUDGET CALCULATION IN SCENARIO OF UNANTICIPATED RETIREMENT

	Preset budget approach (2028)			Dynamic budget approach (2028)		
	Preset heat input (tBtu)	Preset emissions rate (lb/mmBtu)	Preset tons (heat input × emissions rate)/2000	Heat input (tBtu)	Emissions rate (lb/mmBtu)	Tons (heat input × emissions rate)/2000
Coal Units	600	0.05	15,000	500	0.05	12,500
Gas Units	400	0.01	2,000	500	0.01	2,500
State Budget (tons)			17,000			15,000

In summary, for the control periods in 2023 through 2025, EPA is providing only preset budgets in this final rule because those control periods are in the immediate future and would not substantially benefit from the use of future reported data. For these years, the certainty around new builds and retirements is higher than ensuing years. For the ozone season control periods of 2026 through 2029, EPA is providing both preset budgets in this final rule and dynamic budgets via future ministerial actions. For those control periods from 2026 through 2029, the preset budgets finalized in this rule serve as floors, such that a given state's dynamic budget ultimately calculated and published for that control period will apply to that state's affected EGUs only if it is higher than the corresponding preset budget finalized in this rulemaking. This approach is in response to stakeholder comments requesting more advance notice regarding the total quantities of allowances available to accommodate compliance planning through the latter half of the decade, during a period of particularly high fleet transition expected with or without this rulemaking.

EPA's emissions budget methodology and formula for establishing Group 3 budgets are described in detail in the Ozone Transport Policy Analysis Final Rule TSD and summarized later in this section.

a. Methodology for Determining Preset State Emissions Budgets for the 2023 Through 2029 Control Periods

To compose preset state emissions budgets, the EPA is using the best available data at the time of developing this final rule regarding retirements and new builds. The EPA relies on a compilation of data from Form EIA–860 (where facilities report their future retirement plans), the PJM Retirement Tracker, utilities' integrated resource plans, notification of compliance plans with other EPA power sector regulatory requirements, and other information sources that EPA routinely canvasses to populate the data fields included in the Agency's NEEDS database. The EPA has updated this data on retirements and new builds using the latest information available from these sources at the time of final rule development as well as input provided by commenters.

For determining preset state emissions budgets, the EPA generally uses historical ozone season data from the 2021 ozone season, the most recent data available to EPA and to commenters responding to this rulemaking's proposal and providing a reasonable representation of near-term fleet conditions. This is similar to the approach taken in the CSAPR Update and the Revised CSAPR Update, where

[311] See 2021 Form EIA Form 860—Schedule 3, Generator Data. Department of Energy, Energy Information Administration.

the EPA likewise began with data for the most recent ozone season at the time of proposal (2015 and 2019, respectively).

By using historical unit-level NO_X emissions rates, heat input, and emissions data in the first stage of determining preset emissions budgets, the EPA is grounding its budgets in the most recent representative historical operation for the covered units at the time EPA began its final rulemaking. This data set is a reasonable starting point for the budget-setting process as it reflects recent publicly available and quality assured data reported by affected facilities under 40 CFR part 75, largely using CEMS. The reporting requirements include quality control measures, verification measures, and instrumentation to best record and report the data. In addition, the designated representatives of EGU sources are required to attest to the accuracy and completeness of the data.

The first step in deriving the future year state emissions budget is to calibrate historical data to planned future fleet conditions. EPA does this by adjusting this historical baseline information to reflect the known changes (*e.g.,* when deriving the 2023 state emissions budget, EPA starts by adjusting 2021 unit-level data to reflect changes announced and planned to occur by 2023). The EPA adjusted the 2021 ozone-season data to reflect committed fleet changes expected to occur in the baseline. This includes announced and confirmed retirements, new builds, and retrofits that occur after 2021 but prior to 2023. For example, if a unit emitted in 2021, but retired prior to May 1, 2022, its 2021 emissions would not be included in the 2023 baseline estimate. For units that had no known changes, the EPA uses the actual emissions, heat input, and emissions rates reported for 2021 as the baseline starting point for calculating the 2023 state emissions budgets. Using this method, the EPA arrived at a baseline emission, heat input, and emissions rate estimate for each unit for a future year (*e.g.,* 2023).

The second step in deriving the preset state emissions budgets is for EPA to take the adjusted historical data from Step 1, and adjust the emissions rates and mass emissions to reflect the control stringencies identified as appropriate for EGUs of that type. For instance, if an SCR-equipped unit was not operating its SCR so as to achieve a seasonal average emissions rate of 0.08 lb/mmBtu or less in the historical baseline, the EPA lowered that unit's assumed emissions rate to 0.08 lb/mmBtu and calculated the impact on the unit's mass emissions. Note that the heat input is held constant for the unit in the process, reflecting the same level of unit operation compared to historical 2021 data. The improved emissions rate of 0.08 lb/mmBtu is applied to this constant heat input, reflecting control optimization. In this manner, the unit-level totals from Step 1 are adjusted to reflect the additional application of the assumed control technology at a given control stringency. This is illustrated in Table VI.B.4.a–1. Row 1 reflects the 2021 historical data for this SCR-controlled unit. Row 2 reflects no change (as there are no known changes such as planned retirement or coal-to-gas conversion). Row 3 reflects application of the Step 3 stringency (*i.e.,* a 0.08 lb/mmBtu emissions rate from SCR optimization). The resulting impact on emissions is a reduction from the historical 4,700 tons to an expected future level of 615 tons. A state's preset budget for a given control period is the sum of the amounts computed in this manner for each unit in the state for the control period.

TABLE VI.B.4.a–1—EXAMPLE OF UNIT-LEVEL DATA CALCULATIONS FOR DERIVING STATE EMISSIONS BUDGETS

	Heat input (tBtu)	Emission rate (lb/mmBtu)	Emissions (tons)
Historical Data (2021)	15.384	0.61	4,700
Step 1 (Baseline)—Historical data adjusted for planned changes	15.384	0.61	4,700
Step 2—Baseline further adjusted for Step 3 stringency	15.384	0.08	615

For each control period from 2026 onward, the unit-specific emissions rates assumed for all affected states except Alabama, Minnesota, and Wisconsin will reflect the selected control stringency that incorporates post-combustion control retrofit opportunities for the relevant units identified in the state emissions budgets and calculations appendix to the Ozone Transport Policy Analysis Final Rule TSD. The emissions rates assigned to large coal-fired EGUs for 2026 state emissions budget computations only reflect 50 percent of the SCR retrofit emissions reduction potential at each of those units, to capture the phase-in approach EPA is taking for this control as described in section VI.A of this document. The EPA calculates these unit-level emissions rates in 2026 as the sum of the unit's baseline emissions rate and its controlled emissions rate divided by two (*i.e.,* 50 percent of the emissions reduction potential of that pollution control measure). The emissions rates assigned to these large coal-fired EGUs for 2027 state emissions budget computations reflect the full assumed SCR retrofit emissions potential at those units, by applying the controlled emissions rate only. For example, a coal steam unit greater than or equal to 100 MW currently lacking a SCR and emitting at 0.20 lb/mmBtu would be assumed to reduce its emissions rate to 0.125 lb/mmBtu rate in 2026 and 0.050 lb/mmBtu rate in 2027 for purposes of deriving its preset state emissions budgets in those years.

Comment: Some commenters suggested that EPA should not reflect planned retirements in its preset budgets. The suggestion stems from commenters' observation that those retirement decisions may yet change.

Response: The effectiveness of EPA's future year preset state emissions budgets depends on how well they are calibrated to the expected future fleet. Therefore, EPA believes it is important to incorporate expected new builds, retirements, and unit changes already slated to occur. Ignoring these factors would dilute, rather than strengthen, the ability of preset budgets to capture the most representative fleet of EGUs to which they will be applied. Omitting scheduled retirements and new builds from state emissions budgets would reflect units that power sector operators and planning authorities do not expect to exist, while failing to reflect units that are expected to exist.

EPA notes it is using the best available data at the time of the final rule. EPA relies on a compilation of data from Form EIA–860 where facilities report their future retirement plans. In addition, EPA is using data from regional transmission organizations who are cataloging, evaluating, and approving such retirement plans and data; data from notifications submitted directly to EPA by the utility themselves through comments; and retirement notifications submitted to permitting authorities. This information is highly reliable, real-world information that provides EPA with the high confidence that such retirements will in fact occur.

If a unit's future retirement does not occur on the currently scheduled date, EPA observes that such an unexpected departure from the currently available evidence would still not undermine the ability of affected EGUs to comply with their applicable state budgets. EPA's approach of using historical data and incorporation only of announced fleet changes in estimating its future engineering analytics baseline means that its future year baseline generation and retirement outlook for higher emitting sources is more likely to understate future retirements (rather than overstate as suggested by commenter), as EPA does not assume for the purpose of preset budget quantification any retirements beyond those that are already planned. In other words, in the 2023 through 2029 timeframe for which EPA is establishing preset state emissions budgets in this rulemaking, there are more likely to be additional future EGU retirements beyond those scheduled prior to the finalization of this rule than there are to be reversed or substantially delayed changes to already announced EGU retirement plans. For instance, subsequent to the EPA's finalization of the Revised CSAPR Update Rule budgets for 2023 (rule finalized in March 2021), the owners of Sammis Units 5–7 and Zimmer Unit 1 in Ohio (totaling nearly 3 GW of coal capacity) announced that the units would retire by 2023—nearly 5 years earlier than previously planned.[312] [313] These coal retirements were not captured in Ohio's 2023 or 2024 state emissions budgets established under the Revised CSAPR Update. Meanwhile, there have been no announcements of previously announced retirement plans being rescinded or delayed for other Ohio units. Similarly, the Joppa Power Plant in Illinois accelerated its retirement from 2025 to 2022 shortly after the Revised CSAPR Update Rule was signed.[314]

We further observe that the commenters' concern is only materially meaningful for the 2023 through 2025 preset budget periods, where the currently known information is generally the most reliable. For the 2026–2029 control periods, if an anticipated fleet change such as an EGU retirement does not actually occur, the dynamic budget setting methodology would, all else being equal, generate a budget reflective of that unit's continued operation (as the budget would be based on the preceding years of historical data), and that dynamic budget will supplant the preset budget for that state (if it represents a total quantity of emissions higher than the preset budget).

Because the future is inherently uncertain, all analytic tools and information resources used in any estimation of future EGU emissions will yield some differences between the projected future and the realized future. Such potential differences may either increase or decrease future emissions in practice, and the unavoidable existence of such differences does not, on its own, render the EPA's inclusion of currently announced retirements an unreasonable feature of the methodology for determining future year preset emissions budgets. To the contrary, if the EPA failed to include these announced retirements, the rule would knowingly authorize amounts of additional, sustained pollution that are not currently expected to occur. If those retirements largely or entirely occur as currently scheduled, the overestimated state budgets would allow other EGUs to emit additional pollution in place of the emissions from the retired EGUs instead of maintaining or improving their emissions performance to eliminate significant contribution with nonattainment and interference with maintenance of the NAAQS.[315]

Additionally, as noted elsewhere, EPA's use of a market-based program, a starting bank of converted allowances, and variability limits are all features that will readily accommodate whatever relatively limited differences in emissions may occur if a currently scheduled EGU retirement is ultimately postponed during the preset budget years of 2023 through 2025. Therefore, EPA's resulting preset state emissions budgets—inclusive of expected fleet turnover—are robust to the inherent uncertainty in future year baseline conditions for the period in which they are applied.

Comment: Some commenters suggested that EPA should use a multi-year baseline for all of its state budget derivations, including preset budgets, to control for outlier years that may not be representative of future years due to major weather events or other fleet disruptions (such as a large nuclear unit outage).

Response: For preset state emissions budget derivation, EPA is finalizing use of the same single-year[316] historical baseline approach it used in the proposed rule. This approach is similar to the Revised CSAPR Update, where EPA also relied on a single-year historical baseline to inform its Step 3 approach. EPA's interest in a historical data set to inform this part of the analysis is to capture the most representative view of the power sector. For estimating preset state budgets, EPA finds that, particularly at the state level, more recent data is a better representation and basis for future year baselines rather than incorporating older data. Taking as an example preset budget estimation for the 2023 through 2025 ozone seasons, the EPA is able to compare its single-year base line to an alternative multi-year baseline (*e.g.,* a 3-year baseline encompassing 2020–2022) and determine that the single year baseline better reflects future fleet operation expectation than a multi-year baseline that incorporates units which have since retired as well as outlier patterns in load during pandemic-related shutdowns.

EPA recognizes that 2021 is the latest available historical data as of the preparation of this rulemaking, and therefore the most up-to-date picture of the fleet at the time EPA began its analysis. EPA then further evaluates the 2021 historical data at the state level to determine whether it was a representative starting point for estimating future year baseline levels and subsequently deriving the preset state emissions budgets. If the Agency finds any state-level anomalies, it makes necessary adjustments to the data. While unit-level variation may occur from year-to-year, those variations are often offset by substitute generation from other units within the state. Therefore, EPA conducts its first screening at the state level by identifying any states where 2021 heat

[312] Available at *https://www.prnewswire.com/news-releases/energy-harbor-transitions-to-100-carbon-free-energy-infrastructure-company-in-2023-301501879.html*.

[313] Available at *https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/coal/071921-vistra-plans-to-retire-13-gw-zimmer-coal-plant-in-ohio-five-years-early*.

[314] Available at *https://www.prnewswire.com/news-releases/joppa-power-plant-to-close-in-2022-as-company-transitions-to-a-cleaner-future-301263013.html*.

[315] Some of these announced retirements reflect the operator's reported intention to EPA to retire the affected capacity by that time as part of their compliance with effluent limitation guidelines or with the coal combustion residuals rule.

[316] For the purposes of this rulemaking, when describing a ''year'' or ''years'' of data utilized in state emission budget computations, the EPA is actually utilizing the relevant data from May 1 through September 30 of the referenced year(s), consistent with the control period duration of this rule's EGU trading program.

input and 2021 emissions were the lowest year for heat input and emissions relative to the past several years (2018–2022, excluding 2020 due to shut downs and corresponding reduced utilization related to the pandemic onset).[317] [318] Then, for that limited number of states (AL, LA, MS, and TX) in which 2021 reflects the minimum fossil fuel heat input and minimum emissions over the baseline evaluation period, EPA—similar to prior rules—evaluated whether any unit-level anomalies in operation were driving this lower heat input at the state level. EPA examined unit-level 2021 outages to determine where an individual unit-level outage might yield a significant difference in state heat input, corresponding emissions baseline and resulting state emissions budgets. When applying this test to all of the units in the previously identified states (and even when applying to EGUs in all states for whom Federal implementation plans are finalized in this rulemaking), the EPA determined that the only unit with a 2021 outage that (1) decreased its output relative to preceding or subsequent years by 75 percent or more (signifying an outage), and (2) could potentially impact the state's emissions budget substantially as it constituted more than 5 percent of the state's heat input in a non-outage year was Daniel Unit 2 in Mississippi. EPA therefore adjusted this state's baseline heat input and NO_X emissions to reflect the operation of this unit based on its 2019 data—which was the second most recent year of data available at the time of proposal (excluding 2020 given atypical impacts from pandemic-related shutdowns) for which this unit operated. The EPA then applied the Step 3 mitigation strategies as appropriate to this unit (*i.e.,* combustion controls upgrade in 2024, SCR retrofit in 2026/2027) to derive this portion of Mississippi's budget. This test, and subsequent adjustment as necessary, enables EPA to utilize the latest, most representative data in a manner that is robust to any substantial state-level or region-level outlier events within that dataset and further validates EPA's comprehensive approach to using the most recent single year of data for preset budgets.

b. Methodology for Determining Dynamic State Emissions Budgets for Control Periods in 2026 onwards

In this final rule, the EPA is finalizing an approach of using multi-year baseline data for purposes of dynamic budget computation. The aforementioned testing of the representative nature of a single year of baseline data for purposes of preset budget setting is not possible in the dynamic budget process as that data will not be available until a later date. Further, the EPA generally agrees with commenters that use of a multi-year period will be more robust to any unrepresentative outlier years in fleet operation and thus better suited for purposes of dynamic budgets. The methodology for determining dynamic state emissions budgets for later control periods (2026 and beyond) relies on a nearly identical methodology for applying unit-level emissions rate assumptions as the preset budget methodology. But it uses more recent heat input data that will become available by that future time, employing a multi-year approach for identifying the heat input data so as to ensure representativeness.

For dynamic budgets, EPA uses more years of baseline data to control for any state-level and unit-level variation that may occur in a future single year that is not possible to identify at present. First, for each unit operating in the most recent ozone season for which data have been reported, EPA identifies the average of the three highest unit-level heat input values from the five ozone seasons ending with that ozone season to get a representative unit-level heat input. Ozone seasons for which a unit reported zero heat input are excluded from the averaging of the three highest heat input values for that unit. These representative unit-level heat input values established for each unit individually are then summed for all units in each state. Each unit's representative unit-level heat input is then divided into this state-level sum to get that unit's representative percent of the aggregated average heat input values for all affected EGUs in that state.

Next, EPA calculates a representative state-level heat input by taking the average state-level total heat input across affected EGUs from the most recent three ozone seasons for which data have been reported, to which the above-derived representative unit-level percentages of heat input are applied. The EPA uses a three-year baseline period for state-level heat input versus the five-year baseline period noted previously for unit-level heat input because there is less variation from year to year at the state level compared to the unit level. Multiplying the representative unit-level percentages of heat input by the representative state-level heat input yields a normalized unit-level heat input value for each affected EGU. This step assures that the total heat input being reflected in a dynamic state budget does not exceed the average total heat input reported by affected EGUs in that state from the three most recent years. Finally, each normalized unit-level heat input value is multiplied by the emissions rate reflecting the assumed unit-specific control stringency for each particular year (determined at Step 3) to get a unit-level emissions estimate. These unit-level emissions estimates are then summed to the state level to identify the dynamic budget for that year. This procedure to derive normalized unit-level heat input is captured in the following table:

TABLE VI.B.4.b–1—DERIVATION OF NORMALIZED UNIT-LEVEL HEAT INPUT

[Illustrative]

	2022 Heat input	2023 Heat input	2024 Heat input	2025 Heat input	2026 Heat input	Representative unit-level heat input (avg of 3 highest of past 5)	Representative unit-level percent	Representative state level heat input (avg 3 most recent state totals)	Normalized unit—level heat input
Unit A	100	200	150	200	300	233	41%	483	199
Unit B	50	100	200	50	100	133	24	483	114
Unit C	250	150	150	200	100	200	35	483	170

[317] EPA identified states for which 2021 both heat input and emissions were the low year among the examined baseline period as a preliminary screen to identify potential instances where reduced utilization may lead to an understated emissions baseline value.

[318] EPA also conducted a similar test to identify states in which 2021 heat input and emissions were the high year among the examined baseline period and found that it was for both Utah and Pennsylvania. However, for both states the elevated heat input trend persisted into 2022 (at slightly lower levels and was correlated with retirements elsewhere in the region—indicating that some of this heat input increase may be representative of the future fleet and that planned retirements factored into preset budget will remove any unrepresentative heat input from 2021.

TABLE VI.B.4.b–1—DERIVATION OF NORMALIZED UNIT-LEVEL HEAT INPUT—Continued

[Illustrative]

	2022 Heat input	2023 Heat input	2024 Heat input	2025 Heat input	2026 Heat input	Representative unit-level heat input (avg of 3 highest of past 5)	Representative unit-level percent	Representative state level heat input (avg 3 most recent state totals)	Normalized unit—level heat input
State Total	400	450	500	450	500	567			

The EPA will issue these dynamic budget quantifications approximately 1 year before the relevant control period. We view such actions as ministerial in nature in that no exercise of agency discretion is required. For instance, starting in early 2025, the EPA would take the most recent three years of state-level heat input data and the most recent five years of unit-level heat input data and calculate 2026 state emissions budgets using the methodology described previously. For 2026–2029, EPA is establishing the preset state emissions budgets finalized in this rulemaking and will only supplant those preset emissions budgets with the to-be-published dynamic emissions budgets if, for a given state and a given control period, that dynamic budget yields a higher level of emissions than the corresponding preset budget finalized in this rulemaking. For 2030 and beyond, the EPA solely uses the dynamic budget process.

By March 1 of 2025, and each year thereafter, the EPA will make publicly available through a NODA the preliminary state emissions budgets for the subsequent control period and will provide stakeholders with a 30-day opportunity to submit any objections to the updated data and computations. (This process will be similar to the releases of data and preliminary computations for allocations from new unit set-asides that is already used in existing CSAPR trading programs.) By May 1 of 2025, and each year thereafter, the EPA will publish the dynamic budgets for the ozone-season control period in the following calendar year. Through the 2029 ozone season control period, these budgets will only be imposed if the applicable dynamic state budget is higher than the corresponding preset state budget finalized in this rulemaking. Preliminary and final unit-level allowance allocations for the units in each state in each control period will be published on the same schedule as the dynamic budgets for the control period. For the control periods from 2026 through 2029, the allocations will reflect the higher of the preset or dynamic budget for each state, and after 2030, the allocations will reflect the dynamic budgets. Additional details, corresponding data and formulas, and examples for the dynamic budget are described in the Ozone Transport Policy Analysis Final Rule TSD.

Comment: Multiple commenters claimed that designing a dynamic budget process that relies on a single year of yet-to-be known heat input data may produce an unrepresentative view of fleet operations for the immediate ensuing years. Commenters pointed to the hypothetical of another pandemic-like year (*e.g.,* 2020) occurring in the future, noting that 2020 would have been a poor choice for estimating 2022 fleet operation and the same would likely hold true if a similar event occurred, for example, in 2025—that would consequently make that year a poor choice as a representative of 2027 baseline. They further pointed out that severe weather events and operating disruptions (a large nuclear plant outage) can similarly render a single year baseline a risky choice to inform future expectations.

Response: Insofar as the commenters are addressing the reference period for dynamic budget computation regarding years of data that have not yet occurred and therefore not currently available for evaluating their representative nature, EPA agrees and is incorporating a rolling 3-year baseline at the state level and a rolling 5-year baseline at the unit level for determining dynamic budgets in this final rule. These multi-year rolling baseline (or reference periods) will minimize any otherwise undue impact from individual years where fleet-level or unit-level heat input was uncharacteristically high or low. EPA determined that such an approach, while not needed for preset budgets, is necessary in the case of dynamic budgets because the baseline in that instance is occurring in a future year and therefore is not knowable and available to test for representativeness at the time of the final rule. To control for this type of uncertainty, the EPA finds it appropriate to use a multi-year baseline in this instance per commenter suggestion. While a multi-year baseline may have a slight drawback of using a slightly more dated past fleet performance (including emissions from higher emitting EGUs that may have subsequently reduced utilization by the target year for which the dynamic budget is being calculated) to estimate the expected future fleet performance at the emissions performance levels determined by the Step 3 result in this rulemaking, that drawback is worth the advantage of protecting against instances where atypical circumstances in the most recent single year may occur and not be representative of the subsequent year for which the dynamic budget is being estimated. This singular drawback of moving to a multi-year baseline is most pronounced in the early years of dynamic budgeting. Therefore, EPA is able to lessen the impact of this drawback of the multi-year baseline by extending the earliest start date of dynamic budgets from 2025 (as proposed) to 2026 in the final rule.

Comment: Commenters suggested that the dynamic budget procedure would not provide enough advance notice of state budget and unit level allocation for sources to adequately plan future year operation.

Response: EPA disagrees with the notion that the timing of the dynamic budget determination would occur too close to the control period to allow adequate operations planning for compliance. As described previously, the dynamic budget level would be provided approximately 1 year in advance of the start of the control period (*i.e.,* around May 1), and the allowance allocations would occur on July 1, approximately 10 months prior to the start of the compliance period. Not only is this an adequate amount of time as demonstrated by the successful implementation of past rules that have been finalized and implemented within several months of the beginning of the first affected compliance period (*e.g.,* Revised CSAPR Update), but EPA notes it is maintaining similar trading program flexibility and banking flexibilities of past programs which provide further opportunities for sources to procure allowances and plan for any future operating conditions. Finally, as noted previously, the EPA is providing preset budgets for the years 2023–2029, which serve as an effective floor on the state's ultimate emissions budget level for years 2026–2029, as states will receive the higher of the preset or dynamic budget for those years. This provision of certain preset state emissions budgets serving as a floor level for 2026–2029 should further assuage commenters' concerns regarding planning certainty about allowance allocations and state emissions budget levels during this period of power sector transition to cleaner energy sources.

Comment: Commenters raised concerns that there is a two-year lag in the dynamic budgets in that, for example, for the dynamic budget in the 2026 control period, the calculations will be based on heat input and inventory information reflective of data through 2024. Commenters contend that, if there is a much greater need for allowances for compliance due to unavoidable or unforeseen need for a higher amount of heat input than reflected in prior years' data, the budget for that control period will not reflect this need, and the allowances will only become available when the dynamic budget is calculated using that information (*i.e.,* 2025 data would be reflected starting in the 2027 dynamic budget). According to commenters, this lag could present a serious compliance challenge. Other commenters raised a concern in the opposite direction about the potential ''slack'' created by the lag time—meaning that as high-emitting units retire, their emissions and operation will still inform the state emissions budgets for additional years beyond their retirement due to the lag.

Response: The EPA recognizes there will be a data lag inherent in the computation of future year dynamic emissions budgets, because the dynamic budgets will reflect fleet composition and utilization data from recent previous control periods rather than the control periods for which the dynamic budgets are being calculated. This means that the resulting dynamic budgets will reflect a limited lag behind the actual pace of the EGU fleet's trends. However, on the whole, those trends are clearly toward more efficient and cleaner generating resources. Thus, the data lag on the whole will inure to the compliance benefit of EGUs by resulting in dynamic budgets that are generally calculated at levels likely to be somewhat higher than what a dynamic budget calculation reflecting real-time EGU operations would produce. The EPA believes this data lag is worthwhile to provide more compliance planning certainty and advance notice to affected EGUs of the dynamic budget applicable to an upcoming control period. Furthermore, this data lag in dynamic budget computation is comparable to the data lag of quantifying preset state budgets for 2023 through 2025 based upon 2021 data, and at no point in the long history of EPA's trading programs has such a data lag in state budget computation yielded any compliance problems for affected EGUs. Without dynamic budgeting, the data lag inherent in calculating preset budgets would grow unabated with the passage of time, as a fixed reference year of heat input levels would continually apply regardless of potentially higher heat input levels farther and farther into the future. By eliminating the increase in the length of the data lag, this new dynamic budgeting approach is a substantial improvement in performance of the program relative to previous approaches that were not capable of capturing changes over time in the fleet and its utilization beyond the scheduled changes known to the EPA at the time of establishing preset budgets.

The EPA disagrees that this lag will in fact pose compliance challenges for EGUs even if the unlikely scenario described by commenters were to occur. Several factors influence this. First, the change in methodology to preset budgets serving as a floor on budgets through 2029 means that the dynamic budget methodology can only produce an increase in the budget from this final rule through that year. Second, the adoption of a multi-year approach for identifying the heat input used to calculate the dynamic budgets will smooth the year-to-year budget changes and effectively eliminate the possibility of greatest concern, which was that a single year of unusually low heat input would be used to set the budget for a subsequent year that turned out to have unusually high heat input. While a year of unusually high heat input for a given state may still occur, the state's budgets for those years will never be based on heat input from an anomalously low year, but instead will always be based on an average of several years' heat input. Third, because the Group 3 trading program is an interstate program implemented over a wide geographic region, and it is unlikely that all regions of the country would uniformly experience a marked increase in fossil fuel heat input necessitating an additional supply of allowances, it is likely that allowances will be available for trade from one area of the country where there is less demand to another area where there is greater demand. Fourth, as explained in section VI.B.5 of this document, each state's assurance level will adjust to reflect actual heat input in that year. Specifically, the EPA will determine each state's variability limit for a given control period so that the percentage value used will be the higher of 21 percent or the percentage (if any) by which the total reported heat input of the state's affected EGUs in the control period exceeds the total reported heat input of the state's affected EGUs as reflected in the state's emissions budget for the control period. Thus, if in year 2030, for example, a state's actual heat input levels increase to a level that is not reflected in the dynamic budget calculation using earlier years of data, the assurance level (which absent the unusually high heat input would be 121 percent of the state's budget) will be calculated by the EPA following the 2030 ozone season, using that higher reported heat input. This will avoid imposing a three-for-one allowance surrender penalty on sources except where emissions exceed the assurance level even factoring in the increase in heat input in that year. Finally, as some commenters observed, the inherent data lag in dynamic budget quantification means that a state budget for the year 2030 will continue to reflect emissions from any EGU that retires before the 2030 control period but is still operating anytime during the 2026–2028 reference years from which the 2030 dynamic budget will be calculated. Given the likely ongoing trend of relatively high-emitting EGU retirements over time, this method for determining dynamic budgets should further assist the ability of remaining EGUs to obtain sufficient allowances to cover future heat input levels.

With respect to the comments expressing concern that dynamic budgets would create too much slack because of the lag in incorporating retirements, the EPA observes that dynamic budgets will yield a closer representation of Step 3 control stringency across the future fleet than preset budgets for years in which retirement plans are currently relatively unknown. Moreover, any risk that the lag would lead to an unacceptably large surplus of allowances is limited by EPA's finalization of the annual bank recalibration to 21 percent and 10.5 percent of the budget beginning in 2024 and 2030 respectively. The corresponding risk that a lag will lead sources to not operate emissions controls, due to a surplus of allowances, is also limited by the backstop daily emissions rates that start in 2024 (for sources with existing SCR controls) and no later than 2030 for other coal-fired sources.

Comment: Commenters allege that the dynamic budget methodology is effectively a ''one-way ratchet'' because, if EGUs pursue compliance strategies such as reduced utilization or generation shifting to comply with the rule rather than install or optimize pollution controls pursuant to the identified Step 3 emissions control strategies, the effect will be that the dynamic budget calculated in a future year will reflect that reduced heat input, but the applied emissions rate assumption will be the same. Thus, the approach according to commenters actually ''punishes'' sources for achievement of emissions reductions commensurate with EPA's Step 3 determinations through alternative compliance means, by producing a smaller budget in later years (less heat input multiplied by the same emissions rate). If the source again reduces utilization or shifts generation to comply with this budget, then budgets in later years will again ratchet down, and so on.

Response: First, the claims of dynamic budgeting being a one-way ratchet are incorrect. As pointed out at proposal, the dynamic budget process would allow for increased utilization to result in increased budgets. Moreover, this concern is entirely mooted for the period 2026 through 2029 with the shift to preset budgets serving as a floor; dynamic budgeting can only increase the budget used in any given year in this time period. Additionally, the use of a multi-year average heat input in the budget-setting calculations will, on the whole, modulate the dynamic budgets such that the budgets over time will only gradually change with changes in the operating profile of the EGU fleet.

For the control periods 2030 and later, this rule is premised on the expectation that all large coal-fired EGU sources identified for SCR-retrofit potential will, if they continue operating in 2030 or later, have installed the requisite post-combustion controls. Thus, the backstop daily emissions rate applies for all such sources beginning in the 2030 ozone season. In this latter period (post-2030), the EPA disagrees that the dynamic budget will punish fleet segments seeking to continue to pursue a strategy of reduced utilization. Rather, the dynamic budget will simply continue to reflect the Step 3 emissions control stringency. For instance, if there are two otherwise high-emitting sources in a state that can reduce emissions by operating SCR, this rule's control stringency finds it cost effective for both sources to operate their controls. If one source retires and is replaced by new lower-emitting generation, it is not a punishment to have the budgets adjust in a way that still incentivize remaining units to operate their controls. This is simply right-sizing the budget to an evolving fleet. It is a feature of the rule, not a flaw, and is designed to address observed instances in prior rules where market-driven reduced utilization resulted in non-binding (*i.e.,* overly slack) budgets and corresponding conditions where the incentive to operate a control dissipated over time. In the event that sources reduce utilization whether for compliance purposes or market-driven reasons, that also does not obviate the importance of continuing to incentivize the Step 3 emissions control stringency at identified sources.

c. Final Preset State Emissions Budgets

For affected EGUs in each covered state (and Indian country within the state's borders), this final rule establishes preset budgets for the control periods 2023 through 2029. For control periods 2026 through 2029, any of those preset budgets may be supplanted by the corresponding dynamic budget that will be tabulated at later date, if and only if that dynamic budget yields a higher amount. For 2030 and beyond, the dynamic budget formula promulgated in this rule will be applied to future year data to quantify state emissions budgets for those control periods. The procedures for allocating the allowances from each state budget among the units in each state (and Indian country within the state's borders) are described in section VI.B.9 of this document. The amounts of the final preset state emissions budgets for the 2023 through 2029 control periods are shown in Table VI.B.4.c–1.

TABLE VI.B.4.c–1—CSAPR NO_X OZONE SEASON GROUP 3 PRESET STATE EMISSIONS BUDGETS FOR THE 2023 THROUGH 2029 CONTROL PERIODS

[Tons] [a b]

State	Final emissions budgets for 2023	Final emissions budgets for 2024	Final emissions budgets for 2025	Preset emissions budgets for 2026	Preset emissions budgets for 2027	Preset emissions budgets for 2028	Preset emissions budgets for 2029
Alabama	6,379	6,489	6,489	6,339	6,236	6,236	5,105
Arkansas	8,927	8,927	8,927	6,365	4,031	4,031	3,582
Illinois	7,474	7,325	7,325	5,889	5,363	4,555	4,050
Indiana	12,440	11,413	11,413	8,410	8,135	7,280	5,808
Kentucky	13,601	12,999	12,472	10,190	7,908	7,837	7,392
Louisiana	9,363	9,363	9,107	6,370	3,792	3,792	3,639
Maryland	1,206	1,206	1,206	842	842	842	842
Michigan	10,727	10,275	10,275	6,743	5,691	5,691	4,656
Minnesota	5,504	4,058	4,058	4,058	2,905	2,905	2,578
Mississippi	6,210	5,058	5,037	3,484	2,084	1,752	1,752
Missouri	12,598	11,116	11,116	9,248	7,329	7,329	7,329
Nevada	2,368	2,589	2,545	1,142	1,113	1,113	880
New Jersey	773	773	773	773	773	773	773
New York	3,912	3,912	3,912	3,650	3,388	3,388	3,388
Ohio	9,110	7,929	7,929	7,929	7,929	6,911	6,409
Oklahoma	10,271	9,384	9,376	6,631	3,917	3,917	3,917
Pennsylvania	8,138	8,138	8,138	7,512	7,158	7,158	4,828
Texas	40,134	40,134	38,542	31,123	23,009	21,623	20,635
Utah	15,755	15,917	15,917	6,258	2,593	2,593	2,593
Virginia	3,143	2,756	2,756	2,565	2,373	2,373	1,951
West Virginia	13,791	11,958	11,958	10,818	9,678	9,678	9,678
Wisconsin	6,295	6,295	5,988	4,990	3,416	3,416	3,416

TABLE VI.B.4.c–1—CSAPR NO_X OZONE SEASON GROUP 3 PRESET STATE EMISSIONS BUDGETS FOR THE 2023 THROUGH 2029 CONTROL PERIODS—Continued

[Tons] [a b]

State	Final emissions budgets for 2023	Final emissions budgets for 2024	Final emissions budgets for 2025	Preset emissions budgets for 2026	Preset emissions budgets for 2027	Preset emissions budgets for 2028	Preset emissions budgets for 2029
Total	208,119	198,014	195,259	151,329	119,663	115,193	105,201

Table Notes:

[a] The state emissions budget calculations pertaining to Table VI.B.4.c–1 are described in greater detail in the Ozone Transport Policy Analysis Final Rule TSD. Budget calculations and underlying data are also available in Appendix A of that TSD.

[b] In the event this final rule becomes effective after May 1, 2023, the emissions budgets and assurance levels for the 2023 control period will be adjusted under the rule's transitional provisions to ensure that the increased stringency of the new budgets would apply only after the rule's effective date. The 2023 budget amounts shown in Table VI.B.4.c–1 do not reflect these possible adjustments. The transitional provisions are discussed in section VI.B.12 of this document.

5. Variability Limits and Assurance Levels

Like each of the other CSAPR trading programs, the Group 3 trading program includes assurance provisions designed to limit the total emissions from the sources in each state (and Indian country within the state's borders) in each control period to an amount close to the state's emissions budget for the control period, consistent with the principle that each state's sources must be held to the elimination of significant contribution within that state, while allowing some flexibility beyond the emissions budget to accommodate year-to-year operational variability beyond sources' reasonable ability to control. For each state, the assurance provisions establish an assurance level for each control period, defined as the sum of the state's emissions budget for the control period plus a variability limit, which under the Group 3 trading program regulations in effect before this rulemaking was 21 percent of the relevant state emissions budget. The purpose of the variability limit is to account for year-to-year variability in EGU operations, which can occur for a variety of reasons including changes in weather patterns, changes in electricity demand, and disruptions in electricity supply from other units or from the transmission grid. Because of the need to account for such variability in operations of each state's EGUs, the fact that emissions from the state's EGUs may exceed the state's emissions budget for a given control period is not treated as inconsistent with satisfaction of the state's good neighbor obligations as long as the total emissions from the EGUs remain below the state's assurance level. Emissions from a state's EGUs above the state's emissions budget but below the state's assurance level are treated in the same manner as emissions below the state's emissions budget in that such emissions are subject to the same requirement to surrender allowances at a ratio of one allowance per ton of emissions. In contrast, emissions above the state's assurance level for a given control period are strongly discouraged as inconsistent with the state's good neighbor obligations and are subject to an overall 3-for-1 allowance surrender ratio. The establishment of assurance levels with associated extra allowance surrender requirements was intended to respond to the D.C. Circuit's holding in *North Carolina* requiring the EPA to ensure within the context of an interstate trading program that sources in each state are required to address their good neighbor obligations within the state and may not simply shift those obligations to other states by failing to reduce their own emissions and instead surrendering surplus allowances purchased from sources in other states.[319]

In this rulemaking, the EPA did not propose and is not making changes to the basic structure of the Group 3 trading program's assurance provisions, which will continue to set an assurance level for each control period equal to the state's emissions budget for the control period plus a variability limit and will continue to apply a 3-for-1 surrender ratio to emissions exceeding the state's assurance level.[320] Each assurance level also will continue to apply to the collective emissions of all units within the state and Indian country within the state's borders.[321] However, the EPA is making a change to the methodology for determining the variability limits. Specifically, the EPA will determine each state's variability limit for a given control period so that, instead of always multiplying the state's emissions budget for the control period by a value of 21 percent, the percentage value used will be the higher of 21 percent or the percentage (if any) by which the total reported heat input of the state's affected EGUs in the control period exceeds the total historical heat input of the state's affected EGUs as reflected in the state's emissions budget for the control period. For example, if the total reported heat input of the state's covered sources for the 2025 control period is 130 percent of the historical heat input used in computing the state's 2025 budget, then the state's variability limit for the 2025 control period will be 30 percent of the state's emissions budget instead of 21 percent of the state's emissions budget. The EPA expects that the minimum 21 percent will apply in almost all instances, and that the alternative, higher percentage value will apply only in control periods where operational variability causes an unusually large increase relative to the historical data used in setting the state's emissions budget, which would be a situation meriting a temporarily higher variability limit and assurance level. The revised methodology for determining the variability limits will apply both with respect to control periods when a state's emissions budget is a preset budget established in this final rule and with respect to control periods when a state's emissions budget is a dynamically-determined budget computed using the procedures laid out in the regulations, and it will apply starting with the 2023 control period rather than starting with the 2025 control period as proposed.

The purpose of the revision to the variability limits is to better align the variability limits for successive control periods with the heat input data used in setting the state emissions budgets. Under the final rule, each dynamically

[319] 531 F.3d at 908.

[320] As discussed in section VI.B.8, the EPA is also establishing a new secondary emissions limitation for individual units that will apply in situations where an exceedance of the relevant state's assurance level has occurred.

[321] *See* 40 CFR 97.1002 (definitions of ''common designated representative,'' ''common designated representative's assurance level'' and ''common designated representative's share''), 97.1006(c)(2), and 97.1025.

determined emissions budget will be computed using the latest available reported heat input, which for each budget set for a control period in 2026 or a later year will be the average state-level heat input for the control periods two, three, and four years before the control period whose budget is being determined (for example, the dynamic state emissions budgets for the 2026 control period will be computed in early 2025 using the reported state-level heat input for the 2022–2024 control periods). The revised variability limits will be well coordinated with the budgets established using this dynamic budgeting process, because the percentage change in the actual heat input for the control period relative to the earlier multi-year average heat input used in computing the state's emissions budget will be an appropriate measure of the degree of operational variability actually experienced by the state's EGUs in the control period relative to the assumed operating conditions reflected in the state's budget. Setting a variability limit in this manner is thus entirely consistent with the overall purpose of including variability limits in the assurance provisions.

As discussed in sections VI.B.1.b.i and VI.B.4, for the 2023–2025 control periods the state emissions budget for a given control period will be the preset budget determined in this rule, and for the 2026–2029 control periods, the state emissions budget for a given control period will be the preset budget determined in this rule rather than the dynamically determined budget computed in the year before the control period unless the dynamic budget is higher than the preset budget. If the state emissions budget is the preset budget, the historical heat input data reflected in that budget will be the heat input data for the 2021 control period, adjusted to reflect projected changes in fleet composition over time that are known at the time of this rulemaking, but not adjusted to reflect changes in fleet composition that are not known at the time of the rulemaking or changes in the utilization of individual units.[322] In this case, the variability limit for the control period would be the higher of 21 percent or the percentage change in the actual heat input for the control period relative to the heat input for the 2021 control period as adjusted to reflect the projected changes in fleet composition. The EPA believes it is reasonable to apply the same principle in setting the variability limit in control periods where the preset floor budgets are used as in control periods where the dynamically determined budgets are used, because the preset floor budgets are computed using the same principles as the dynamically determined budgets, with the major difference being that the available heat input data used in computing the preset budgets are necessarily less current. Accordingly, because preset budgets established in this manner are used starting with the 2023 control period, the EPA believes it is also reasonable to begin implementing the revised methodology for determining variability limits starting with the 2023 control period.

The reason the EPA is using the higher of a fixed 21 percent or the percentage change in heat input computed as just described is that the EPA believes that, for operational planning purposes, it can be useful for sources to know in advance of the control period a minimum value for what the variability limit could turn out to be. Because a state's actual total heat input for a control period is not known until after the end of the control period, this revision will have the consequence that the state's final variability limit and assurance level for the control period also will not be known until after the control period. However, because the rule provides that the variability limit will always be at least 21 percent, the sources in a state will be able to rely for planning purposes on the knowledge that the assurance level will always be at least 121 percent of the state's emissions budget for the control period. Advance knowledge of the minimum possible amount of the assurance level can be useful to sources, because one way a fleet owner can be confident that it will never incur the 3-for-1 allowance surrender ratio owed for emissions exceeding its state's assurance level is to plan its operations so as to never allow the emissions from its fleet to exceed the fleet's aggregated share of the state's assurance level for the control period. Knowing that the variability limit will always be at least 21 percent will provide sources with minimum values they could use for such planning purposes.

The EPA believes that 21 percent is a reasonable value to use as the minimum variability limit. To determine appropriate variability limits for the trading programs established in CSAPR, the EPA analyzed historical state-level heat input variability over the period from 2000 through 2010 as a proxy for emissions variability, assuming constant emissions rates. *See* 76 FR 48265. Based on that analysis, the variability limits for ozone season NO_X in both CSAPR and the CSAPR Update were set at 21 percent of each state's budget, and these variability limits for the NO_X ozone season trading programs were then codified in 40 CFR 97.510 and 97.810, along with the respective state budgets.[323] For the Revised CSAPR Update, the EPA performed an updated variability analysis for the twelve states being moved into the Group 3 trading program in that rulemaking, evaluating historical state-level heat input variability over the period from 2000 through 2019. The updated analysis again resulted in a variability estimate of 21 percent. The EPA also considered shorter time periods for the updated analysis and found that the resulting variability estimates were not especially sensitive to the particular time period analyzed.[324] A further updated analysis for this rulemaking again results in a variability estimate of 21 percent for most states, and although the historical analysis indicates a higher percentage for the covered state with the smallest total heat input figures in this analysis—New Jersey—the EPA does not consider it appropriate to raise the minimum variability limit percentage beyond 21 percent for all other covered states based on the analytic results for one state, where small absolute heat input figures have resulted in a larger variability percentage.[325] (Moreover, because of the provision allowing a state's variability limit for a given control period to be higher than 21 percent if the state's actual heat input exceeds the heat input used to set the state's emissions budget by more than 21 percent, there is no need to set a minimum variability limit higher than 21 percent specifically for New Jersey.) Based on the consistent conclusions of these multiple analyses, the EPA is continuing to use 21 percent as the

[322] The total heat input amount used in computing each state's preset emissions budget for each control period from 2023 through 2029 is included in Appendix A of the Ozone Transport Policy Analysis Final Rule TSD at column I of the ''State 2023''–''State 2029'' worksheets.

[323] Briefly, the 21 percent variability limit was determined in the analysis by identifying, for all the states in the region covered by the ozone season NO_X trading program, and at a 95 percent confidence level, the maximum expected deviation in any state's total heat input for any single control period in the data sample from that state's trend-adjusted mean total heat input for all the control periods in the data sample. For details on the original variability analysis for 26 states over the 2000–2010 period, including a description of the methodology, see the Power Sector Variability Final Rule TSD from the CSAPR (EPA–HQ–OAR–2009–0491–4454), available in the docket for this rule.

[324] For the updated variability analysis for twelve states for the 2000–2019 period, *see* the Excel file ''Historical Variability in Heat Input 2000 to 2019.xls'', available in the docket for this rule.

[325] *See* the Excel document, ''OS Heat Input—Variability 2000 to 2021.xls'' for updated data, application of the CSAPR variability methodology, and results applied to heat input for 2000 through 2021 for all states and for the region collectively.

minimum value in the revised approach for establishing variability limits for all control periods under this rule.

The provisions of the final rule relating to assurance levels and variability limits are unchanged from proposal, with the exception that the provision establishing a higher variability limit for a state in a given control period where the state's actual heat input exceeds the heat input used in computing the state emissions budget for that control period by more than 21 percent will be implemented starting with the 2023 control period instead of the 2025 control period.

Comment: Some commenters supported the EPA's proposal to raise a state's variability limit above 21 percent for a given control period if the state's actual heat input for the control period was more than 121 percent of the historical heat input used to set the state's budget for that control period. These commenters agreed with the EPA that making this adjustment is consistent with the assurance provisions' purpose of strongly incentivizing each state to achieve its required emissions reductions within the state while also accounting for year-to-year variability in electric system operations.

One commenter stated that the EPA should not finalize the proposed revision to the variability limit provisions, claiming that by allowing sources in some states to increase utilization and heat input so as to exceed the state's budget by more than 21 percent in a given year, the adjustment would then cause the state's subsequent dynamically determined budgets to be higher, allowing greater emissions over time.

Response: The EPA disagrees with the comment advocating against finalization of the proposed change to the variability limit provisions. The Agency continues to view the proposed change as useful for accommodating instances where, because of electrical system operating needs, a state's actual total heat input in a control period exceeds the historical heat input used to set the state emissions budget for the control period, potentially causing increased emissions even when all EGUs in a state are achieving emissions rates consistent with the Step 3 emissions control stringency. Moreover, the EPA does not believe that the provision would lead to higher overall program-wide budgets. No extra allowances would be created by the increase in a state's variability limit, so with or without the adjustment, any allowances to cover the emissions in excess of the state's budget would still need to be obtained through acquisition of allowances issued to sources in other states or the use of banked allowances. Thus, to the extent that the change in the variability limit provisions facilitates shifting of generation from some states to other states, increased heat input in the first set of states would generally be offset by decreased heat input in the second set of states, such that any increases in future dynamic budgets for the first set of states would be offset by decreases in future dynamic budgets for the second set of states. In addition, the final rule's use of multiple years of historical heat input data to compute the dynamically-determined state budgets will moderate the effect of any single year's heat input on the dynamically-determined budgets for future control periods.

6. Annual Recalibration of Allowance Bank

As discussed in section VI.B.1.b of this document, the EPA is making two revisions to the Group 3 trading program designed to better maintain the Step 3 emissions control stringency over time. The first proposed revision, discussed in section VI.B.4 of this document, is to adopt a dynamic budget-setting methodology that will allow state emissions budgets in future years to reflect more accurate information about the composition and utilization of the EGU fleet. The second, complementary, revision is to recalibrate the bank of unused allowances each control period to prevent allowance surpluses from accumulating and adversely impacting the ability of the trading program in future control periods to maintain the Step 3 emissions control stringency.

As proposed and now finalized in this rule, the bank recalibration process will start with the 2024 control period, after the compliance process for the 2023 control period for all current and newly added states in the Group 3 trading program has been completed. The recalibration process for each control period will be carried out on or shortly after August 1 of that control period, two months after the compliance deadline for the previous control period, making the date of the first recalibration August 1, 2024. The recalibrations take place on August 1 each year because compliance for the previous control period would not be completed until after June 1. However, because data on the amounts of allowances held are publicly available and the total quantity of allowances needed for compliance for the previous control period will be known shortly after the end of that control period, sources and other market participants will be able to ascertain with reasonable accuracy shortly after the end of each control period what degree of recalibration to expect for the next control period, even if the recalibration would not actually be carried out until the following August. The EPA will make an estimate of the applicable calibration ratio for each control period publicly available no later than March 1 of the year of the control period for which the bank will be recalibrated.

Before undertaking a recalibration process each control period, the EPA will first determine whether the total amount of all banked Group 3 allowances from previous control periods held in all facility accounts and general accounts in the Allowance Management System exceeds the target bank amount. (For this purpose, no distinction will be made between banked Group 3 allowances issued from the state emissions budgets for previous control periods and banked Group 3 allowances issued through the conversion of previously banked Group 2 allowances.) If the total amount of banked Group 3 allowances does not exceed the target bank amount, the EPA will not carry out any recalibration for that control period. If the total amount of unused allowances does exceed the target bank amount, the EPA will determine for each account with holdings of banked Group 3 allowances the account-specific recalibrated amount of allowances, computed as the account's total holdings of banked Group 3 allowances immediately before the recalibration multiplied by the target bank amount and divided by the total amount of banked Group 3 allowances in all accounts, rounded up to the nearest allowance. Finally, the EPA will deduct from each account any banked Group 3 allowances exceeding the account's recalibrated amount of banked allowances.

As the target bank amount used in the recalibration process for each control period, the EPA will use an amount determined as a percentage of the sum of the state emissions budgets for the control period. For the control periods from 2024 through 2029, the target percentage will be 21 percent, which is the sum of the states' minimum variability limits.[326] For control periods in 2030 and later years, the target percentage will be 10.5 percent, or half of the sum of the states' minimum

[326] As discussed in section VI.B.5, an individual state's variability limit can be higher than 21 percent in a given control period if the state's actual heat input for that control period is more than 121 percent of the historical heat input used in computing the state emissions budget for the control period.

variability limits. In the proposal, the EPA cited two reasons for proposing the 10.5 percentage amount. First, in the transition from CSAPR to the CSAPR Update, where the EPA set a target bank amount 1.5 times the sum of the variability limits, and in the transition from the CSAPR Update to the Revised CSAPR Update, where the EPA set a target bank amount of 1.0 times the sum of the variability limits, in each case the initial bank proved larger than necessary, as total emissions of all sources in the program were less than the budgets. Second, an analysis of year-to-year variability of heat input for the region covered by this rule suggests that the regional heat input for an individual year can be expected to vary by up to 10.5 percent above or below the central trend with 95 percent confidence. This variability analysis is an application to the entire region of the variability analysis EPA has performed for individual states to establish the minimum variability limit of 21 percent for the states in the trading program.[327] When the analysis is performed at the regional level, the data show less year-to-year variation than when the analysis is performed at the individual state level. Within the trading program structure, it is reasonable to use variability analyzed at the level of individual states to set the variability limits, which apply at the level of individual states, while using variability analyzed at the level of the overall region to set a target level for a bank, which will apply at the level of the overall program.

In the final rule, in response to comments, the EPA has determined to maintain the 10.5 target percentage for the reasons discussed in previous paragraphs, but to defer application of this target percentage until the 2030 control period. For the control periods from 2024 through 2029, the EPA will instead use a target percentage of 21 percent. The reason for using a higher target percentage for the 2024–2029 control periods is to provide additional support for allowance market liquidity during these years, which both the EPA and commenters view as an important period of generating fleet transition for the power industry.

The annual bank recalibrations, at either ratio, are an important enhancement to the trading program that will help maintain the control stringency determined to be necessary to address states' good neighbor obligations for the 2015 ozone NAAQS over time. Moreover, the recalibrations are less complex than alternative approaches would be. For example, the NO_X Budget Trading Program established in the NO_X SIP Call also contained provisions designed to prevent excessive accumulations of banked allowances on program stringency, but those provisions—under the name ''progressive flow control''—introduced uncertainty as to whether banked allowances would be usable to offset one ton of emissions or less than one ton of emissions in the current control period. As a consequence of this uncertainty, in some control periods, allowances banked from earlier control periods traded at lower prices than allowances issued for the current control period.[328] The EPA considers the recalibration mechanism established in this rule to be simpler with less associated uncertainty. Following each bank recalibration, all allowances usable for compliance in the control period will have known, equal compliance values for the remainder of the control period and until the deadline for surrendering allowances after the control period.

Finally, the EPA observes that the recalibration mechanism is entirely consistent with the Agency's existing authority under 40 CFR 97.1006(c)(6) to ''terminate or limit the use and duration'' of any Group 3 allowance ''to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.'' The Administrator is determining that the recalibrations are both necessary and appropriate to ensure that the control stringency selected in this rulemaking is maintained and states' good neighbor obligations with respect to the 2015 ozone NAAQS are addressed. The recalibration process will complement the revised budget-setting process by preventing any surplus of allowances created in one control period from diminishing the intended stringency and resulting emissions reductions of the emissions budgets for subsequent control periods. For further discussion of the reasons for bank recalibration, see section VI.B.1.b.ii of this document.

The bank recalibration mechanism finalized in this rule is unchanged from the proposal except for the final rule's adoption of a target percentage of 21 percent rather than 10.5 percent for the control periods from 2024 through 2029. The EPA's responses to comments on the bank recalibration mechanism are discussed in the remainder or this section and in section 5 of the *RTC* document. Further discussion of the reasons for adopting a higher target percentage for the 2024–2029 control periods is included in section VI.B.1.d of this document.

Comment: Some commenters acknowledged the EPA's authority to manage the quantities of allowances carried over from one control period to the next as banked allowances, including some commenters who as a policy matter did not support such an approach. Other commenters claimed that any removal from the program of allowances banked in earlier control periods would constitute an unlawful taking of property or would constitute unlawful overcontrol.

Response: The EPA disagrees with comments contending that the proposed bank recalibration provisions would be unlawful, either as asserted takings of property or as over-control for purposes of the Good Neighbor provision. With respect to the claim that removing allowances would constitute takings of property, the commenters misconstrue the nature of an allowance. The allowances used in the Group 3 trading program are created under the program's regulations, which expressly provide that the allowances are not property rights but are limited authorizations to emit NO_X in accordance with the provisions of the Group 3 trading program.[329] These provisions of the Group 3 trading program regulations have been in existence since the Revised CSAPR Update and were not reopened in this action. This approach of creating limited authorizations to engage in particular forms of conduct within a regulatory program extends back to the Acid Rain Program, where the approach was mandated by Congress, and has been followed by EPA in each subsequent allowance trading program for the electric power sector.[330] Moreover, as noted earlier in this section, the Group 3 trading program regulations provide the EPA

[327] See the Power Sector Variability Final Rule TSD from CSAPR, available at *https://www.epa.gov/csapr/power-sector-variability-final-rule-tsd* for a description of the methodology. Also see the Excel document ''OS Heat Input—Variability 2000 to 2021.xls'' for updated data, application of the CSAPR variability methodology, and results applied to heat input for 2000 through 2021 for all states and for the region collectively.

[328] For more discussion of the progressive flow control mechanism, as well as allowance price data showing a discounted value for banked allowances, see ''NO_X Budget Trading Program: 2005 Program Compliance and Environmental Results'' (September 2006) at 28–30, *https://www.epa.gov/sites/default/files/2015-08/documents/2005-nbp-compliance-report.pdf*.

[329] 40 CFR 97.1006(c)(6)–(7).

[330] *See, e.g.,* 42 U.S.C. 7651b(f) and 40 CFR 72.9(c)(6)–(7) (Acid Rain Program example); 40 CFR 97.6(c)(6)–(7) (Federal NO_X Budget Trading Program example); 40 CFR 97.106(c)(5)–(6) (CAIR NO_X Annual Trading Program example).

Administrator with the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act, and the Administrator is making such a determination in this rule.

The EPA also disagrees that bank recalibration would constitute overcontrol. The emissions that are permissible in a given control period consistent with the Step 3 control stringency are quantified in the state emissions budgets for the control period. Banked allowances from previous control periods are necessarily surplus to the state emissions budgets for the current control period. As noted in section VI.B.1, in an allowance trading program, banking provisions can serve several useful purposes, including continuously incentivizing sources to reduce their emissions even when they already hold sufficient allowances to cover their expected emissions for a control period, facilitating compliance cost minimization, accommodating necessary operational flexibility, and promoting allowance market liquidity. However, these useful purposes do *not* include allowing sources to plan to emit in excess of the Step 3 control stringency as represented by the state emissions budgets for the control period. Accordingly, in the overcontrol analysis discussed in section V.D.4, the EPA analyzed whether the emissions reductions necessary to meet the state emissions budgets without relying for compliance purposes on any allowances banked in earlier control periods would result in overcontrol and determined there would be no overcontrol. (That is, the modeling of the effects of the Group 3 emissions budgets in 2026 did not include an assumption that there would be any banked allowances.) Thus, even if the Agency had finalized regulatory provisions removing *all* banked allowances from the trading program between control periods—in contrast to the actual bank recalibration provisions, which permit substantial quantities of banked allowances to remain in the trading program—the information available to the Agency suggests such provisions would not constitute over-control. With respect to some commenters' assertions that bank recalibration would over-control by ''writing off'' emission reductions that may have gone beyond the reductions necessary to address the Good Neighbor provision or would make it more difficult to create surplus allowances in one control period to offset excess emissions in later control periods, EPA notes that the NAAQS apply continuously, and the possibility that the sources in a state may have done more than the minimum necessary to meet the state's Good Neighbor obligations in one control period does not create a right for the state to do less than is necessary to meet the state's Good Neighbor obligations in subsequent control periods.

Comment: Some commenters expressed concern that excessive quantities of banked allowances, like excessive quantities of budgeted allowances, can lead to lower allowance prices. The commenters observed that with lower allowance prices, some units would likely operate their controls less effectively, resulting in a greater likelihood that the emissions stringency found necessary in this rule would not be sustained. Other commenters expressed the view that other provisions of the rule, including more stringent state emissions budgets, the backstop daily NO_X emissions rate provisions, and the assurance provisions would be sufficient to incentivize EGUs to operate their controls effectively, making allowance bank recalibration superfluous for this purpose.

Response: The EPA agrees with the comments explaining that without bank recalibration, the quantities of banked allowances can grow, leading to lower allowance prices, diminished incentives for sources to optimize control operation, and greater risk of failure to sustain the Step 3 control stringency, and disagrees with the comments arguing that other rule provisions would make bank recalibration unnecessary. The suggestion that the assurance provisions can maintain program stringency regardless of allowance quantities ignores the fact that the emission levels consistent with the Group 3 control stringency in a given control period are the state emissions budgets, not the higher assurance levels. If the quantities of banked allowances in the program grow to the point where sources collectively can plan to emit above the collective state emissions budgets, then the trading program would be unable to ensure that the Group 3 control stringency is being achieved, even if emissions do not rise further than the assurance levels. Further, there are now examples from the Group 2 trading program of sources emitting in excess of the state-wide assurance levels, because a glut of banked allowances which was not prevented by the regulations for that trading program rendered even the three-to-one surrender ratio ineffective. Suggestions that the backstop emissions rate provisions can maintain program stringency regardless of the quantities of banked allowances are similarly mistaken, because rather than reducing overall emissions of all sources in the trading program, the backstop rate provisions are designed to ensure that the largest individual sources of potential emissions operate their controls consistently. If the quantities of banked allowances are allowed to grow to the point where sources collectively can plan to emit above the collective state emissions budgets, the backstop rate provisions would do nothing to constrain emissions from the sources not subject to the backstop rate.

With respect to the suggestion that state emissions budgets reflecting sufficient control stringency can avoid the need for bank recalibration, the EPA observes that the budget-setting and bank recalibration provisions in this rule are complements, not substitutes. If in a given year sources collectively emit against the collective state emissions budgets such that the ending allowance bank—that is, the allowances remaining after deduction of the allowances required for compliance—is less than the bank target amount, then the bank will not be recalibrated for the following control period. However, in the event that sources collectively emit against the collective state emissions budgets such that the ending allowance bank is above the bank target amount, then the recalibration provisions will ensure that the recalibrated allowance bank does not introduce an excessive overall quantity of allowances into the trading program for the following control period when combined with the state emissions budgets calculated for that control period. Without the recalibration provisions, the trading program would lack any mechanism for removing excess allowances that are inconsistent with maintaining the Step 3 emissions control stringency which the Step 4 trading program is designed to implement.

Comment: Some commenters claimed that the recalibration process itself would have undesirable consequences. First, some said that because bank recalibration would be executed partway through the control period, it would introduce uncertainty concerning the quantities of allowances each source would have available, impeding efforts to plan. Second, some commenters claimed that the prospect of bank recalibration would create counterproductive incentives for allowance holders. According to the commenters, allowances holders would be incentivized to ''use or lose'' their allowances (to reduce the number of allowances that would be removed from their accounts in the recalibration process), thereby causing increased emissions, or alternatively would be incentivized to refuse to sell allowances (to allow the holders to have more allowances after the next recalibration), thereby reducing allowance market liquidity.

Response: The EPA disagrees with these comments. As discussed previously in this section, the recalibration process has been scheduled for August 1 of each control period because compliance for the previous control period (and the associated allowance trading activities) would not be completed until after June 1. However, the information needed to project the degree of recalibration will be available by early November of the previous year, and the EPA will make an estimate publicly available no later than March 1, two months before the start of the control period. Further, at least 80 percent of the allowances for use in a given control period will be the allowances allocated from the state emissions budgets (with the recalibrated banked allowances from the prior control period comprising the remainder), and the emissions budgets and unit-level allocations amounts will be known approximately a year before the start of the control period.

The comments claiming that the introduction of a bank recalibration process would create incentives to ''use or lose'' allowances or to hoard allowances are not persuasive. By reducing the supply of allowances carried over from previous control periods, bank recalibration would tend to raise the price of allowances in the current control period, making it more cost-effective and therefore in sources' interest to further reduce their emissions than to increase their emissions. Higher allowance prices would also increase the cost of hoarding allowances just as higher fuel prices raise the cost of maintaining large fuel inventories. Moreover, the EPA expects that the prospect of having banked allowances recalibrated after the end of the control period is much more likely to *discourage* hoarding than to encourage it. Given the choice between holding an allowance which may be removed as part of an upcoming recalibration process or instead selling the allowance for cash, the sale option will become more attractive. By creating a ''sell or lose'' incentive for holders of surplus allowances, the recalibration process should increase allowance market liquidity. At the same time, by ensuring a banked allowance will always have some value for use in a future control period, the bank recalibration mechanism in this program will continue to incentivize early emissions reductions.

Comment: Turning to the level of the bank recalibration target, some commenters objected to the target bank percentage of 10.5 percent, saying that a larger bank would be needed to ensure that sufficient allowances would be available to enable sources to run as needed to provide reliable electricity service, particularly with the large year-to-year swings in budgets that the commenters anticipated could occur with dynamic budgets computed using a single rolling historical year and with anticipated growth in renewable generation. Some commenters recommended a target bank percentage of 21 percent. Some commenters stated that even if the overall quantity of allowances available for use was greater than the total amount of emissions, a larger bank of allowances would facilitate trading and promote greater allowance market liquidity, citing reports of high allowance prices in 2022.

Response: As discussed in sections VI.B.1.d and VI.B.4 and earlier in this section, the EPA does not agree with comments suggesting that annual bank recalibration in itself poses a risk to electric grid reliability. Nevertheless, the Agency has made several changes from proposal in the final rule designed to address concerns expressed about reliability by increasing compliance flexibility through the 2029 control period. These changes through the 2029 control period include the use of a target bank percentage of 21 percent and the promulgation of preset budgets that will serve as the state emissions budgets unless the dynamic budgets for the control periods are higher. In addition, to reduce year-to-year variability under the budget-setting methodology, dynamic budgets will be calculated using multiple years of historical heat input data instead of heat input data from a single year. The EPA views these changes as responsive to the principal reasons that commenters gave for their claims that the target bank percentage should be higher than 10.5 percent. Regarding the claim that a higher target bank percentage is needed because increased renewable generation makes the demand for fossil generation more variable, commenters did not provide evidence demonstrating that the overall quantities of fossil generation throughout the multi-state region covered by this rule—as opposed to the operating patterns of some individual units—are becoming more variable, and the Agency declines to make an adjustment for such a reason at this time.

With respect to the comments advocating for an even higher bank target percentage to facilitate trading and promote market liquidity, the Agency observes that any such advantage of larger allowance banks must be balanced with the disadvantages of excess allowance supply—specifically, reduced allowance prices, diminished incentives for sources to optimize control operation, and greater risk of failure to sustain the Step 3 control stringency. In the final rule, the EPA finds that a reasonable balance between these opposing considerations is struck by temporarily adopting a higher bank target percentage of 21 percent (consistent with the initial bank targets used in this rule and previous rules) and deferring implementation of the 10.5 percent target bank percentage identified by the Agency's analysis as a sustainable percentage in the longer term until the 2030 control period.

7. Unit-Specific Backstop Daily Emissions Rates

While the identified EGU emissions reductions in section V of this document (*i.e.,* the Step 3 emissions control stringency) are incentivized and secured primarily through the corresponding seasonal state emissions budgets (expressed as a seasonal tonnage limit for all covered EGUs within a state's borders) described earlier, the EPA is also incorporating a backstop daily emissions rate of 0.14 lb/mmBtu applied to coal-fired steam units serving generators with nameplate capacity greater than or equal to 100 MW in covered states, except circulating fluidized bed units. This is important for ensuring the elimination of significant contribution on a more consistent basis from the relevant sources and over each day of the ozone season.

Starting with the 2024 control period, a 3-for-1 allowance surrender ratio (instead of the usual 1-for-1 surrender ratio) will apply to emissions during the ozone season from any large coal-fired EGU with existing SCR controls exceeding by more than 50 tons a daily average NO_X emissions rate of 0.14 lb/mmBtu. The daily average emissions rate provisions will apply to large coal-fired EGUs without existing SCR controls (except circulating fluidized bed units) starting with the second control period in which newly installed SCR controls are operational at the unit, but not later than the 2030 control period. See Appendix A of the Ozone Transport Policy Analysis Final Rule

TSD for a list of coal-fired steam units serving generators larger than or equal to 100 MW in covered states for which the identified backstop emissions rate will apply.

For each unit subject to the backstop daily emissions rate provisions for a given control period, the amount of emissions subject to the 3-for-1 surrender ratio will be determined as follows, generally on an automated basis using the unit's data acquisition and handling system (DAHS) required under 40 CFR part 75. For each day of the control period where the unit's average emissions rate for that day was higher than 0.14 lb/mmBtu, the owner or operator will compute what the unit's reported emissions on that day would have been (given the unit's reported heat input for the day) at an emissions rate of 0.14 lb/mmBtu. The difference between the unit's emissions for the day as actually reported and the emissions that would have been reported if the unit's emissions rate was 0.14 lb/mmBtu is the unit's daily exceedance. The amount of emissions subject to the 3-for-1 surrender ratio for the control period is the sum of the unit's daily exceedances for all days of the control period minus 50 tons (but not less than zero).[331] All calculations will rely on the data monitored and reported for the unit in accordance with 40 CFR part 75.

The EGU NO_X Mitigation Strategies Final Rule TSD describes the methodology for deriving the 0.14 lb/mmBtu daily rate limit in more detail. The methodology is summarized as follows. First, consistent with stakeholders' focus on providing daily assurance of control operation, which is consistent with the 8-hour form of the 2015 ozone NAAQS and the tendency for ozone levels to spike on a diurnal cycle, the EPA determined that daily (as opposed to hourly or monthly) was an appropriate time metric for backstop emissions rate limits instituted to ensure operation of controls on high ozone days. The EPA derived the 0.14 lb/mmBtu daily rate limit by determining the particular level of a daily rate that would be comparable in stringency to the 0.08 lb/mmBtu seasonal emissions rate that the Agency has identified as reflecting SCR optimization at existing units.[332] The EPA first conducted an empirical exercise using reported daily emissions rate data from existing, SCR-controlled coal units that were emitting at or below 0.08 lb/mmBtu on a seasonal average basis. This seasonal rate reflects the average across a unit's range of varying daily rates reflecting different operation conditions. When the EPA examined the daily emissions rate pattern for these units considered to be optimizing their SCRs on a seasonal basis, the EPA observed that over 95 percent of the time, their daily rates were below 0.14 lb/mmBtu. In addition, for these units, less than 1 percent of their seasonal emissions would exceed this daily rate limit.

The EPA conducted this analysis to be consistent with the methodology developed in the 2014 1-hr SO_2 attainment area guidance for identifying ''comparably stringent'' emissions rates over varying time-periods.[333] Appendix C of that guidance describes a series of steps that involve: (1) compiling emissions data to reflect a distribution of emissions rates with various averaging times, (2) determining the 99th percentile of the average emissions values compiled in the previous step, and then (3) applying ''adjustment factors'' or ratios of the 99th percentile values to emissions rates to convert them (usually from a short-term rate to a longer-term rate). In this case, the EPA applied the methodology in reverse to convert a longer-term limit (the seasonal rate of 0.08 lb/mmBtu which was assumed to be equivalent to a 30-day rate of 0.08 lb/mmBtu for purposes of this comparison of rates across averaging times) to a comparably stringent short-term limit (a daily rate of 0.14 lb/mmBtu).

The inclusion of a 50-ton threshold for emissions exceeding the backstop daily emissions rate before the 3-for-1 surrender applies is a change from the proposal. As discussed in section VI.B.1.d of this document, the EPA made this change in response to comments concerning the possibility that the 3-for-1 surrender ratio could otherwise have applied to emissions outside an EGU operator's control, with the most important example being the emissions during unit startup before SCR equipment can be brought into service, and to a lesser extent the emissions during unit shutdown. The analysis used by the EPA to derive the 50-ton threshold is described in detail in the Ozone Transport Policy Analysis Final Rule TSD. Briefly, for a set of 164 SCR-equipped units with seasonal average NO_X emissions rates at or below 0.08 lb/mmBtu in 2021, the EPA evaluated the total amounts of emissions that would have been determined to exceed a daily average emissions rate of 0.14 lb/mmBtu in the 2021 and 2022 ozone seasons. In the 2021 ozone season, only 572 tons out of these units' total emissions of 60,350 tons, or 0.9 percent, would have been considered exceedances, with an average exceedance per unit of less than 4 tons. The highest amount for any of the 164 individual units in either ozone season was 48 tons. Based on this analysis, the EPA concludes that adding a 50-ton threshold to the backstop daily emissions rate provisions will ensure that substantially all emissions outside the control of an SCR-equipped unit's operator will not be subject to the 3-for-1 surrender ratio. Because there is no reason to expect the range of emissions during conditions when SCR controls cannot be operated to differ between SCR-equipped units and units without SCR, inclusion of the 50-ton threshold effectively prevents application of the 3-for-1 ratio to emissions during startup and shutdown by units without SCR as well.

At the same time, the EPA believes the 50-ton threshold is not large enough to eliminate the intended incentive to achieve emissions rates consistent with good SCR performance under conditions other than startup and shutdown. For a set of 124 SCR-equipped units with seasonal average NO_X emissions rates above 0.08 lb/mmBtu, the total amount of emissions exceeding a daily average emissions rate of 0.14 lb/mmBtu in the 2021 ozone season was 18,629 tons. Of this total amount, 15,374 tons would have been in excess of the 50-ton thresholds for the various units, indicating that even after application of the threshold, the 3-for-1 surrender ratio would have applied to over 80 percent of the daily exceedance amounts.

The backstop daily NO_X emissions rate provisions finalized in this rule are unchanged from the proposal except for the inclusion of a 50-ton threshold for emissions exceeding the backstop emissions rate before the 3-for-1 surrender ratio applies and the deferral of the application of the provisions to units without existing SCR controls

[331] In the regulatory text at 40 CFR 97.1024 defining the total quantity of allowances that must be surrendered for a source's emissions in a control period, these amounts of emissions for all the units at the source are subject to a requirement to surrender two extra allowances per ton in addition to the usual 1-for-1 allowance surrender requirement, yielding a total surrender ratio of 3-for-1 for emissions over the 50-ton threshold.

[332] *See* page 24 of ''Guidance for 1-hour SO_2 Nonattainment Area SIP Submission'' at *https://www.epa.gov/sites/default/files/2016-06/documents/20140423guidance_nonattainment_sip.pdf.* ''A limit based on the 30-day average of emissions, for example, at a particular level is likely to be a less stringent limit than a 1-hour limit at the same level 1 since the control level needed to meet a 1-hour limit every hour is likely to be greater than the control level needed to achieve the same limit on a 30-day average basis.''

[333] *See* Guidance for 1-Hour SO_2 Nonattainment Area SIP Submissions available at *https://www.epa.gov/sites/default/files/2016-06/documents/20140423guidance_nonattainment_sip.pdf.*

until the 2030 control period or, if earlier, the second control period in which new SCR controls are operated at a unit. The EPA's responses to comments on the backstop daily NO_X emissions rate provisions, including the reasons for these changes, are discussed in the remainder of this section and in section 5 of the *RTC* document.

Comment: Some commenters strongly supported the backstop daily emissions rate provisions, noting their benefit to downwind receptors on potential nonattainment days, their benefit to neighboring communities, and evidence of deterioration in SCR performance in the absence of such provisions. Other commenters stated that the backstop daily emissions rate provisions are unnecessary, either because SCR-equipped EGUs would already be sufficiently incentivized to operate and optimize their controls by the stringency of the state emissions budgets and the resulting allowance prices or because most SCR-equipped EGUs are already required to operate and optimize their SCRs by conditions in their operating permits. Some commenters cited previous EPA analyses showing that it is unusual for SCR-equipped units to turn off their SCRs only on high electricity demand days (HEDD).

Commenters suggested diverse possible changes to the types of EGUs that would be covered by the backstop daily emissions rate provisions. Some commenters stated that the provisions should apply to all EGUs or to all SCR-equipped EGUs, including non-coal-fired units. Other commenters stated that exemptions should be provided for units operating at capacity factors below 10 percent or for emissions during emergencies.

Some commenters stated that implementation of the backstop daily emissions rate provisions would cause unintended and counterproductive consequences. Some of these commenters claimed that by requiring the surrender of extra allowances, the backstop emissions rate provisions would create shortages of allowances for the program overall. Other commenters claimed that the disincentives to operate units subject to the backstop emissions rate provisions would cause load to shift to higher-emitting generators not covered by the trading program (such as sources in states outside the program's geographic region, EGUs smaller than 25 MW, and sources considered demand-side resources, including end-user-sited diesel generator units), potentially resulting in higher overall emissions.

Response: The EPA agrees that backstop daily emissions rate provisions should be implemented and disagrees with comments suggesting that the need for the backstop daily emissions rate provisions is contradicted by previous EPA analyses or is already adequately addressed by other provisions of this rule or other legal requirements. As discussed in sections V.D.1 and VI.B.1.c of this document, the EPA has determined that a control stringency reflecting universal installation and operation of SCR technology at large coal-fired EGUs is appropriate. There are several important differences between this rule and previous actions addressing interstate ozone transport where the Agency did not include such provisions. First, this rule constitutes a full remedy, unlike some prior actions. Second, this rule is the first rule in which the EPA is addressing good neighbor obligations with respect to the more protective 2015 ozone NAAQS. Third, the EPA has examined the most recent data over a broader geographic and temporal footprint specific to the coverage of this rule, and it illustrates a greater degree of SCR performance erosion than in the prior years in which EPA conducted such analysis. Fourth, nonattainment and maintenance for this NAAQS are projected to persist well into the future in EPA's baseline, making enhancements and safeguards such as the backstop daily emissions rate provisions essential for securing elimination of significant contribution in future periods for which fleet configuration is inherently more uncertain.

With respect to claims that inclusion of the backstop daily emissions rate provisions is contradicted by the EPA's earlier analyses concerning SCR operational changes specific to high electricity demand days, the EPA disagrees. Historical data reported to the EPA show that multiple SCR-equipped units across the states covered by this action have chosen not to operate their SCRs, or to operate them at materially less than their full removal capability, for entire ozone seasons. The apparent infrequency of one type of behavior—*i.e.,* instances of units running their controls on most days but turning the controls off specifically on high electricity demand days—does not contradict the evidence concerning another type of behavior—*i.e.,* non-operation or suboptimal operation of controls for entire ozone seasons. The evidence from previous trading programs demonstrates that reliance solely on the incentives created by allowance prices and corresponding static state emissions budgets has been insufficient to cause all SCR-equipped units to operate and optimize their controls for entire ozone seasons.

The EPA acknowledges that some SCR-equipped units are likely already subject to other legal requirements calling for their SCR controls to be operated and optimized such that their seasonal average NO_X emissions rates will generally not exceed 0.08 lb/mmBtu (the level of seasonal SCR performance that the EPA used to derive the equivalent 0.14 lb/mmBtu level of daily SCR performance for the backstop daily NO_X emissions rate). However, commenters do not claim, and the EPA does not believe, that *all* SCR-equipped units are subject to other legal requirements calling for an equivalent degree of SCR operation and optimization. In the context of a multi-state trading program, it is more efficient and equitable, and far more transparent, for the EPA to establish rule provisions uniformly incentivizing all large coal-fired EGUs to install and operate SCR controls than to attempt to establish differentiated requirements for various units according to the EPA's analysis of the effectiveness of their pre-existing permit conditions. Further, to the extent that a given unit's permits already require SCR performance that would meet the backstop emissions rate established in this rule, or to the extent that allowance prices would incentivize the unit to operate the SCR anyway, the EPA expects that the backstop daily emissions rate provisions (as finalized with a 50-ton threshold to address emissions outside an EGU's control before the 3-for-1 surrender ratio applies) will cause no incremental cost for the unit.

The EPA disagrees with the suggested changes to applicability of the backstop emissions rate provisions. With respect to the comments advocating broader coverage, the EPA discusses its reasons for applying the provisions only to coal-fired EGUs in section VI.B.1.c of this document, including the fact that operation of SCR controls is a well-established practice among the best performing coal-fired boilers but not for non-coal-fired units.[334] The comments indicate a preference for a less flexible trading program design than the EPA has found appropriate but do not demonstrate that EPA's decision to allow greater flexibility is either impermissible or unreasonable; our reasoning in this regard is further explained in section VI.B.1.c.i of this

[334] Nationwide and among operating units in 2021, EPA identified the best performing quartile (*i.e.,* lowest ozone season emissions rate) of coal-fired EGU boilers (excluding CFB units). Nearly 100 percent of these units (159 of 160 units) were equipped with SCR controls.

document. With respect to the comments advocating narrower coverage, the commenters have provided no information indicating that the sources for which exemptions are sought could not comply with the provisions, including through the surrender of additional allowances if necessary. The EPA notes that emissions from coal-fired units operating at low capacity factors may be concentrated around days of high electricity demand when incentives to minimize such emissions may be most helpful in mitigating downwind air quality problems. The EPA also notes that to the extent the comments are intended to support exemptions for units without existing SCR controls, the final rule defers application of the backstop emissions rate provisions to such units until the 2030 control period, providing additional flexibility to develop alternatives to the use of such units if the owners choose not to equip them with SCR controls.

Finally, the EPA also disagrees with the comments asserting that the backstop emissions rate provisions would cause unintended and counterproductive consequences. With respect to units already equipped with SCR controls, the EPA expects that by far the most important effect of the provisions will be to incentivize the units to operate and optimize their controls. The EPA sees no basis for speculation that such units would choose to operate in a manner that would result in large amounts of emissions becoming subject to the 3-for-1 allowance surrender ratio or in generation being shifted to sources outside the trading program. The results of the EPA's modeling of benefits and costs of the rule show little leakage of emissions to non-covered sources, and commenters have presented no analysis to the contrary. For instance, as shown in Table 4.6 of the *RIA,* non-covered state ozone season NO_X emissions increased on average by 1 percent over the 2023–2030 time period between the base and final rule scenarios, while covered state emissions fell by 14 percent on average over the same period. With respect to units without existing SCR controls, the EPA expects the backstop emissions rate provisions, when they would take effect for such units, to provide a strong incentive against extensive operation (unless and until such controls are installed), again not resulting in large amounts of emissions becoming subject to the 3-for-1 allowance surrender ratio.

Comment: For units with existing SCR controls, the aspect of the backstop daily emissions rate provisions that received the most attention in comments was how emissions outside the operator's control should be treated. Multiple commenters expressed concern that the backstop daily emissions rate would be exceeded on days when the SCR equipment cannot be operated for all or a portion of the day. The most commonly cited example of a situation where SCR equipment cannot be operated was unit startups, although some commenters also mentioned unit shutdowns, boiler or emissions control malfunctions, and unit maintenance or tests. The commenters expressed the view that emissions that cannot be controlled by SCR equipment should be exempted from the backstop emissions rate provisions and suggested a variety of approaches for implementing an exemption.

Some commenters also stated that the backstop emissions rate provisions would not sufficiently accommodate sustained low-load operation, such as where an SCR-equipped unit operates for extended periods at a load level too low to permit SCR operation so that the unit is ready to ramp up to higher load levels in less time than would be required for a startup. The commenters suggested that implementation of a backstop daily rate would reduce the ability to operate the units in this manner, generally reducing system flexibility. Some noted that the need for flexibility of this nature is increasing because of the rapid growth in intermittent renewable generation.

Additional comments on the backstop daily emissions rate provisions for units with existing SCR controls addressed the level of the daily emissions rate and the implementation timing. With respect to the rate level, various commenters suggested rates from 0.08 to 0.20 lb/mmBtu. With respect to implementation timing, some commenters stated that because immediate compliance was possible, the good neighbor provision required implementation as of the 2023 control period rather than the 2024 control period as proposed. Other commenters expressed the view that units with existing SCR controls should not be required to comply with the backstop emissions rate provisions earlier than units without existing SCR controls. Some owners of SCR-equipped EGUs that exhaust to stacks shared with EGUs without SCR suggested that their particular units with existing SCR controls should not be required to comply with the backstop emissions rate provisions earlier than units without existing SCR controls in order to avoid the cost of upgrading their emissions monitoring equipment.

Response: With respect to the topic of emissions outside an operator's control, as a general matter the EPA agrees that the backstop daily emissions rate provisions are intended to incentivize good SCR operation and that it was not the Agency's intent to apply a higher surrender ratio to emissions that are truly unavoidable, such as emissions occurring before an operator could reasonably initialize SCR operation when a unit is started up. As explained elsewhere in this section, the EPA selected the level of the backstop rate based on analysis of 2021 emissions data showing that for SCR-equipped coal-fired units achieving seasonal average NO_X emissions rates at or below 0.08 lb/mmBtu, more than 99 percent of the units' emissions would fall below a backstop daily emissions rate of 0.14 lb/mmBtu. In response to the comments summarized previously, the EPA has further analyzed 2021 and 2022 emissions data to determine what if any modifications to the proposal might be appropriate to limit the imposition of a 3-to-1 allowance surrender requirement for emissions caused by circumstances outside an operator's control while preserving the intended incentive to operate and optimize SCR controls whenever possible. The analysis showed that for the same set of units achieving seasonal average emissions rates at or below 0.08 lb/mmBtu, the highest total amount of emissions exceeding the backstop daily emissions rate in either the 2021 or 2022 control period for any unit was 48 tons. The Agency views this amount as a reasonable upper bound on the quantity of emissions that might contribute to an exceedance of the backstop emissions rate arising from circumstances outside an operator's control for any coal-fired unit, not just the well-controlled units in the data set analyzed, because the amount generally encompasses all of a unit's emissions occurring in hours when an SCR could not be operated over an ozone season.

Based on this analysis, the backstop daily emissions rate provisions in this final rule exclude the first 50 tons of a unit's emissions in a given control period exceeding the backstop daily emissions rate from incremental allowance surrender requirements. The EPA finds that establishing a threshold of this nature will provide an appropriate maximum exclusion to all coal-fired units for unavoidable emissions caused by circumstances outside the operator's control while maintaining the incentives for less well-controlled units to improve their emissions performance on all days of the ozone season. Well-controlled units will likely have no emissions over the threshold that will be subject to incremental allowance surrender requirements, while for SCR-equipped units not already achieving a seasonal average emissions rates sufficiently low to routinely operate at daily average emissions rates of 0.14 lb/mmBtu or less, the incentive to reduce daily emissions rates will remain in place, because the 50-ton threshold is not expected to encompass all emissions exceeding the backstop daily emissions rate for such units. In contrast to more complicated exceptions suggested by commenters, the 50-ton threshold can be easily integrated into the overall trading program structure with minimal additional recordkeeping and reporting requirements.

With respect to the comments claiming that the inability of some SCR-equipped units to operate their SCR controls at sustained low load levels likewise merits alteration of the backstop daily emissions rate provisions, the EPA disagrees. There is no dispute concerning the technical need for a unit to attain and maintain a certain range of exhaust gas temperatures at the SCR inlet in order to achieve optimal SCR performance and no dispute concerning the general relationship between a unit's load level in a given hour and its ability to attain and maintain that exhaust gas temperature range in that hour. However, the EPA is also aware that at least in some cases, units whose role in the integrated electric system currently calls for them to operate at low load levels for sustained periods (such as overnight) in fact may be able to operate at slightly higher load levels that would accommodate SCR operation during those periods and still meet the needs of the integrated electric system, thereby avoiding operation of the unit for sustained periods with the SCR out of service. Figure B.5 in the EGU NO_X Mitigation Strategies Final Rule TSD illustrates this opportunity using data reported for the 2021 and 2022 ozone seasons by a large SCR-equipped EGU in Pennsylvania. In both ozone seasons, the unit often cycled daily between its maximum load of approximately 900 MW during the daytime and a lower load level overnight, and in both ozone seasons the unit's typical daytime emissions rate was between 0.05 and 0.07 lb/mmBtu. However, while in the 2021 ozone season, the unit cycled down to a load level of approximately 440 MW overnight and did not operate its SCR, in the 2022 ozone season, when allowance prices were considerably higher, the unit cycled down to a load level of approximately 540 MW overnight and did operate its SCR. Despite the higher nighttime generation levels, the result was a decrease of roughly 50 percent in the unit's seasonal average NO_X emissions rate, from approximately 0.14 lb/mmBtu to approximately 0.07 lb/mmBtu, and a comparable reduction in NO_X mass emissions. This unit is not uniquely situated; operating data for several other large SCR-equipped EGUs in Pennsylvania show the same past pattern of cycling down to low load levels at which the SCR controls cannot be operated, and these other units have similar opportunities to cycle down to somewhat higher load levels (necessarily subject to the needs and constraints of the integrated electric system) at which their SCR controls can be operated.[335] No commenter has submitted data to the contrary. Furthermore, this example demonstrates the need for this rule's backstop emissions rate provision, which (had it been in place) would have motivated this facility to operate its SCR overnight during the 2021 ozone season when the prevailing allowance price provided an insufficient incentive to do so.

The EPA disagrees with the comments advocating for a backstop daily emissions rate lower or higher than 0.14 lb/mmBtu. In general, these comments simply represent disagreements with the EPA's conclusions regarding the identification of required emissions reductions under this rule, as reflected in part by the EPA's conclusion that a seasonal average emissions rate of 0.08 lb/mmBtu reasonably reflects the seasonal average emissions rate achievable through optimization of controls by existing SCR-equipped units that are not already achieving a lower seasonal average emissions rate. Comments concerning the selection of the 0.08 lb/mmBtu seasonal average emissions rate are addressed in section V of this document. Commenters did not challenge the EPA's analysis identifying a daily emissions rate of 0.14 lb/mmBtu as comparable in stringency to a seasonal average emissions rate of 0.08 lb/mmBtu (see further discussion elsewhere in this section).

The EPA also disagrees with the comments stating that the backstop daily emissions rate provisions should apply to units with existing SCR controls starting in a control period earlier or later than the 2024 control period. The EPA does not consider implementation of the provisions in the 2023 control period feasible because it is currently unknown whether the necessary updates to the emissions recordkeeping and reporting software for all the affected sources could be completed and tested before July 30, 2023, which is the first quarterly reporting deadline for the 2023 control period. Moreover, as discussed in section VI.B.1.c.i of this document, implementing the requirements starting in 2024 will provide a window for EGUs to improve the consistency of SCR operation or in some cases to optionally install additional emissions monitoring equipment. As for the suggestion that implementation timing of the backstop daily emissions rate provisions for units with existing SCR controls should be synchronized with the later implementation timing for units without existing SCR controls, the EPA is not persuaded that there is any inequity in implementing provisions intended to incentivize operation of SCR controls first at sources that already have such controls and later at sources that do not already have such controls, allowing time for the latter sources to install the controls. In any event, in this instance, where some upwind sources have an immediate and highly cost-effective option for controlling their emissions, the statutory requirement for significant contribution to be eliminated as expeditiously as practicable so as to provide downwind states with the protection intended by the Good Neighbor provision overrides these sources' claim of inequity relative to sources whose emissions control options would take longer and have higher cost. We conclude that the backstop daily emissions rate is an important aspect of the elimination of significant contribution and should be applied at the relevant units. It is only out of recognition of unique circumstances associated with facilitating power-sector transition as identified by commenters, that we defer the application of the rate for the minority of units that have not yet installed SCR controls.

Finally, with respect to the SCR-equipped units that share common stacks with units that do not have SCR, the EPA disagrees that monitoring cost considerations merit a later implementation date for the backstop daily emissions rate provisions. As discussed in section VI.B.10 of this document, five plants with this configuration are covered by the rule (one of which has announced plans to retire in 2023). Under this rule, as proposed, the owner of a plant with this

[335] See the spreadsheet ''Conemaugh and Keystone unit 2021 to 2022 hourly ozone season data'' in the docket.

configuration can choose between either upgrading the plant's monitoring systems so as to obtain unit-specific NO_X emissions rate data for each unit subject to the backstop daily emissions rate or else using the NO_X emissions rate data from the common stack, recognizing that the common stack emissions rate would generally be biased upwards relative to the emissions rate that could be reported for the SCR-equipped unit if that unit's emissions were monitored separately. Commenters have suggested a third option of a temporary exemption from the backstop emissions rate to avoid the cost of upgrading their monitoring systems. With the timing for implementation of the backstop emissions rate provisions for currently uncontrolled units in the proposal, the temporary exemption for the SCR-equipped units would have been in place for three control periods, from 2024 through 2026. With the final rule's deferral of the implementation of the backstop emissions rate provisions for the uncontrolled units for up to three years, the suggested temporary exemption for the SCR-equipped units would be in effect for up to six control periods, from 2024 through 2029. The EPA does not consider it reasonable to allow these SCR-equipped units an exemption from the backstop rate provisions for six years to avoid the cost of upgrading their monitoring systems, particularly given that the additional costs of monitoring at the individual-unit level are already borne by the large majority of other plants and the rule already provides these plants with an alternative to the monitoring system upgrades, if desired, by allowing the plants to use the emissions rate data from the common stack.[336]

Comment: With respect to units without existing SCRs, some commenters viewed the backstop daily emissions rate provisions as likely to make units without SCR altogether unwilling or unable to operate and characterized the provisions as a mandate for such units to install such controls or retire as of the control period when the provisions are implemented. Other commenters acknowledged that the provisions are not actually hard limits but stated that the higher allowance surrender ratio for emissions in excess of the backstop daily rate would nevertheless reduce the ability of such units to operate as needed to back up intermittent renewable generation. Some commenters claimed that inclusion of the backstop daily emissions rate provisions would substantially eliminate the potential benefits of allowance trading, because all units would have to meet the same emissions rate.

Some commenters stated that the proposed application of the daily backstop emissions rate provisions in the 2027 control period in some cases would occur only slightly before the units' otherwise planned retirement dates, and that short-term reliability considerations could create the need to make substantial investments in new controls at the units, which in turn could result in deferral of the units' retirement plans. In the proposal, the EPA requested comment on the possibility of deferring the application of the backstop emissions rate provisions to units without existing SCR controls until the 2029 control period if the owners provided the EPA with information indicating with sufficient certainty that the units would retire by the end of 2028. Commenters in favor of this concept suggested longer deferral periods, ranging from 2029 through 2032, and some also suggested that the EPA should simultaneously enlarge the emissions budgets to provide more allowances for units subject to the deferred requirement. Other commenters opposed any deferral of the applicability of the backstop rate provisions.

Response: The EPA disagrees that implementation of the backstop daily emissions rate provisions for EGUs without existing SCR controls constitutes a mandate for such units to install controls or retire but agrees that, as intended, the provisions would create strong incentives to minimize operation of the units unless and until controls are installed, and further agrees that in some instances retirement and replacement may be a more economically attractive option for the unit's customers and/or owners than installation of new controls. The EPA's rationale for determining at Step 3 that the control stringency required to address states' good neighbor obligations includes achievement of emissions rates consistent with good SCR performance at all large coal-fired EGUs (other than circulating fluidized bed boilers) is discussed in section V.D.1 of this document, and the EPA's rationale for determining at Step 4 that the trading program should include strong unit-level incentives to implement these controls is discussed in section VI.B.1.c. of this document. As noted in section VI.B.1.c of this document, the backstop daily emissions rate provisions are structured as incremental allowance surrender requirements rather than as directly enforceable emissions limits to incentivize improved emissions performance at the individual unit level while continuing to preserve, to the extent possible, the advantages that the flexibility of a trading program brings to the electric power sector. The EPA appreciates that, in comparison to previous transport rules using a trading program mechanism for the power sector, the degree of flexibility available under this rule is reduced both by the greater stringency of the overall emissions reduction requirements, which leave less room to accommodate emissions from high-emitting units such as uncontrolled coal-fired units, and by the backstop daily emissions rate provisions. However, the EPA maintains that the trading program structure still is significantly more flexible than an array of directly enforceable emissions limits imposed on all EGUs or even on all coal-fired EGUs, and the comments do not show otherwise.

With respect to the comments concerning the timing for application of the backstop daily emissions rate provisions to EGUs without existing SCR controls, in the final rule the provisions will apply to these units starting with the second control period in which newly installed SCR controls are operational at the unit, but not later than the 2030 control period. As discussed in section VI.B.1.d of this document, the purpose of this change from the proposal is to address concerns expressed by RTOs and other commenters that application of the backstop daily NO_X emissions rate to EGUs without existing SCR controls starting in the 2027 control period would provide insufficient time for planning and investments needed to facilitate the unit retirements they viewed as likely to be a preferred compliance pathway for some owners. The EPA recognizes that retrofitting new emissions controls on aging coal-fired EGUs may be less environmentally efficient than the alternative of retirement and replacement, which could yield lower cumulative emissions of NO_X and multiple other pollutants over time. The EPA also recognizes that several coal-fired EGUs have already been considering retirement in 2028 (or earlier) under compliance pathways available under the Clean Water Act effluent guidelines[337] and the coal combustion residuals rule under the

[336] The owner of one of the five plants with common stacks submitted comments stating that no location in the plant's ductwork could meet the criteria for a unit-specific monitoring location. As discussed in section VI.B.10 of this document, EPA staff have reviewed the comment and do not believe the commenter has provided sufficient information to reach such a conclusion.

[337] See 40 CFR 423.11(w).

Resource Conservation and Recovery Act.[338] The year 2028 also represents the end of the second planning period under the Regional Haze program, and thus is a significant year in states' planning of strategies to make reasonable progress towards natural visibility at Class I areas.[339] In addition, other regulatory actions at the state or Federal level are being or recently have been proposed. This includes among other things a proposed revision to the PM NAAQS for which transport SIPs would be due later in the 2020s. We understand that EGUs may wish to take the entire regulatory and market landscape into account when deciding whether to invest in SCR or pursue other NO_X reduction strategies. To facilitate a unit-level compliance alternative under this rule that maintains the NO_X reductions corresponding to SCR-level emissions control performance required by the state budgets from 2026 forward and that is potentially superior both economically and environmentally across multiple regulatory programs than installation of new, capital-intensive, post-combustion controls, the EPA is providing the fleet more flexibility in how to achieve those emissions reductions in the years through 2029. Relatedly, the deferral of the application of the backstop emissions rate provisions to uncontrolled units also addresses commenters' concerns that the provisions otherwise would reduce the ability of uncontrolled units to operate as needed to back up intermittent renewable generation (subject of course to the allowance-holding requirements to cover emissions). The deferral addresses this concern directly for the period through 2029, by eliminating application of the backstop provisions to uncontrolled EGUs through this period, and also indirectly after 2029, by ensuring the availability of sufficient time for owners and operators to complete other investments that may be needed to back up renewable generation after that point.

The EPA disagrees with the comments stating that application of the backstop daily emissions rate provisions to uncontrolled units should not be deferred and also disagrees with the comments stating that deferral should be accompanied by increases in the state emissions budgets reflecting higher assumed emissions rates for these units. The responses to these two comments are related. This rule complies with the mandate for the EPA to address good neighbor obligations as expeditiously as practicable and is based on a demonstration that emissions reductions commensurate with the overall emissions control strategy at Step 3 can be achieved beginning in the 2027 ozone season (following a two-year phase in of emissions reductions associated with installation of SCR retrofits). In the *RIA,* we demonstrate that EGUs will have multiple pathways to meeting the state budgets even if they choose not to install the SCR controls—thus no relaxation in the stringency of these budgets has been demonstrated to be warranted based on feasibility, necessity, or impossibility. The EGU economic modeling discussed in the *RIA* illustrates that many sources identified as currently having SCR retrofit potential elect not to install a SCR, and those that do retrofit SCR make no such installation until 2030. Yet, the fleet is able to comply with 2026 state emissions budgets (whose emissions reductions are premised in large part on assumed SCR retrofits) through reduced utilization (many of these units are projected to retire, and thus reduce emissions). While these changes in coal fleet utilization are not required or imposed through the EPA's state emissions budgets, they are projected to be an economic preference for a substantial portion of the unretrofitted fleet owing to future market and policy conditions. If sources do ultimately elect this pathway, then compliance will occur with significantly less demand on SCR retrofit labor and material markets than assumed at Step 3. The daily emissions rates are a backstop to the broader emissions reduction requirements, which we view as an important and necessary component to the elimination of significant contribution. But we also recognize that the objectives to be accomplished by the backstop must be balanced with larger economic and environmental conditions facing EGUs for which a deferral of the backstop rate ultimately is the most reasonable approach given these competing concerns. *See Wisconsin,* 938 F.3d at 320 (''EPA, though, possesses a measure of latitude in defining which upwind contribution 'amounts' count as 'significant[ ]' and thus must be abated.''). As noted in section VI.B.1.d of this document, the EPA finds that as long as state emissions budgets continue to reflect the required degree of emissions reductions at least for an interim period until the backstop rate would apply more uniformly, deferral of the backstop rate requirement for uncontrolled units in recognition of the transition period identified by commenters can be justified on the basis of the greater long-term environmental benefits obtained through greater compliance flexibility.

8. Unit-Specific Emissions Limitations Contingent on Assurance Level Exceedances

As emphasized by the D.C. Circuit in its decision invalidating CAIR, under the CAA's good neighbor provision, emissions ''within the State'' that contribute significantly to nonattainment or interfere with maintenance of a NAAQS in another state must be prohibited. *North Carolina* v. *EPA,* 531 F.3d 896, 906–08 (D.C. Cir. 2008). The CAIR trading programs contained no provisions limiting the degree to which a state could rely on net purchased allowances as a substitute for making in-state emissions reductions, an omission which the court found was inconsistent with the requirements of the good neighbor provision. *Id.* In response to that holding, the EPA established the CSAPR trading programs' assurance provisions to ensure that, in the context of a flexible trading program, the emissions reductions required under the good neighbor provision in fact will take place within the state. The EPA believes the assurance provisions have generally been successful in achieving that objective, as evidenced by the fact that since the assurance provisions took effect in 2017, out of the nearly 300 instances where a given state's compliance with the assurance provisions of a given CSAPR trading program for a given control period has been assessed, a state's collective emissions have exceeded the applicable assurance level only four times.

Unfortunately, the EPA also recognizes that the assurance provisions' very good historical compliance record is not good enough. The four past exceedances all occurred under the Group 2 trading program: sources in Mississippi collectively exceeded their applicable assurance levels in the 2019 and 2020 control periods, and sources in Missouri collectively exceeded their applicable assurance levels in the 2020 and 2021 control periods.[340] Both of the exceedances by Missouri sources could easily have been avoided if the owner and operator of several SCR-equipped,

[338] See 40 CFR 257.103(b).

[339] See 40 CFR 51.308(f).

[340] Information on the assurance level exceedances in the 2019, 2020, and 2021 control periods is available in the final notices concerning EPA's administration of the assurance provisions for those control periods. 85 FR 53364 (August 28, 2020); 86 FR 52674 (September 22, 2021); 87 FR 57695 (September 21, 2022).

coal-fired steam units had not chosen to idle the units' controls and rely instead on net out-of-state purchased allowances. The exceedances were large, and ample quantities of allowances to cover the resulting 3-for-1 allowance surrender requirements were purchased in advance, suggesting that the assurance level exceedances may have been anticipated as a possibility. In the case of the Mississippi exceedances, the exceedances were smaller, operational variability (manifesting as increased heat input) appears to have been a material contributing factor, and the EPA has not concluded that the owners and operators anticipated the exceedances. However, an additional contributing factor was the fact that several large, gas-fired steam units without SCR controls emitted NO_X at average rates much higher than the average emissions rates the same units had achieved in previous control periods. In short, while the Missouri exceedances appear far more significant, the EPA's analysis indicates that all four past exceedances could have been avoided if the units most responsible had achieved emissions rates more comparable to the same units' previous performance. In the EPA's view, the operation of the Missouri units in particular—although not prohibited by the current regulatory requirements—cannot be reconciled with the statutory requirements of the good neighbor provision. The fact that such operation is not prohibited by the current regulations therefore indicates a deficiency in the current regulatory requirements.

To correct the deficiency in the regulatory requirements, the EPA in this rulemaking is revising the Group 3 trading program regulations to establish an additional emissions limitation to more effectively deter avoidable assurance level exceedances starting with the 2024 control period. Because the pollutant involved is ozone season NO_X and the particular sources for which deterrence is most needed are located in states that are transitioning from the Group 2 trading program to the Group 3 trading program, the EPA is promulgating the strengthening provisions as revisions to the Group 3 trading program regulations rather than the Group 2 trading program regulations.[341]

The two historical emissions-related compliance requirements in the Group 3 trading program regulations are both structured in the form of requirements to hold allowances. The first requirement applies at the source level: specifically, at the compliance deadline after each control period, the owners and operators of each source covered by the program must surrender a quantity of allowances that is determined based on the emissions from the units at the source during the control period. The second requirement applies at the designated representative level (which typically is the owner or operator level): if the state's sources collectively emit in excess of the state's assurance level, the owners and operators of each set of sources determined to have contributed to the exceedance must surrender an additional quantity of allowances. As long as a source's owners and operators comply with these two allowance surrender requirements (and meet certain other requirements not related to the amounts of the sources' emissions), they are in compliance with the program.

In light of the operation of the Missouri sources, the EPA is doubtful that strengthening the assurance provisions by increasing allowance surrender requirements at the unit, source, or designated representative level would create a sufficient deterrent. Accordingly, the EPA is instead adding a new, unit-level emissions limitation structured as a prohibition to emit NO_X in excess of a defined amount. A violation of the prohibition will not trigger additional allowance surrender requirements beyond the surrender requirements that would otherwise apply, but will trigger the possible application of the CAA's enforcement authorities. The new emissions limitation will be in addition to, not in lieu of, the other requirements of the Group 3 trading program. This point is being made explicit by relabeling the source-level allowance holding requirement, currently called the ''emissions limitation,'' as the ''primary emissions limitation'' and labeling the new unit-level requirement as the ''secondary emissions limitation.'' (The regulations label the designated representative-level requirement as ''compliance with the . . . assurance provisions.'')

Because the purpose of the new unit-level secondary emissions limitation is to deter conduct causing exceedances of a state's assurance level, the EPA is conditioning applicability of the new limitation on (1) the occurrence of an exceedance of the state's assurance level for the control period, and (2) the apportionment of at least some of the responsibility for the assurance level exceedance to the set of units represented by the unit's designated representative. Apportionment of responsibility for the assurance level exceedance will be carried out according to the existing assurance provision procedures and will therefore depend on the designated representative's shares of both the state's total emissions for the control period and the state's assurance level for the control period. To ensure that the secondary emissions limitation is focused on units where the need for improved incentives is greatest, and also to ensure that the limitation will not apply to units used only to meet peak electricity demand, the limitation applies only to units that are equipped with post-combustion controls (*i.e.,* SCR or SNCR) and that operated for at least ten percent of the hours in the control period in question and in at least one previous control period.

For units to which a secondary emissions limitation applies in a given control period based on the conditions just summarized, the limitation is defined by a formula in the regulations. The formula is generally designed to compute the potential amount the unit would have emitted during the control period, given its actual heat input during the control period, if the unit had achieved an average emissions rate equal to the unit's lowest average emissions rate in a previous control period plus a margin of 25 percent. To ensure that the data used to establish the unit's lowest previous average emissions rate are representative and of high quality, only past control periods where the unit participated in a CSAPR trading program for ozone season NO_X and operated in at least ten percent of the hours in the control period are considered. Further, to avoid causing units that achieve emissions rates lower than 0.08 lb/mmBtu from becoming subject to more stringent secondary emissions limitations in subsequent control periods, the secondary emissions limitation formula uses a

[341] The EPA believes that the occurrence of avoidable assurance level exceedances under the Group 2 trading program, combined with the express statutory directive that good neighbor obligations must be addressed ''within the state,'' and through ''prohibition,'' would also provide a sufficient legal basis for the Agency to promulgate the same revisions to the assurance provisions for all the other CSAPR trading programs. The EPA is not doing so at this time because the Agency has seen no reason to expect exceedances of the assurance levels under any of the other CSAPR trading programs by any of the states that will remain subject to the respective trading programs after this rulemaking, except possibly by Missouri under the CSAPR NO_X Annual Trading Program. The EPA expects that reductions in Missouri's seasonal NO_X emissions sufficient to comply with the proposed provisions of the revised Group 3 trading program, including the secondary emissions limitations, would also prevent exceedances of Missouri's currently applicable assurance level for annual NO_X emissions.

floor emissions rate of 0.10 lb/mmBtu (which is 0.08 lb/mmBtu plus the formula's 25 percent margin). In addition to making sure that performance better than 0.08 lb/mmBtu is not disincentivized, the inclusion of the floor emissions rate also ensures that no unit achieving an average emissions rate of 0.10 lb/mmBtu or less in a given control period will exceed a secondary emissions limitation in that control period. Finally, the formula includes a 50-ton threshold, which will avert violations for small performance deviations at large EGUs and also ensure that no unit emitting less than 50 tons in a given control period will exceed a secondary emissions limitation in that control period.

In summary, a secondary emissions limitation is applicable to a unit for a given control period only if the state's assurance level is exceeded, responsibility for the exceedance is apportioned at least in part to the set of units represented by the unit's designated representative, the unit is equipped with post-combustion controls, and the unit operated for at least ten percent of the hours in the control period. Where a secondary emissions limitation applies to a unit for a given control period, the amount of the limitation is computed as the sum of 50 tons plus the product of (1) the unit's heat input for the control period times (2) a NO_X emissions rate of 0.10 lb/mmBtu or, if higher, 125 percent times the lowest seasonal average NO_X emissions rate achieved by the unit in a previous control period when the unit participated in a CSAPR trading program for ozone season NO_X emissions and operated in at least ten percent of the hours in the control period.[342]

Table VI.B.8–1 shows the secondary emissions limitations that the formula would have produced and which units would have exceeded those limitations if the limitations and formula had been in effect for the Group 2 trading program in 2020 and 2021 when assurance level exceedances occurred in Missouri. Following consideration of comments, the EPA believes that in each case the formula functions in a reasonable manner, and the Missouri units identified as exceeding their respective secondary emissions limitations are sources for which an enforcement deterrent under CAA sections 113 and 304 would have been appropriate to compel better control of NO_X emissions. Table VI.B.8–1 does not show any units that would have been identified as subject to secondary emissions limitations in the case of the 2019 and 2020 assurance level exceedances in Mississippi because no units in the state meeting all conditions for applicability—including the requirement to be equipped with post-combustion controls—exceeded their respective limitations.

TABLE VI.B.8–1—ILLUSTRATIVE RESULTS OF APPLYING SECONDARY EMISSIONS LIMITATION IN PREVIOUS INSTANCES OF ASSURANCE LEVEL EXCEEDANCES

Owner/operator	Unit	125% of Lowest previously achieved NO_X emissions rate (lb/mmBtu)	Actual NO_X emissions rate (lb/mmBtu)	Secondary emissions limitation (tons)	Actual NO_X emissions (tons)	Exceedance (tons)
Missouri—2020						
Assoc. Elec. Coop	New Madrid 1	0.135	0.670	961	4,524	3,563
Assoc. Elec. Coop	New Madrid 2	0.131	0.497	866	3,108	2,242
Assoc. Elec. Coop	Thomas Hill 1	0.123	0.526	374	1,384	1,010
Assoc. Elec. Coop	Thomas Hill 2	0.122	0.537	548	2,187	1,639
Assoc. Elec. Coop	Thomas Hill 3	0.104	0.195	780	1,374	594
Missouri—2021						
Assoc. Elec. Coop	New Madrid 1	0.135	0.652	353	1,466	1,113
Assoc. Elec. Coop	New Madrid 2	0.131	0.611	1,054	4,700	3,646
Assoc. Elec. Coop	Thomas Hill 1	0.123	0.146	421	440	19
Assoc. Elec. Coop	Thomas Hill 2	0.122	0.400	600	1,801	1,201

For further illustrations of the application of the secondary emissions limitation formula to other units in the states to be subject to the expanded Group 3 trading program in the control periods from 2016 through 2021, see the spreadsheet ''Illustrative Calculations Using Proposed Secondary Emissions Limitation Formula,'' available in the docket. The EPA notes that, with the exception of the units listed in Table VI.B.8–1, no unit shown in the spreadsheet as having emissions exceeding the illustrative secondary emissions limitation calculated for the unit would have violated the prohibition because no violation would occur in the absence of an exceedance of the assurance level and apportionment of responsibility for a share of the exceedance to the unit under the assurance provisions.

The secondary emissions limitation provisions are being finalized as proposed except for the addition of the condition that a unit to which the provisions apply must be equipped with post-combustion controls. The EPA's responses to comments concerning the secondary emissions limitation provisions, including the comments giving rise to the change just mentioned, are in the remainder of this section and section 5 of the *RTC* document.

Comment: Some commenters stated that the secondary emissions limitation is not necessary, or would be a disproportionate remedy, because experience shows that exceedances of the assurance level have been rare, and where exceedances of a state's assurance level have occurred, the 3-for-1 surrender ratio under the existing regulations has applied, providing a sufficient remedy.

Response: The EPA disagrees with these comments. The purpose of the assurance provisions in the CSAPR trading programs is to ensure that the emissions reductions required to address a state's obligations under the Good Neighbor Provision occur ''within the state'' as mandated by the CAA. See *North Carolina* v. *EPA,* 531 F.3d 896, 906–08 (D.C. Cir. 2008). Prior to this action, the sole consequence for an exceedance of a state's assurance level

[342] For the actual regulatory language, see 40 CFR 97.1025(c) as added by this rule.

has been a requirement to surrender two additional allowances for each ton of the exceedance. The repeated, large, foreseeable, and easily avoidable exceedances of Missouri's assurance level under the Group 2 trading program in 2020 and 2021 have made clear that a remedy based solely on additional allowance surrenders is insufficient to address this statutory requirement and that a materially stronger deterrent is needed.

Comment: Some commenters stated that the secondary emissions limitation could apply to exceedances caused by factors outside the control of the EGU operator, going beyond the EPA's intent of deterring exceedances that are foreseeable and avoidable. For example, commenters pointed out that some units that typically combust gas may sometimes be ordered to combust oil at times when supplies of gas are constrained and expressed concern that the resulting higher NO_X emissions could cause a unit to exceed its secondary emissions limitation. Another commenter stated that it is not uncommon for units' seasonal average NO_X emissions rate to vary by more than 25 percent across control periods.

Response: The EPA agrees that the secondary emissions limitation is intended to apply to units in a position to avert an exceedance of a state's assurance level. The contention that year-to-year variability of 25 percent in units' seasonal average emissions rates is common is not in itself a persuasive reason to omit the secondary emissions limitation from the final rule, because the mere existence of such variability says nothing about whether the operators of those units could reduce that variability through their operational decisions, and the commenter provided no data regarding the extent to which the historical variability was avoidable. However, the EPA agrees that a secondary emissions limitation should be designed to avoid application to a unit whose increase in emissions rate was caused by mandated combustion of a higher-NO_X fuel than the unit's normal fuel. Moreover, based on the analysis of the secondary emissions limitation formula prepared for the proposal, the EPA has reviewed the applicability of the limitation more generally and has determined that it should apply only to units with post-combustion controls, which are the units with the greatest ability to manage their emissions rates through their operating behavior. This modification will avoid application of a secondary emissions limitation in situations where a unit's increase in seasonal average NO_X emissions rate relative to past control periods is caused by factors in that control period beyond the operator's control, such as being mandated by a regulator to combust a higher proportion of oil or operating for a higher proportion of hours at load levels where the unit has a higher NO_X emissions rate for reasons other than non-operation of emissions controls.

Comment: Some commenters asserted that because it is not known if a state's assurance level has been exceeded until after the end of the control period, EGU operators would be unable to know whether the secondary emissions limitation would apply to them during the control period. Some of these commenters suggested that where a unit has been found to have contributed to an assurance level exceedance, the EPA should apply a secondary emissions limitation to the unit not in that control period but instead in the following control period.

Commenters suggested that uncertainty about whether a unit would be subject to a secondary emissions limitation could have a variety of undesirable consequences. For example, they asserted that some EGUs could become unwilling to operate when needed for reliability because they would be concerned that merely operating more than in previous control periods could cause a unit to exceed its limitation. One commenter asserted that the uncertainty would make it difficult for an owner of multiple EGUs to use allowances allocated to one EGU to meet another EGU's surrender requirements, possibly leading to operating restrictions on multiple EGUs.

Response: The EPA disagrees with these comments. While an operator cannot be certain that the secondary emissions limitation *will* apply to a particular EGU until after the end of a control period, the operator can be certain that the limitation *will not* apply to a particular EGU simply by ensuring that the unit's seasonal average NO_X emissions rate does not exceed the higher of 0.10 lb/mmBtu or 125 percent of the unit's lowest seasonal average NO_X emissions rate in a previous control period under a CSAPR trading program (excluding control periods where the unit operated for less than 10 percent of the hours). Because any operator of a unit with post-combustion controls can readily avoid being subject to the limitation, there is no need for application of the limitation to be deferred to the following control period. Deferral of the limitation's application would also have the effect of excusing a unit's first contribution to an assurance level exceedance, which the EPA views as inappropriate when that exceedance could have been avoided.

The asserted possible consequences of uncertainty about whether the limitation would apply rest on mischaracterizations of the provision. The formula for the limitation reflects the unit's actual heat input for the control period, so there is no penalty for increased operation as long as the unit's seasonal NO_X average emissions rate stays below the level just referenced. Finally, nothing about the secondary emissions limitation disincentivizes an EGU fleet owner from transferring allocated allowances among the fleet's EGUs, because apportionment of responsibility for an assurance level exceedance—one of the conditions for application of the secondary emissions limitation—is determined at the level of the group of units represented by a common designated representative (typically the set of all units operated by a particular owner) rather than the individual unit.

Comment: Some commenters stated that the EPA should revise the secondary emissions limitation formula so that where a limitation applies to a unit, the unit's previous NO_X emissions rate used in the formula would not be subject to any floor. These commenters also recommended that if the secondary emissions limitation provisions are not finalized, the EPA instead should raise the allowance surrender ratio applied to exceedances of the assurance level in this final rule.

Response: The EPA disagrees with the suggestion to remove the emissions rate floor from the secondary emissions limitation formula, which would have the effect of making the limitation more stringent for any unit that has achieved a seasonal average NO_X emissions rate lower than 0.08 lb/mmBtu in a past control period. As indicated by their label, the secondary emissions limitation provisions play a secondary role in the Group 3 trading program regulations, specifically to provide the strongest possible deterrent against conduct leading to foreseeable and avoidable exceedances of a state's assurance level. The distinguishing feature of the secondary emissions limitation provisions is therefore the remedy for an exceedance, which is potential application of the CAA's enforcement authorities. The trading program's primary role of achieving required emissions reductions in a more flexible and cost-effective manner than command-and-control regulation is played by the primary emissions limitation provisions, which are structured as allowance surrender requirements. Within this overall trading program structure, the EPA considers it sufficient for the operation of units at emissions rates lower than 0.08 lb/mmBtu to be incentivized through the allowance surrender requirements instead of being mandated through potential application of the CAA's enforcement authorities.

The recommendation to raise the allowance surrender ratio applicable to exceedances of the assurance level if the secondary emissions limitation is not finalized is moot because the secondary emissions limitation is being finalized.

9. Unit-Level Allowance Allocation and Recordation Procedures

In this rule, the EPA is establishing default procedures for allocating CSAPR NO_X Ozone Season Group 3 allowances (''Group 3 allowances'') in amounts equal to each state emissions budget for each control period among the sources in the state for use in complying with the Group 3 trading program. Like the allocation processes established in CSAPR, the CSAPR Update, and the Revised CSAPR Update, the revised allocation process finalized in this rule is designed to provide default allowance allocations to all units that are subject to allowance holding requirements. The EPA's allocations and allocation procedures apply for the 2023 control period [343] and, by default, for subsequent control periods unless and until a state or tribe provides state-determined or tribe-determined allowance allocations under an approved SIP revision or tribal implementation plan.[344]

The default allocation process for the Group 3 trading program as updated in this rule involves three main steps. First, portions of each state emissions budget for each control period are reserved for potential allocation to units that are subject to allowance holding requirements and that might not otherwise receive allowance allocations in the overall allocation process, including both ''existing'' units in any areas of Indian country not subject to a state's CAA implementation planning authority as well as ''new'' units anywhere within a state's borders.[345] Second, in advance of each control period, the unreserved portion of the state budget is allocated among the state's eligible existing units, any portion of the state budget reserved for existing units in Indian country not subject to the state's CAA implementation planning authority is allocated among those units, and the allocations are recorded in the respective sources' compliance accounts. Finally, after the control period but before the compliance deadline by which sources must hold allowances to cover their emissions for the control period, allowances from the portion of the budget reserved for new units are allocated to qualifying units, any remaining reserved allowances not allocated to qualifying units are allocated among the state's existing units, and the allocations are recorded in the respective sources' compliance accounts.

While the overall three-step allocation process summarized in this section was also followed in CSAPR, the CSAPR Update, and the Revised CSAPR Update, in this rule the EPA is making revisions to each step to better address units in Indian country and to better coordinate the unit-level allocation process with the dynamic budget-setting process discussed in section VI.B.4 of this document. The revisions to the three steps are discussed in sections VI.B.9.a, VI.B.9.b, and VI.B.9.c, respectively.

a. Set-Asides of Portions of State Emissions Budgets

The first step of the overall unit-level allocation process for a given control period involves reserving portions of each state's budget for the control period in ''set-asides.'' In this rule, the EPA is making several revisions affecting the establishment of set-asides. The first revision, which is largely unrelated to the other aspects of this rulemaking, will update the regulations for the Group 3 trading program [346] to reflect the D.C. Circuit's holding in *ODEQ* v. *EPA* that the relevant states have initial CAA implementation planning authority in non-reservation areas of Indian country until displaced by a demonstration of tribal jurisdiction over such an area.[347] Consistent with this holding, the EPA is revising language in the Group 3 trading program regulations that prior to this rule, for purposes of allocating allowances from a given state's emissions budget, distinguished between (1) the set of units within the state's borders that are not in Indian country and (2) the set of units within the state's borders that are in Indian country. As revised, the provisions now distinguish between (1) the set of units within the state's borders that are not in Indian country or are in areas of Indian country covered by the state's CAA implementation planning authority and (2) the set of units within the state's borders that are in areas of Indian country not covered by the state's CAA implementation planning authority. The revised language more accurately distinguishes which units are, or are not, covered by a state's CAA implementation planning authority, which is the underlying purpose for which the term ''Indian country'' is currently used in the allowance allocation provisions. The effect of the revision is that any units located in areas of ''Indian country'' as defined in 18 U.S.C. 1151 that are covered by a state's CAA implementation planning authority will be treated for allowance allocation purposes in the same manner as units in areas of the state that are not Indian country, consistent with the *ODEQ* holding.[348]

The remaining revisions, which are interrelated, concern the types of set-asides that in the context of this rule will best accomplish the goal of ensuring the availability of allocations to units that are subject to allowance holding requirements and that would

[343] The rule does not include an option for states to replace the EPA's unit-level allocations for the 2023 control period because the Agency believes a process for obtaining appropriately authorized allowance allocations determined by a state or tribe could not be completed in time for those allocations to be recorded before the end of the 2023 control period.

[344] The options for states to submit SIP revisions that would replace the EPA's default allowance allocations are discussed in sections VI.D.1, VI.D.2, and VI.D.3 of this document. Similarly, for a covered area of Indian country not subject to a state's CAA implementation planning authority, a tribe could elect to work with the EPA under the Tribal Authority Rule to develop a full or partial tribal implementation plan under which the tribe would determine allowance allocations that would replace the EPA's default allocations for subsequent control periods.

[345] Under this rule, the unit-level allocations to ''existing'' units are generally computed in the year before the year of each control period, and the determination of whether to treat a particular unit as existing for purposes of that control period's allocations is made as part of the allocation process, generally based on whether the Agency has the data needed to compute an allocation for the unit as an existing unit. A unit that is subject to allowance holding requirements for a given control period and that did not receive an allocation for that control period as an existing unit is generally eligible to receive an allocation from the portion of the budget reserved for ''new'' units. For further discussion of which units are considered eligible for allocations as existing units or new units in particular control periods, see sections VI.B.9.b and VI.B.9.c.

[346] As discussed in section VI.B.13, the EPA is also making this revision to the regulations for the other CSAPR trading programs in addition to the Group 3 trading program.

[347] For additional discussion of the *ODEQ* v. *EPA* decision and other issues related to the CAA implementation planning authority of states, tribes, and the EPA in various areas of Indian country, *see* section III.C.2.

[348] The EPA notes that the units that will be treated for allocation purposes in the same manner as units not in Indian country will include units in any areas of Indian country subject to a state's CAA implementation planning authority, whether those are non-reservation areas (consistent with *ODEQ*) or reservation areas (such as areas of Indian country within Oklahoma's borders covered by the EPA's October 1, 2020 approval of Oklahoma's request under SAFETEA, as discussed in section III.C.2).

not otherwise receive allowance allocations. One revision to the types of set-asides addresses allocations to existing units in Indian country. The revised geographic scope of the Group 3 trading program under this rule will for the first time include an existing EGU in Indian country not covered by a state's CAA implementation planning authority—the Bonanza coal-fired unit in the Uintah and Ouray Reservation within Utah's borders. To provide an option for Utah (or a similarly situated state in the future) to replace the Agency's default allowance allocations to most existing units with state-determined allocations through a SIP revision while continuing to ensure the availability of a default allocation to the Bonanza unit, which is not subject to the state's jurisdiction or control (or similarly situated units in the future), the EPA is revising the Group 3 trading program regulations to provide for ''Indian country existing unit set-asides.'' Specifically, for each state and for each control period where the set of units within a state's borders eligible to receive allocations as existing units includes one or more units [349] in an area of Indian country not covered by the state's CAA implementation planning authority, the EPA will reserve a portion of the state's emissions budget in an Indian country existing unit set-aside for the unit or units. The amount of each Indian country existing unit set-aside will equal the sum of the default allocations that the units covered by the set-aside would receive if the allocations to all existing units within the state's borders were computed according to EPA's default allocation procedure (which is discussed in section VI.B.9.b of this document). Immediately after determining the amount of a state's emissions budget for a control period (and after reserving a portion for potential allocation to new units, as discussed later in this section), the EPA will first determine the default allocations for all existing units within the state's borders, then allocate the appropriate quantity of allowances to the Indian country existing unit set-aside, then allocate the allowances from the set-aside to the covered units in Indian country, and finally record the allocations in the sources' compliance accounts at the same time as the allocations to other sources not in Indian country. The existence of the Indian country existing unit set-aside thus will have no substantive effect unless and until the relevant state chooses to replace the EPA's default allowance allocations through a SIP revision, in which case the state would have the ability to establish state-determined allocations for the units subject to the state's CAA implementation planning authority while the EPA would continue to administer the Indian country existing unit set-aside for the units in Indian country not covered by the state's CAA implementation planning authority.[350] The EPA believes the establishment of Indian country existing unit set-asides accomplishes the objective of allowing states to control allowance allocations to units covered by their CAA implementation planning authority while ensuring that the allocations to units in Indian country not covered by such authority remain under Federal authority (unless replaced by a tribal implementation plan).

The remaining revisions to the types of set-asides address the set-asides used to ensure availability of allowance allocations to *new* units in light of the division of the budget for *existing* units into a reserved portion for existing units in Indian country and an unreserved portion for other existing units. Under the Group 3 trading program regulations as in effect before this rule, allowances for new units have been provided from separate new unit set-asides and Indian country new unit set-asides. Under this rule, the EPA is combining these two types of set-asides starting with the 2023 control period by eliminating the Indian country new unit set-asides and expanding eligibility for allocations from the new unit set-asides to include units anywhere within the relevant states' borders. However, as with the Indian country new unit set-asides under the current regulations, the EPA will continue to administer the new unit set-asides in the event a state chooses to replace the EPA's default allocations to existing units with state-determined allocations, thereby ensuring the availability of allocations to any new units not covered by a state's CAA implementation planning authority.

The reason for the revisions to the new unit set-asides and Indian country new unit set-asides is to avoid unnecessary and potentially inequitable changes to the degree to which individual existing units contribute to, or benefit from, the new unit set-asides. The allowances used to establish these set-asides are reserved from each state emissions budget before determination of the allocations from the unreserved portion of the budget to existing units, so that certain existing units—generally those receiving the largest allocations—contribute to creation of the set-asides through roughly proportional reductions in their allocations. Later, if any allowances in a set-aside are not allocated to qualifying new units, the remaining allowances are reallocated to the existing units in proportion to their initial allocations from the unreserved portion of the budget, so that certain existing units—again, generally those receiving the largest allocations—benefit from the reallocations in rough proportion to their previous contributions.[351] The EPA believes maintaining this symmetry, where the same existing units—whether in Indian country or not—both contribute to and potentially benefit from the set-asides, is a reasonable policy objective, and doing so requires that the EPA continue to administer the new unit set-asides in the event a state chooses to replace the EPA's default allocations to existing units with state-determined allocations, because otherwise the EPA would be unable to maintain Federal implementation authority and ensure that the units in Indian country would receive an appropriate share of any reallocated allowances.[352] The principal difference between the new unit set-asides and the Indian country new unit set-asides under the regulations in effect before this rule was that, if a state chose to replace the EPA's default allocations with state-determined allocations, the state would take over administration of the new unit set-aside, but not any Indian country new unit set-aside.

[349] In coordination with the dynamic budgeting process discussed in section VI.B.4, each unit included in the unit inventory used to determine a state's dynamic emissions budget for a given control period in 2026 or a later year will be considered an ''existing'' unit for that control period for purposes of the determination of unit-level allowance allocations. In other words, there will no longer be a single fixed date that divides ''existing'' from ''new'' units.

[350] As noted in section VI.D, a tribe could elect to work with EPA under the Tribal Authority Rule to develop a full or partial tribal implementation plan under which the tribe would determine allowance allocations for units in the relevant area of Indian country that would replace EPA's default allocations for subsequent control periods.

[351] Under the regulations in effect before this final rule, allowances from an Indian country new unit set-aside that are not allocated to qualifying new units in Indian country are first transferred to the state's new unit set-aside, and if the allowances are not allocated to qualifying new units elsewhere within the state's borders, the allowances are then reallocated to the state's existing units.

[352] If units in Indian country were unable to share in the benefits of reallocation of allowances from the new unit set-asides, it would be possible to achieve a different form of symmetry by simultaneously exempting the units in Indian country from the obligation to share in the contribution of allowances to the new unit set-asides. However, some stakeholders might view this alternative as potentially inequitable because existing units in Indian country would then make no contributions toward the new unit set-aside while other existing units would still be required to do so.

Under the revised regulations finalized in this rule, states will not be able to take over administration of the new unit set-asides in this situation. Therefore, there is no longer any reason to establish separate Indian country new unit set-asides in order to preserve Federal (and potentially tribal) authority to implement the rule in areas of Indian country subject to tribal jurisdiction.

With respect to the total amounts of allowances that will be set aside for potential allocation to new units from the emissions budgets for each state, for the control periods in 2023 through 2025 (but not for subsequent control periods, as discussed later in this section), the EPA is establishing total set-aside amounts equal to the projected amounts of emissions from any planned units in the state for the control period, plus an additional base 2 percent of the state emissions budget to address any unknown new units, with a minimum total amount of 5 percent. For example, if planned units in a state are projected to emit 4 percent of the state's NO_X ozone season emissions budget, then the new unit set-aside for the state would be set at 6 percent, which is the sum of the 4 percent for planned units plus the base 2 percent for unknown new units. Alternatively, if planned new units are projected to emit only 1 percent of the state's budget, the new unit set-aside would be set at the minimum 5 percent amount. Except for the addition of the 5 percent minimum, which is a change being made in response to comments, the approach to setting the new unit set-aside amounts is generally the same approach previously used to establish the amounts of new unit set-asides in CSAPR, the CSAPR Update, and the Revised CSAPR Update for all the CSAPR trading programs. *See, e.g.,* 76 FR 48292 (August 8, 2011).

As under the Revised CSAPR Update, the EPA is making an exception for New York for the 2023 through 2025 control periods, establishing a total new unit set-aside amount for each control period of 5 percent of the state's emissions budget, with no additional consideration for planned units, because this approach is consistent with New York's preferences as reflected in an approved SIP addressing allowance allocations for the Group 2 trading program.

The final regulations issued under this rule specify the new unit set-aside amounts in terms of the percentages of the state emissions budgets. The amounts are shown in Tables VI.B.9.a–1, VI.B.9.a–2, and VI.B.9.a–3 of this document show the tonnage amounts of the new unit set-asides for the control periods in 2023 through 2025 that are computed by multiplying the new unit set-aside percentages by the preset budgets finalized in this rule for those control periods. The amounts of the 2023 new unit set-asides are illustrative because they do not reflect the impact of transitional adjustments included in the rule that that are likely to affect the 2023 budgets as implemented.[353] The amounts of the 2024 and 2025 new unit set-asides are the actual amounts, because the 2024 and 2025 budgets computed in this rule are the budgets that will be implemented, without any need for transitional adjustments.

TABLE VI.B.9.a–1—ILLUSTRATIVE CSAPR NO_X OZONE SEASON GROUP 3 NEW UNIT SET-ASIDE (NUSA) AMOUNTS FOR THE 2023 CONTROL PERIOD

State	Emissions budgets (tons)	New unit set-aside amount (percent)	New unit set-aside amount (tons)
Alabama	6,379	5	319
Arkansas	8,927	5	446
Illinois	7,474	5	374
Indiana	12,440	5	622
Kentucky	13,601	5	680
Louisiana	9,363	5	468
Maryland	1,206	5	60
Michigan	10,727	5	536
Minnesota	5,504	5	275
Mississippi	6,210	5	311
Missouri	12,598	5	630
Nevada	2,368	9	213
New Jersey	773	5	39
New York	3,912	5	196
Ohio	9,110	6	547
Oklahoma	10,271	5	514
Pennsylvania	8,138	5	407
Texas	40,134	5	2,007
Utah	15,755	5	788
Virginia	3,143	5	157
West Virginia	13,791	5	690
Wisconsin	6,295	5	315

[353] As discussed in section VI.B.12, the EPA expects that this final rule will become effective after May 1, 2023, causing the emissions budgets for the 2023 control period to be adjusted under the rule's transitional provisions so as to ensure that the new budgets will apply only after the rule's effective date. The actual new unit set-asides for the 2023 control period will be computed using the adjusted budgets, but the 2023 budget amounts shown in Table VI.B.9.a–1 do not reflect these adjustments.

TABLE VI.B.9.a–2—CSAPR NO_X OZONE SEASON GROUP 3 NEW UNIT SET-ASIDE (NUSA) AMOUNTS FOR THE 2024 CONTROL PERIOD

State	Emissions budgets (tons)	New unit set-aside amount (percent)	New unit set-aside amount (tons)
Alabama	6,489	5	324
Arkansas	8,927	5	446
Illinois	7,325	5	366
Indiana	11,413	5	571
Kentucky	12,999	5	650
Louisiana	9,363	5	468
Maryland	1,206	5	60
Michigan	10,275	5	514
Minnesota	4,058	5	203
Mississippi	5,058	5	253
Missouri	11,116	5	556
Nevada	2,589	9	233
New Jersey	773	5	39
New York	3,912	5	196
Ohio	7,929	6	476
Oklahoma	9,384	5	469
Pennsylvania	8,138	5	407
Texas	40,134	5	2,007
Utah	15,917	5	796
Virginia	2,756	5	138
West Virginia	11,958	5	598
Wisconsin	6,295	5	315

TABLE VI.B.9.a–3—CSAPR NO_X OZONE SEASON GROUP 3 NEW UNIT SET-ASIDE (NUSA) AMOUNTS FOR THE 2025 CONTROL PERIOD

State	Emissions budgets (tons)	New unit set-aside amount (percent)	New unit set-aside amount (tons)
Alabama	6,489	5	324
Arkansas	8,927	5	446
Illinois	7,325	5	366
Indiana	11,413	5	571
Kentucky	12,472	5	624
Louisiana	9,107	5	455
Maryland	1,206	5	60
Michigan	10,275	5	514
Minnesota	4,058	5	203
Mississippi	5,037	5	252
Missouri	11,116	5	556
Nevada	2,545	9	229
New Jersey	773	5	39
New York	3,912	5	196
Ohio	7,929	6	476
Oklahoma	9,376	5	469
Pennsylvania	8,138	5	407
Texas	38,542	5	1,927
Utah	15,917	5	796
Virginia	2,756	5	138
West Virginia	11,958	5	598
Wisconsin	5,988	5	299

For control periods in 2026 and later years, the EPA will allocate a total of 5 percent of each state emissions budget to a new unit set-aside, with no additional amount for planned new units. The amounts of the set-asides for each state and control period will be computed when the emissions budgets for the control period are established, by May 1 of the year before the year of the control period. The procedure for determining the amounts of the set-asides based on the amounts of the state emissions budgets is being codified in the Group 3 trading program regulations and will reflect the same percentage of the emissions budget for all states.

The purpose of the change to the procedure for establishing the amounts of the set-asides is to coordinate with the dynamic budget-setting process that may be used to determine budgets beginning with the 2026 control period. As discussed in section VI.B.4 of this document, under the dynamic budget-setting process, each state's budget for each control period will be computed using fleet composition information and the total ozone season heat input reported by all affected units in the state for the most recent control periods before the budget-setting computations. (For example, 2026 emissions budgets would be based on 2022–2024 state-level heat input data.) Moreover, as discussed in section VI.B.9.b of this document, the set of units eligible to receive allocations as ''existing'' units in a given control period will generally be the set of units that operated in the control period two years earlier (with the exception of any units whose monitor certification deadlines fell after the start of that earlier control period). Consequently, by the 2025 control period, all or almost all units that commenced commercial operation before issuance of this rule will be considered ''existing'' units for purposes of budget-setting and allocations, and units commencing commercial operation after issuance of this rule generally will be considered ''existing'' units for all but their first two full control periods of operation (and possibly a preceding partial control period). Given that new units will not be relying on the new unit set-asides as a permanent source of allowances, as is the case for ''new'' units under the other CSAPR trading programs, the EPA believes it is unnecessary to establish set-aside percentages for some states that are permanently larger than 5 percent based solely on the fact that projected emissions from planned new units happen to be a somewhat larger proportion of those states' overall budgets at the time of this rule's issuance.

The changes to the structure and amounts of set-asides in this rule largely follow the proposal. The EPA received few comments on these topics. As noted previously, one commenter expressed the view that if the amounts of the new unit set-asides were based on 2 percent of the respective states' budgets, the set-asides would be too small in certain circumstances, and in response the final rule bases the amounts of the set-asides on a floor percentage of 5 percent instead of 2 percent. The remaining commenters expressed a concern that the final rule's provisions regarding set-asides should ensure that any tribal decisions relating to allowance allocations would not be constrained by state decisions. The EPA had this same concern in mind when designing the rule and believes that the final set-aside structure—encompassing Indian country existing unit set-asides as well as EPA-administered new unit set-asides for sources in all areas within each state's borders—fully addresses the concern, is equitable, and preserves Federal and tribal authority under this rule for areas of Indian country subject to tribal jurisdiction. The comments and the EPA's responses are discussed in greater detail in section 1 of the *RTC* document.

b. Allocations to Existing Units, Including Units That Cease Operation

In conjunction with the new and revised state emissions budget-setting methodology for the Group 3 trading program finalized in this rulemaking, the EPA is necessarily establishing a revised procedure for making unit-level allocations of Group 3 allowances to existing units.[354] The procedure that the EPA is employing to compute the unit-level allocations is very similar but not identical to the procedure used to compute unit-level allocations for units subject to the Group 3 trading program in the Revised CSAPR Update. The steps of the procedure for determining allocations from each state emissions budget for each control period are described in detail in the Unit-Level Allowance Allocations Final Rule TSD. The steps are summarized in the following paragraphs, with changes from the procedure followed in the Revised CSAPR Update noted.

In the first step, the EPA identifies the list of units eligible to receive allocations for the control period. The unit inventories used to compute unit-level allocations for the control periods in 2023 through 2025 are the same inventories that have been used to determine the preset emissions budget for these control periods. These inventories have been determined in this rulemaking in essentially the same manner as in the Revised CSAPR Update. The procedures for updating the unit inventories for these control periods are discussed in section VI.B.4 of this document, and the criteria that the EPA has applied to determine whether a unit's scheduled retirement is sufficiently certain to serve as a basis for adjusting emissions budgets and unit-level allocations, are discussed in section V.B of this document and in the Ozone Transport Policy Analysis Final Rule TSD.

The unit inventories used to compute unit-level allocations for control periods in 2026 and later years will be determined in the year before the control period in question based on the latest reported emissions and operational data, which is an extension of the methodology used in the Revised CSAPR Update to reflect more recent data (for example, the unit inventories used to compute 2026 budgets and allocations will reflect reported data up through the 2024 control period). These inventories, which are generally the same as the inventories used to compute dynamic budgets for each control period, include any unit whose monitor certification deadline was no later than the start of the relevant historical control period and that reported emissions data during the relevant historical control period. The EPA notes that basing the list of eligible units on the list of units that reported heat input in the control period two years earlier than the control period for which allocations are being determined represents a revision to the Group 3 trading program regulations as in effect before this rule concerning the treatment of allocations to retired units. Under the prior regulations, units that cease operations for two consecutive control periods would continue to receive allocations as existing units for three additional years (that is, a total of five years) before the allowances they would otherwise have received are reallocated to the new unit set-aside for the state. Under the regulations as revised in this rule, units that cease operation will receive allocations for only two full control periods of non-operation. While the EPA has in prior transport rulemakings noted a qualitative concern that ceasing allowance allocations prematurely could distort the economic incentives of EGUs to continue operating when retirement is more economical, the EPA believes that anticipated market conditions (in particular, the incentives toward power sector transition to cleaner generating sources), particularly in the later 2020s, are such that a continuation of allowance allocations to retiring units likely has no more than a de minimis effect on the consideration of an EGU whether to retire or not.

In the second step of the procedure for determining allocations to existing units, the EPA will compile a database containing for each eligible unit the unit's historical heat input and total NO_X emissions data for the five most recent ozone seasons. For each unit, the EPA will compute an average heat input value based on the three highest non-zero heat input values over the 5-year period, or as the average of all the non-zero values in the period if there are fewer than three non-zero values. For each unit, the EPA will also determine the maximum total NO_X emissions value over the 5-year period. For coal-

[354] The revisions to the procedures for computing unit-level allowance allocations in this rulemaking apply only to the Group 3 trading program. In this rulemaking, the EPA is not reopening the methodology for computing the amounts of allowances allocated to any unit under any other CSAPR trading program.

fired units of 100 MW or larger, the EPA will further determine a ''maximum controlled baseline'' NO_X emissions value, computed as the unit's maximum heat input over the 5-year period times a NO_X emissions rate of 0.08 lb/mmBtu. The maximum controlled baseline will serve as an additional cap on unit-level allocations for all such coal-fired units starting with the control periods in which the assumed use of SCR controls at the units is reflected in the state emissions budgets. Thus, the maximum controlled baseline will apply for purposes of allocations to units with existing SCR controls for all control periods starting with the 2024 control period and for all other coal-fired units of 100 MW or more (except circulating fluidized bed units) starting with the 2027 control period. These procedures are nearly identical to the procedures used in the Revised CSAPR Update, with three exceptions. First, instead of using only the data available at the time of the rulemaking, for each control period the EPA will use data from the most recent five control periods for which data had been reported. (For example, for the 2026 control period, the EPA will use data for the 2020–2024 control periods.) Second, to simplify the data compilation process, the EPA will use only a five-year period for NO_X mass emissions, in contrast to the 8-year period used in the Revised CSAPR Update for NO_X mass emissions. Third, the use of the maximum controlled baseline as an additional cap on emissions is a change adopted in this rule in response to comments received on the proposal. Specifically, commenters observed that if a state's emissions budget is decreased to reflect an assumption that a particular unit in the state is capable of reducing its emissions through the installation of new SCR controls, but the historical emissions cap applied to that unit in the unit-level allocation methodology does not reflect use of the new controls, then the allocation methodology could have the effect of reducing unit-level allocations to the other units in the state whose historical emissions already reflect use of existing controls rather than the unit assumed to install new controls. The EPA agrees with the comment and in this rule has added the maximum controlled baseline provision to the allocation methodology to mitigate the potential effect identified by the commenters.

In the third step of the procedure for determining allocations to existing units in each state, the EPA will allocate the available allowances for that state among the state's eligible units in proportion to the share each unit's average heat input value represents of the total of the average heat input values for all the state's eligible units, but not more than the unit's maximum total NO_X value or, if applicable, the unit's maximum controlled baseline. If the allocations to one or more units are curtailed because of the units' applicable caps, the EPA will iterate the calculation procedure as needed to allocate the remaining allowances, excluding from each successive iteration any units whose allocations have already reached their caps. (If all units in a state reach their caps, any remaining allowances are allocated in proportion to the units' average heat input values, notwithstanding the caps.) This calculation procedure is identical to the calculation procedure used in the Revised CSAPR Update (as well as the CSAPR Update and CSAPR), but using caps that reflect both the units' maximum historical NO_X values and also, where applicable, the maximum controlled baseline values.

Illustrative unit-level allocations for the 2023 control period and final unit-level allocations for the 2024 and 2025 control periods are being determined in this rulemaking based on the emissions budgets for those control periods also determined in the rulemaking and are included in the docket. The 2023 allocations are only illustrative because, as discussed in section VI.B.12.a, the EPA expects the effective date of the rule to occur after the start of the 2023 control period and consequently expects the 2023 control period to be a transitional period in which the emissions budgets determined in this rulemaking apply only for the portion of the control period occurring on and after the rule's effective date, while any previously determined emissions budgets apply for the portion of the control period before the rule's effective date. The rule's effective date will become known when the rule is published in the **Federal Register**. As soon as practicable thereafter, the EPA will calculate the final prorated or blended 2023 state emissions budgets and 2023 unit-level allocations based on the transitional formulas finalized in this action (see section VI.B.12.a of this document) and will communicate the information to the public through a notice of data availability. The 2023 and 2024 allocations will then be recorded 30 days after the effective date of the final rule (to provide an interval in which to execute the recall of 2023 and 2024 Group 2 allowances, as discussed in section VI.B.12.c of this document), while the 2025 allocations will be recorded by July 1, 2024.[355]

The default unit-level allocations for each control period in 2026 or a later year will be computed immediately following the determination of the state emissions budgets for the control period. The EPA will perform the computations and issue a notice of data availability concerning the preliminary unit-level allocations for each control period by March 1 of the year before the control period. There will be a 30-day period in which objections to the data and preliminary computations may be submitted, and the EPA will then make any appropriate revisions and issue another notice of data availability by May 1 of the year before the control period. The EPA will then record the allocations by July 1 of the year before the control period.[356]

All covered states also have options to establish state-determined allowance allocations for control periods in 2024 and later years. As discussed in section VI.D.1 of this rule, a state choosing to establish state-determined allocations for the 2024 control period would need to submit a letter of intent to the EPA by August 4, 2023, and would need to submit the SIP revision with the allocations by September 1, 2023. The EPA would defer recordation of the 2024 allocations for the state's sources until March 1, 2024, to provide time for this process to be completed. As discussed in sections VI.D.2 and VI.D.3 of this rule, a state choosing to establish state-determined allocations for control periods in 2025 and later years would need to submit a SIP revision by December 1 of the year two years before the first year for which state-determined allocations are being established—*e.g.,* by December 1, 2023, for allocations for the 2025 control period—and would need to submit the allocations for each control period by June 1 of the year before the control period—*e.g.,* by June 1, 2024, for allocations for the 2025

[355] The recordation schedule for the 2023 and 2024 allocations represents an expected acceleration of the recordation schedule in effect immediately before this final rule, which called for allocations of 2023 and 2024 Group 3 allowances to existing units to be recorded by September 1, 2023. *See* Deadlines for Submission and Recordation of Allowance Allocations Under the Cross-State Air Pollution Rule (CSAPR) Trading Programs and the Texas SO_2 Trading Program (the ''Recordation Rule''), 87 FR 52473 (August 26, 2022).

[356] The current recordation schedule, which provides for almost all allowance allocations to existing units for a given control period under all the CSAPR trading programs to be recorded by July 1 of the year before the year of that control period, was adopted in the Recordation Rule.

control period.[357] The EPA would record any state-determined allocations for control periods in 2025 and later years by July 1 of the year before the control period, simultaneously with the recordation of allocations to units in states where the EPA determines the unit-level allocations.

The EPA notes that for the three states with approved SIP revisions establishing their own methodologies for allocating Group 2 allowances—Alabama, Indiana, and New York—the EPA will follow the states' methodologies to the extent possible in developing the EPA's allocations of Group 3 allowances to the units in those states for the control periods in 2023 through 2025.[358] The EPA will not follow any state-specific methodologies as part of the procedures for determining default unit-level allocations of Group 3 allowances for control periods in 2026 or later years. However, like other states, these three states have options to replace the EPA's default allocations with state-determined allocations through SIP revisions starting with the 2024 control period.

As an exception to all of the recordation deadlines that would otherwise apply, the EPA will not record any allocations of Group 3 allowances in a source's compliance account unless that source has complied with the requirements to surrender previously allocated 2023–2024 Group 2 allowances. The surrender requirements are necessary to maintain the previously established levels of stringency of the Group 2 trading program for the states and sources that remain subject to that program under this final rule. The EPA finds that it is reasonable to condition the recordation of Group 3 allowances on compliance with the surrender requirements because the condition will spur compliance and will not impose an inappropriate burden on sources. The EPA considers establishment of this condition, which will facilitate the continued functioning of the Group 2 trading program, to be an appropriate exercise of the Agency's authority under CAA section 301 (42 U.S.C. 7601) to prescribe such regulations as are necessary to carry out its functions under the Act.

The provisions governing allocations to existing units are being finalized substantially as proposed, except for the addition of an additional cap on unit-level allocations in response to comments. The EPA's responses to comments on the unit-level allocation provisions for existing units are in section 5 of the *RTC* document.

c. Allocations From Portions of State Emissions Budgets Set Aside for New Units

The Group 3 trading program regulations provide for the EPA to allocate allowances from each new unit set-aside after the end of the control period at issue. An eligible new unit for purposes of allocations from a set-aside for a given control period is generally any unit in the relevant area that reported emissions subject to allowance surrender requirements during the control period and that was not eligible to receive an allowance allocation as an "existing" unit for the control period. Thus, in addition to units that have not yet completed two full control periods of operation since their monitor certification deadlines, units eligible for allocations from the new unit set-asides may also include existing coal-fired units that first lose their eligibility for allocations from the unreserved portion of the applicable state budget by ceasing operation, and then resume operation in a later control period. The regulations call for the EPA to allocate allowances to any eligible "new" units in the state generally in proportion to their respective emissions during the control period, up to the amounts of those emissions if the relevant set-aside contains sufficient allowances, and not exceeding those emissions. However, in the case of a unit whose allocation for the control period would have been subject to a maximum controlled baseline if the unit was eligible to receive allocations as an existing unit, the unit's allocation from the new unit set-aside will not exceed a cap equal to the unit's reported heat input for the control period times an emissions rate of 0.08 lb/mmBtu.

Any allowances remaining in a new unit set-aside after the allocations to new units are reallocated to the existing units in the state in proportion to those units' previous allocations for the control period as existing units. The EPA issues a notice of data availability concerning the proposed allocations by March 1 following the control period, provides an opportunity for submission of objections, and issues a final notice of data availability and record the allocations by May 1 following the control period, one month before the June 1 compliance deadline.

This EPA notes that the revisions to other provisions of the Group 3 trading program regulations discussed elsewhere in this document will reduce the portions of the state emissions budgets that are allocated through the new unit set-asides. Specifically, because the new unit set-asides will no longer receive any additional allowances when units retire, for control periods in 2025 and later years the amounts of allowances in the new unit set-asides will always be 5 percent of the respective state emissions budgets for the respective control periods. This limit on growth of the new unit set-asides is appropriate given that the number of consecutive control periods for which any particular unit is likely to receive allocations from a state's new unit set-aside will be reduced to two full control periods (and possibly a partial control period before those two control periods) before the unit becomes eligible to receive allocations as an "existing" unit from the unreserved portion of the state's emissions budget. This approach contrasts with the approach under the other CSAPR trading programs where a new unit never becomes eligible to receive allocations from the unreserved portion of the emissions budget and where the new unit set-aside therefore needs to grow to accommodate an ever-increasing share of the state's total emissions.

The EPA also notes that, as discussed in sections VI.D.2 and VI.D.3 of this document, in the event that a state chooses to replace EPA's default allowance allocations under the Group 3 trading program with state-determined allocations through a SIP revision, the EPA will continue to administer the portion of each state emissions budget reserved in a new unit set-aside to ensure the availability of allowance allocations to new units in any areas of Indian country within the state not covered by the state's CAA implementation planning authority.

The final rule's provisions concerning unit-level allocations from the new unit set-asides are unchanged from the proposal except for the addition of the allocation cap in a given control period for any unit that would have been subject to a maximum controlled baseline if the unit was eligible to receive an allocation as an existing unit

[357] The current deadlines for states to submit state-determined allowance allocations to the EPA were adopted in the Recordation Rule and are coordinated with the schedule for computation of state emissions budgets for control periods in 2026 and later years. For example, for the 2026 control period, by May 1, 2025, the EPA will publish the final state emissions budgets and the EPA's default unit-level allocations; by June 1, 2025, states will submit any state-determined unit-level allocations that would replace the default allocations; and by July 1, 2025, the EPA will record the default unit-level allocations or the state-determined unit-level allocations, as applicable, in sources' compliance accounts.

[358] For discussion of how the EPA is using the previously approved allocation methodologies for Alabama, Indiana, and New York to determine allocations to units in these states for the 2023–2025 control periods, see the Allowance Allocation Final Rule TSD.

for that control period.[359] This change was made to address the same comments discussed in section VI.B.9.b of this document that caused the Agency to add the maximum controlled baseline provision to the procedure for allocating allowances to existing units. The Agency did not receive any other comments on the proposed provisions concerning unit-level allocations of allowances from the new unit set-asides.

d. Incorrectly Allocated Allowances

The Group 3 trading program regulations as promulgated in the Revised CSAPR Update include provisions addressing incorrectly allocated allowances. With regard to any allowances that were incorrectly allocated and are subsequently recovered, the provisions as in effect prior to this rule have generally called for the recovered allowances to be reallocated to other units in the relevant state (or Indian country within the borders of the state) through the process for allocating allowances from the new unit set-aside (or Indian country new unit set-aside) for the state. If the procedures for allocating allowances from the set-asides have already been carried out for the control period for which the recovered allowances were issued, the allowances would be allocated through the set-asides for subsequent control periods.

The EPA continues to view the current provisions for disposition of recovered allowances as reasonable in the case of any allowances that are recovered before the deadline for recording allocations of allowances from the new unit set-aside for the control period for which the recovered allowances were issued. However, in the case of any allowances that are recovered after that deadline, adding the recovered allowances to the new unit set-aside for a subsequent control period, as provided in the current regulations, would be inconsistent with the trading program enhancements discussed elsewhere in this document, where the amounts of allowances provided in the state emissions budgets for each control period are designed to reflect the most current available information on fleet composition and utilization and where the quantities of banked allowances available for use in each control period are recalibrated for consistency with the state emissions budgets. The EPA is therefore finalizing revisions to provide that, starting with allowances allocated for the 2024 control period, any incorrectly allocated allowances that are recovered after the deadline for allocating allowances from the new unit set-aside for that control period (*i.e.,* May 1 of the year following the control period) will be transferred to a surrender account instead of being reallocated to other units in the state. The EPA received no comments on this proposed revision, which is being finalized as proposed.

10. Monitoring and Reporting Requirements

The Group 3 trading program requires monitoring and reporting of emissions and heat input data in accordance with the provisions of 40 CFR part 75. Under 40 CFR part 75, a given unit may have several options for monitoring and reporting. Any unit can use CEMS. Qualifying gas- or oil-fired units can use certain excepted monitoring methodologies that rely in part on fuel-flow metering in combination with CEMS-based or testing-based NO_X emissions rate data. Certain non-coal-fired, low-emitting units can use a low mass emissions (LME) methodology, and sources can seek approval of alternative monitoring systems approved by the Administrator through a petition process. Each CEMS must undergo rigorous initial certification testing and periodic quality assurance testing thereafter, including the use of relative accuracy test audits and 24-hour calibrations. In addition, when a monitoring system is not operating properly, standard substitute data procedures are applied to produce a conservative estimate of emissions for the period involved. Further, 40 CFR part 75 requires electronic submission of quarterly emissions reports to the Administrator, in a format prescribed by the Administrator. The quarterly reports will contain all the data required concerning ozone season NO_X emissions under the Group 3 trading program.

In this rulemaking, as proposed, the EPA is making two changes to the Group 3 trading program's previous requirements related to monitoring, recordkeeping, and reporting. First, the EPA is revising the monitor certification deadline in the Group 3 trading program regulations applicable to certain units that have not already certified monitoring systems for use under 40 CFR part 75. This revision is expected to provide approximately 15 EGUs in Nevada and Utah with 180 days following the rule's effective date to certify monitoring systems, with the consequence that the units are expected to become subject to allowance holding requirements under the Group 3 trading program starting with the 2024 control period. Second, to implement the trading program enhancements, the EPA is adding certain new recordkeeping and reporting requirements, which will be implemented through amendments to the regulations in 40 CFR part 75 and will apply starting January 1, 2024. Sources generally will be able to meet the additional recordkeeping and reporting requirements using the data that are already collected by their current monitoring systems, and the EPA is not requiring the installation of additional monitoring systems at any source. However, a small number of sources with common stacks could find it advantageous to upgrade their monitoring systems so as to monitor at the individual units instead of monitoring at the common stack. The Group 3 trading program monitor certification deadline revisions and the additional recordkeeping and reporting requirements are discussed in sections VI.B.10.a and VI.B.10.b, respectively.[360]

a. Monitor Certification Deadlines

In general, a unit subject to the Group 3 trading program must monitor and report emissions data using certified monitoring systems starting as of the date the unit enters the trading program or, if later, 180 days after the unit commences commercial operation. Where an EGU has already certified and maintained monitoring systems in accordance with 40 CFR part 75 for purposes of another trading program, no recertification solely for purposes of entering the Group 3 trading program is required. Under these pre-existing provisions of the Group 3 trading program regulations, nearly all currently operating EGUs transitioning to the trading program under this rule are positioned to begin monitoring and reporting under the trading program as of their dates of entry (or if later, 180 days after they commence commercial operation) because of the units' previous requirements to monitor and report emissions under other programs including the CSAPR NO_X Ozone Season Group 2 Trading Program (for

[359] As discussed in section IX.B of this rule, the EPA is relocating some of the regulatory provisions relating to administration of the new unit set-asides and is also removing certain provisions that are made obsolete by revisions to other provisions of the Group 3 trading program regulations.

[360] The EPA is not amending the existing provisions of the Group 3 trading program regulations that govern whether units covered by the program must record and report required data on a year-round basis or may elect to record and report required data on an ozone season-only basis. *See* 40 CFR 97.1034(d)(1); *see also* 40 CFR 75.74(a)-(b). Thus, for units that are required or elect to report other data on a year-round basis, the additional recordkeeping and reporting requirements will also apply year-round, while for units that are allowed and elect to report other data on an ozone season-only basis, the additional requirements will also apply for the ozone season only.

units in Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin), the CSAPR NO_X Annual Trading Program (for units in Minnesota), and the Acid Rain Program (for most units in Nevada and Utah).

As discussed in section VI.B.3 of this document, the EPA has identified 15 potentially affected units in Nevada and Utah that commenced commercial operation more than 180 days before the effective date of this rule and that do not currently report emissions data to the Agency under 40 CFR part 75.[361] To ensure that units in this situation have sufficient time to certify monitoring systems as required under this rule, the final rule establishes a monitoring certification deadline of 180 days after the effective date of the rule for affected units that are not already required to report emissions under 40 CFR part 75 under another program, equivalent to the 180-day window already provided to units commencing commercial operation after (or less than 180 days before) the final rule's effective date. The 180th day for units in this situation will likely fall after the end of the 2023 ozone season, with the result that the certification deadline will be extended until May 1, 2024, the first day of the 2024 ozone season. Because the Group 3 trading program's allowance holding requirements apply to a given unit only after that unit's monitor certification deadline, the units in this situation consequently will become subject to allowance holding requirements as of the 2024 ozone season rather than the 2023 ozone season.

The EPA received no comments on the provisions establishing a monitor certification deadline 180 days after the effective date of this rule for affected units that are not already required to report emissions under 40 CFR part 75, and the provisions are being finalized as proposed.

b. Additional Recordkeeping and Reporting Requirements

To facilitate implementation of the backstop daily NO_X emissions rates for certain coal-fired units, the secondary emissions limitations for units contributing to assurance level exceedances, and the revised default unit-level allowance allocation procedures, the final rule amends 40 CFR part 75 to establish two sets of additional recordkeeping and reporting requirements. The first set of additional recordkeeping and reporting requirements is specific to the backstop daily emissions rate provisions. Starting January 1, 2024, units listing coal as a fuel in their monitoring plans, serving generators of 100 MW or larger, and equipped with SCR controls on or before the end of the previous control period (except circulating fluidized bed units) will be required to record and report total daily NO_X emissions and total daily heat input, daily average NO_X emissions rate, and daily NO_X emissions exceeding the backstop daily NO_X emissions rate. The units will also be required to record and report cumulative NO_X emissions exceeding the backstop daily NO_X emissions rate for the ozone season and any portion of such cumulative NO_X emissions exceeding 50 tons. Starting January 1, 2030, the same recordkeeping and reporting requirements will apply to all units listing coal as a fuel in their monitoring plans and serving generators of 100 MW or larger (except circulating fluidized bed units), including units not equipped with SCR controls. These data will be used to determine the allowance surrender requirements related to the backstop daily NO_X emissions rates. Implementation of these additional recordkeeping and reporting requirements would necessitate a one-time update to the units' data acquisition and handling systems but would not require any changes to the monitoring systems already needed to meet other requirements under 40 CFR part 75.

The second type of additional recordkeeping and reporting requirements applies to units exhausting to common stacks. For these units, 40 CFR part 75 includes options that often allow monitoring to be conducted at the common stack on a combined basis for all the units as an alternative to installing separate monitoring systems for the individual units in the ductwork leading to the common stack. The units then keep records and report hourly and cumulative NO_X mass emissions and in many cases heat input data on a combined basis for all units exhausting to the common stack. With respect to heat input data, but not NO_X mass emissions data, most such units have also been required historically to record and report hourly and cumulative data on an individual-unit basis, and where necessary they typically have computed the necessary unit-level hourly heat input values by apportioning the combined hourly heat input values for the common stack in proportion to the individual units' recorded hourly output of electricity or steam. *See generally* 40 CFR 75.72.

In this rulemaking, the provisions governing default unit-level allowance allocations, backstop daily NO_X emissions rates for certain coal-fired units, and secondary emissions limitations for units contributing to assurance level exceedances all require the use of unit-level reported data on NO_X mass emissions (or unit-level NO_X emissions rates computed in part based on unit-level reported data on NO_X mass emissions). To facilitate the implementation of these provisions, the final rule requires all units covered by the Group 3 trading program exhausting to common stacks to record and report unit-level hourly and cumulative NO_X mass emissions data starting January 1, 2024. To obtain the necessary unit-level hourly mass emissions values, the revised regulations rule allow the units to apportion hourly mass emissions values determined at the common stack in proportion to the individual units' recorded hourly heat input. The apportionment procedure is very similar to the apportionment procedure that most such units already apply to compute reported unit-level heat input data. Where sources choose to obtain the additional required data values through apportionment, implementation of the additional recordkeeping and reporting requirements will necessitate a one-time update to the units' data acquisition and handling systems but will not require any changes to the monitoring systems already needed to meet other requirements under 40 CFR part 75.

For most units sharing common stacks, the EPA expects that the reported unit-specific hourly NO_X emissions values computed through the apportionment procedures will reasonably approximate the values that could be obtained through installation and operation of separate monitoring systems for the individual units, because the units exhausting to the common stack would be expected to have similar NO_X emissions rates. However, the EPA also recognizes that at some plants, particularly those where SCR-equipped and non-SCR-equipped coal-fired units share a common stack, unit-level values determined through apportionment based on electricity or steam output could overstate the reported NO_X mass emissions for the SCR-equipped units and correspondingly understate the reported NO_X mass emissions for the non-SCR-equipped units.[362] As proposed, the

[361] The units are listed in Table VI.B.3–1.

[362] The EPA is aware of five plants in the states covered by this rule where SCR-equipped and non-SCR-equipped coal-fired units exhaust to a common stack: Clifty Creek in Indiana; Cooper, Ghent, and Shawnee in Kentucky; and Sammis in Ohio. The owners of the Sammis plant have announced plans to retire the plant in 2023.

final rule leaves in place the existing options under 40 CFR part 75 for plants to upgrade their monitoring equipment to monitor on a unit-specific basis instead of at the common stack. Plant owners may find this option attractive if they believe it would reduce the quantities of reported emissions exceeding the backstop daily emissions rate.

The EPA is finalizing the additional recordkeeping and reporting requirements generally as proposed, with modifications as needed to accommodate the changes in the backstop daily emissions rate provisions from proposal discussed in sections VI.B.1.c.i and VI.B.1.7. No comments were received on the recordkeeping and reporting requirements added to facilitate implementation of the backstop daily emissions rate. Comments on the requirement to report unit-specific NO_X emissions data for units sharing common stacks are addressed in the following paragraphs.

Comment: Some commenters claimed that for plants where SCR-equipped and non-SCR-equipped coal-fired units share common stacks, the rule as proposed would have effectively mandated installation of unit-specific monitoring systems in order to comply with the backstop daily emissions rate provisions. The commenters generally requested that application of the backstop daily rate provisions be delayed for plants with common stacks until all units sharing the stacks were subject to the provisions. Alternatively, they claimed that the EPA should consider the cost of the additional unit-specific monitoring system to be a cost of the rule.

One commenter claimed that the option to install unit-specific monitoring systems for the units sharing a common stack at its plant was not feasible because of a lack of locations in the units' ductwork suitable for installation of the monitoring equipment. Specifically, the commenter claimed that EPA Method 1 requires monitoring equipment to be located at least eight duct diameters downstream and two duct diameters upstream of any flow disturbance and stated that the units had no straight runs of ductwork sufficiently long to meet these criteria.

Response: The EPA's response to comments about the application of backstop rate requirements to units sharing common stacks is in section VI.B.7 of this document. With respect to assertions that the rule effectively mandates installation of unit-specific monitoring systems, the EPA disagrees. Although the EPA pointed out the option in the proposal, anticipating that owners of some units sharing common stacks might find it advantageous to upgrade their monitoring systems, the final rule does not mandate such upgrades and explicitly provides a reporting option that can be used if a plant owner continues to monitor only at the common stack. For example, a plant owner might choose not to upgrade monitoring systems if the owner does not plan to operate the non-SCR-equipped units sharing the stack frequently. Regarding the contention that the cost of additional monitoring systems should be considered a cost of the rule, the EPA notes that the monitoring cost estimates that the Agency regularly develops for 40 CFR part 75 already reflect the conservative assumption that all affected units perform monitoring on a unit-specific basis.

With respect to the comment asserting an inability to install unit-specific monitoring equipment because of a lack of suitable locations, the EPA does not believe the commenter has provided sufficient information to support the assertion. Although the commenter cites the EPA Method 1 location criteria, the CEMS location provisions in 40 CFR part 75 do not reference those location criteria but instead reference the EPA Performance Specification 2 location criteria, which recommend that a CEMS be located at least two duct diameters downstream and a half duct diameter upstream from a point at which a change in pollutant concentration may occur.[363] Thus, while the commenter states that its units do not have straight runs of ductwork ten duct diameters long, the relevant siting criteria actually call for straight runs of ductwork only 2.5 duct diameters long, and the commenter has not provided information indicating that these criteria could not be met. Moreover, even EPA Method 1 does not require monitoring equipment to be located eight duct diameters upstream and two duct diameters downstream of any flow disturbance. While the method recommends those distances as the first option, the method also allows for locations two duct diameters upstream and a half duct diameter upstream from any flow disturbance, as well as other locations if certain performance criteria can be met.[364]

[363] Appendix B to 40 CFR part 60, Performance Specification 2, sec. 8.1.2; *see also* appendix A to 40 CFR part 75, section 1.1.

[364] Appendix A–1 to 40 CFR part 60, Method 1, sec. 11.1.

11. Designated Representative Requirements

As noted in section VI.B.1.a of this document, a core design element of all the CSAPR trading programs is the requirement that each source must have a designated representative who is authorized to represent all of the source's owners and operators and is responsible for certifying the accuracy of the source's reports to the EPA and overseeing the source's Allowance Management System account. The necessary authorization of a designated representative is certified to the EPA in a certificate of representation.

The existing designated representative provisions in the Group 3 trading program regulations already provide that the EPA will interpret references to the Group 2 trading program in certain documents—including a certificate of representation as well as a notice of delegation to an agent or an application for a general account—as if the documents referenced the Group 3 trading program instead of the Group 2 trading program. For these reasons, sources that have participated in the Group 2 trading program and that are transitioning to the Group 3 trading program under this rule will not need to submit any new forms as part of the transition, because previously submitted forms will be valid for purposes of the Group 3 trading program.

For a source that is newly affected under the Group 3 trading program and that is not currently affected under the Group 2 trading program, a designated representative who has been duly authorized by the source's owners and operators must submit a new or updated certificate of representation to the EPA. The EPA will not record any Group 3 allowances allocated to a source in the source's compliance account until a certificate of representation has been submitted for the source. If a source is also affected under other CSAPR trading programs or the Acid Rain Program, the same individual must be the source's designated representative for purposes of all the programs.

The EPA did not propose and is not finalizing any changes to the designated representative requirements. The EPA received no comments on the provisions of the proposal relating to these requirements.

12. Transitional Provisions

This section discusses several provisions that the EPA will implement to address the transition of sources into the Group 3 trading program as revised. The purposes of the transitional provisions are generally the same as the purposes of the analogous transitional provisions promulgated in the Revised CSAPR Update: first, addressing the likelihood that the effective date of this rule will fall after the starting date of the first affected ozone season (which in this case is, May 1, 2023); second, establishing an appropriately-sized initial allowance bank through the conversion of previously banked allowances; and third, preserving the intended stringency of the Group 2 trading program for the sources that will continue to be subject to that program.[365] However, the sources that will be participants in the revised Group 3 trading program under this rule are transitioning from several different starting points—with some sources already in the existing Group 3 trading program, some sources coming from the Group 2 trading program, and some sources not currently participating in any seasonal NO_X trading program. The EPA is therefore finalizing transitional provisions that differ across the sets of potentially affected sources based on the sources' different starting points.

a. Prorating Emissions Budgets, Assurance Levels, and Unit-Level Allowance Allocations in the Event of an Effective Date After May 1, 2023

The EPA expects that the effective date of this rule will fall after the start of the Group 3 trading program's 2023 control period on May 1, 2023, because the effective date of the rule will be 60 days after the date of the final rule's publication in the **Federal Register**. The EPA is addressing this circumstance by determining the amounts of emissions budgets and unit-level allowance allocations on a full-season basis in the rulemaking and by also including provisions in the revised regulations to prorate the full-season amounts as needed to ensure that no sources become subject to new or more stringent regulatory requirements before the final rule's effective date.[366] Variability limits, assurance levels, and unit-level allocations for 2023 will all be computed using the appropriately prorated emissions budgets amounts.[367]

As discussed in section VI.B.2 of this document, in the case of the three states (and Indian country within the states' borders) whose sources do not currently participate in either the Group 2 trading program or the Group 3 trading program—Minnesota, Nevada, and Utah—the sources will begin participating in the Group 3 trading program on the later of May 1, 2023, or the rule's effective date. For these states, in the rulemaking the EPA has computed the full-season emissions budgets that would have applied for the entire 2023 control period if the final rule had become effective no later than May 1, 2023, and were therefore in effect for the entire 153-day control period from May 1, 2023, through September 30, 2023. Assuming that the final rule becomes effective after May 1, 2023, as expected, the EPA will determine prorated emissions budgets for the 2023 control period by multiplying each full-season emissions budget by the number of days from the rule's effective date through September 30, 2023, dividing by 153 days, and rounding to the nearest allowance. The prorated variability limits for the 2023 control period will be computed by first determining for each state the percentage by which the state's reported heat input for the full 2023 ozone season (*i.e.,* May 1, 2023 through September 30, 2023) exceeds the heat input used to compute the state's full-season 2023 emissions budget under this rule and then multiplying the higher of this percentage or 21 percent by the state's prorated emissions budget and rounding to the nearest allowance, yielding prorated assurance levels that equal a minimum of 121 percent of the prorated emissions budgets. To determine unit-level allocation amounts from the prorated emissions budgets, the EPA will apply the unit-level allocation procedure described in section VI.B.9 to the prorated budgets. All calculations required to determine the prorated emissions budgets, the minimum 21 percent variability limits, and the unit-level allocations for the 2023 control period will be carried out as soon as possible after the EPA learns the rule's effective date. The unit-level allocations for both the 2023 and 2024 control periods will be recorded in facilities' compliance accounts approximately 30 days after the rule's effective date, as discussed in section VI.B.9.b of this document.

In the case of the states (and Indian country within the states' borders) whose sources currently participate in the Group 3 trading program—Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia—the sources will continue to participate in the Group 3 trading program for the 2023 control period, subject to prorating procedures designed to ensure that the changes in 2023 emissions budgets and assurance levels will not substantively affect the sources' requirements prior to the rule's effective date. For these states, in the rulemaking the EPA has computed the full-season emissions budgets that would have applied for the entire 2023 control period if the final rule had become effective no later than May 1, 2023, but the EPA has also retained in the regulations the full-season emissions budgets for the 2023 control period that were established in the Revised CSAPR Update rulemaking. The EPA has added a provision to the regulations indicating that the emissions budgets promulgated in the Revised CSAPR Update will apply on a prorated basis for the portion of the 2023 control period before the final rule's effective date and the emissions budgets established in this rulemaking will apply on a prorated basis for the portion of the 2023 control period on and after the final rule's effective date. Under this provision, the EPA will determine a blended emissions budget for each state for the 2023 control period, computed as the sum of the appropriately prorated amounts of the state's previous and revised emissions budgets. (For example, if the final rule becomes effective on the eleventh day of the 153-day 2023 control period, the blended emissions budget will equal the sum of 10/153 times the previous emissions budget plus 143/153 times the revised emissions budget, rounded to the nearest allowance.) Blended variability limits for the 2023 control period will be computed by first determining for each state the percentage by which the state's reported heat input for the full 2023 ozone season exceeds the heat input used to compute the state's full-season 2023 emissions budget under this rule and then multiplying the higher of this percentage or 21 percent by the state's prorated emissions budget and rounding to the nearest allowance,

[365] As discussed in section VI.B.1.d, the EPA is not creating a ''safety valve'' mechanism in this rule analogous to the voluntary supplemental allowance conversion mechanism established under the Revised CSAPR Update, but intends in the near future to propose and take comment on potential amendments to the Group 3 trading program that would add an auction mechanism to the regulations for the purpose of further increasing allowance market liquidity in conjunction with other appropriate changes to ensure program stringency is maintained. While these changes may provide an additional measure of assurance to the market that allowances will be available for compliance to a degree consistent with the Step 3 emissions control stringency, the EPA does not anticipate that market liquidity concerns pose a challenge to the feasibility of sources to comply with the Group 3 trading program as finalized in this action.

[366] As discussed in sections VI.B.7 and VI.B.8, the revisions establishing unit-specific backstop daily emissions rates and, for units contributing to assurance level exceedances, secondary unit-specific emissions limitations, will not take effect until the 2024 control period or later.

[367] The EPA notes that transitional provisions similar to the prorating provisions being finalized in this rule were finalized and implemented without issue under the Revised CSAPR Update.

yielding blended assurance levels that equal a minimum of 121 percent of the blended emissions budgets. Unit-level allocations will be determined by applying the allocation procedure described in section VI.B.9 to the blended budgets. Again, all calculations required to determine the prorated emissions budgets, the minimum 21 percent variability limits, and the unit-level allocations for the 2023 control period will be carried out as soon as possible after the EPA learns the effective date of this rule. The unit-level allocations for both the 2023 and 2024 control periods will be recorded in facilities' compliance accounts approximately 30 days after the final rule's effective date, as discussed in section VI.B.9.b of this document.

In the case of the states (and Indian country within the states' borders) whose sources currently participate in the Group 2 trading program—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin—the sources will begin to participate in the Group 3 trading program as of May 1, 2023, regardless of the rule's effective date, as discussed in section VI.B.2 of this document, subject to prorating procedures designed to ensure that the transition from the Group 2 trading program to the Group 3 trading program will not substantively affect the sources' requirements prior to the rule's effective date. The prorating procedures for these states mirror the procedures for the states currently in the Group 3 trading program, except that because no emissions budgets currently appear in the Group 3 trading program regulations for the states that are currently covered by the Group 2 trading program, the EPA has added two sets of emissions budgets for these states to the Group 3 trading program regulations: first, the states' emissions budgets for the 2023 control period that currently appear in the Group 2 trading program regulations, which are being included in the revised Group 3 trading program regulations to represent the states' emissions budgets for the portion of the 2023 control period before the rule's effective date, and second, the emissions budgets for the 2023 control period established for the states in this rulemaking, which are being included in the revised Group 3 trading program regulations to represent the state's emissions budgets for the portion of the 2023 control period on and after the rule's effective date. The procedures and timing for determining blended emissions budgets, variability limits and assurance levels, and unit-level allowance allocations, as well as the timing for the recordation of unit-level allocations, are the same as for the states currently in the Group 3 trading program.

Beginning administrative implementation of the Group 3 trading program starting on May 1, 2023, for sources currently in the Group 2 trading program imposes no new or different requirements on these sources. It would serve the public interest and greatly aid in administrative efficiency for most elements of the Group 3 trading program—specifically, all elements of the trading program other than the elements designed to establish more stringent emissions limitations for the sources coming from the Group 2 trading program—to apply to the sources starting on May 1, 2023. This is how the EPA handled the earlier transition of twelve states from the Group 2 to the Group 3 trading program in the Revised CSAPR Update, which was accomplished successfully and without incident. *See* 86 FR 23133–34. This approach would facilitate implementation of the Group 3 trading program in an orderly manner for the entire 2023 ozone season and reduce compliance burdens and potential confusion. Each of the CSAPR trading programs for ozone season NO_X is designed to be implemented over an entire ozone season. Implementing the transition from the Group 2 trading program to the Group 3 trading program in a manner that required the covered sources to participate in the Group 2 trading program for part of the 2023 ozone season and the Group 3 trading program for the remainder of that ozone season would be complex and burdensome for sources. Attempting to address the issue by splitting the Group 2 and Group 3 requirements for these sources into separate years is not a viable approach, because the EPA has no legal basis for releasing the transitioning Group 2 sources from the emissions reduction requirements found to be necessary in the CSAPR Update for a portion of the 2023 ozone season, and the EPA similarly has no legal basis for deferring implementation of the 2023 emissions reduction requirements found to be necessary under this rule for the transitioning Group 2 sources until 2024. Moreover, the requirements of the current Group 2 trading program and the revised Group 3 trading program for the 2023 control period are substantively identical as to almost all provisions, such that with respect to those provisions, a source will not need to alter its operations in any manner or face different compliance obligations as a consequence of a transition from the Group 2 trading program to the Group 3 trading program. Thus, the EPA believes that no substantive concerns regarding retroactivity arise from transitioning the sources currently in the Group 2 trading program to the Group 3 trading program starting on May 1, 2023, as long as those aspects of the revised Group 3 trading program for the 2023 control period that *do* meaningfully differ from the analogous aspects of the Group 2 trading program—that is, the relative stringencies of the two trading programs, as reflected in the emissions budgets and associated assurance levels—are applied only as of the effective date of the final rule.

In all respects other than prorating the emissions budgets, variability limits and assurance levels, and unit-level allowance allocations, with respect to the sources currently participating in the Group 2 trading program or the Group 3 trading program, the EPA will implement the revised Group 3 trading program for the 2023 control period in a uniform manner for the entire control period. Thus, emissions will be monitored and reported for the entire 2023 ozone season (*i.e.,* May 1, 2023, through September 30, 2023), and as of the allowance transfer deadline for the 2023 control period (*i.e.,* June 1, 2024) each source will be required to hold in its compliance account vintage-year 2023 Group 3 allowances not less than the source's emissions of NO_X during the entire 2023 ozone season. Any efforts undertaken by one of these sources to reduce its emissions during the portion of the 2023 ozone season before the effective date of the rule will aid the source's compliance by reducing the amount of Group 3 allowances that the source would need to hold in its compliance account as of the allowance transfer deadline, increasing the range of options available to the source for meeting its compliance obligations under the revised Group 3 trading program.

In the case of the sources in the three states that do not currently participate in the Group 2 trading program or the Group 3 trading program, the 2023 control period will begin on the effective date of the rule, and because the effective date of the rule is expected to fall after May 1, 2023, the 2023 control period for the sources in these states will be shorter than the 153-day length of the 2023 control period for the sources in the remaining states. However, the EPA similarly will implement the revised Group 3 trading program for the sources in these states in a uniform manner for the entire shorter control period.

The prorating provisions are being finalized as proposed. The EPA received no comments on the portion of the proposal discussing these provisions.

b. Creation of Additional Group 3 Allowance Bank for 2023 Control Period

In the CSAPR Update, where the EPA established the Group 2 trading program and transitioned over 95 percent of the sources that had been participating in what is now the CSAPR NO_X Ozone Season Group 1 Trading Program (the ''Group 1 trading program'') to the new program, the EPA determined that it was reasonable to establish an initial bank of allowances for the Group 2 trading program by converting almost all allowances banked under the Group 1 trading program at a conversion ratio determined by a formula. In the Revised CSAPR Update, where the EPA established the Group 3 trading program and transitioned approximately 55 percent of the sources that had been participating in the Group 2 trading program to the new program, the EPA similarly determined that it was reasonable to provide for an initial bank of allowances for the Group 3 trading program by converting allowances banked under the Group 2 trading program at a conversion ratio determined by a formula, using a conversion procedure that was modified to leave much of the Group 2 allowance bank available for use by the approximately 45 percent of sources then in the Group 2 trading program that would remain in that program. Any conversion of banked allowances from a previous trading program for use in a new trading program must ensure that implementation of the new trading program will result in NO_X emissions reductions sufficient to address significant contribution by all states that would be participating in the new trading program, while also providing industry certainty (and obtaining an environmental benefit) through continued recognition of the value of saving allowances through early reductions in emissions. The EPA's approach to balancing these concerns in the CSAPR Update through the conversion of banked allowances from the Group 1 trading program to the Group 2 trading program was upheld in *Wisconsin* v. *EPA,* 938 F.3d at 321.

Under this final rule, applying the same balancing principle as in the CSAPR Update and the Revised CSAPR Update, the EPA will carry out a further conversion of allowances banked for control periods before 2023 under the Group 2 trading program into allowances usable in the Group 3 trading program in control periods in 2023 and later years. Because the EPA is transitioning over 80 percent of the remaining sources in the Group 2 trading program to the Group 3 trading program—much closer to the situation in the CSAPR Update than the situation in the Revised CSAPR Update—in this rule the EPA is applying a conversion procedure similar to the procedure followed in the CSAPR Update. Under the conversion procedure in this rule, the EPA has not set a predetermined conversion ratio in the regulations (as was done in the Revised CSAPR Update) but instead has established provisions identifying the target amount of new Group 3 allowances that will be created and defining the types of accounts whose holdings of Group 2 allowances will be converted to Group 3 allowances (as was done in the CSAPR Update). The conversion date will be carried out by September 18, 2023, which is expected to be approximately 2 months after the compliance deadline for the 2022 control period under the Group 2 trading program and approximately ten months before the compliance deadline for the 2023 control period under the Group 3 trading program. The actual conversion ratio will be determined as of the conversion date and will be the ratio of the total amount of Group 2 allowances held in the identified types of accounts prior to the conversion to the total amount of Group 3 allowances being created.

With respect to the numerator of the conversion ratio—that is, the total amount of Group 2 allowances being converted—the EPA has defined the types of accounts included in the conversion to include all accounts except the facility accounts of sources in states that will remain in the Group 2 trading program, consistent with the approach taken in the CSAPR Update.[368] Thus, the accounts whose holdings of Group 2 allowances will be converted to Group 3 allowances will include (1) the facility accounts of all sources in the states transitioning from the Group 2 trading program to the Group 3 trading program, (2) the facility accounts of all sources in the states already participating in the Group 3 trading program, (3) the facility accounts of all sources in any other states not covered by the Group 2 trading program that happen to hold Group 2 allowances as of the conversion date, and (4) all general accounts (that is, accounts that are not facility accounts, including other accounts controlled by source owners as well as accounts controlled by non-source entities such as allowance brokers). Creating the new Group 3 allowances through conversion of previously banked Group 2 allowances will also help preserve the stringency of the Group 2 trading program for the states that remain covered by that trading program at levels consistent with the stringency found to be appropriate to address those states' good neighbor obligations with respect to the 2008 ozone NAAQS in the CSAPR Update.

With respect to the denominator of the conversion ratio—that is, the target amount of Group 3 allowances that will be created in the conversion process—the EPA has followed the same approach for setting the target amount that was used in the Revised CSAPR Update for creation of the initial Group 3 allowance bank. Specifically, the target amount of Group 3 allowances to be created in this rule will be computed as the sum of the minimum 21 percent variability limits for the 2024 control period[369] established for the ten states being added to the Group 3 trading program, prorated to reflect the portion of the 2023 control period occurring on and after the effective date of the final rule. Based on the amounts of the state emissions budgets and variability limits, the full-season target amount for the conversion would be 23,094 Group 3 allowances. The quantity of banked Group 2 allowances currently held in accounts other than the facility accounts of sources in Iowa, Kansas, and Tennessee exceeding the quantity of allowances likely to be needed for 2022 compliance is approximately 149,386 allowances. Thus, if the quantities of banked Group 2 allowances held in the accounts being included in the conversion do not change between now and the conversion date, and if there was no prorating adjustment, the conversion ratio would be approximately 6.5-to-1, meaning that one Group 3 allowance would be created for every 6.5 Group 2 allowances deducted in the conversion process.[370]

As noted in section VI.B.12.a of this document, the EPA expects that the effective date of this rule will occur after

[368] The states whose sources will continue to participate in the Group 2 trading program for the 2023 control period will be Iowa, Kansas, and Tennessee.

[369] Similar to the approach taken in the Revised CSAPR Update, because emissions reductions from some of the emissions controls that EPA has identified as appropriate to use in setting budgets are first reflected in the 2024 state budgets rather than the 2023 state budgets, the EPA is basing the bank target amount on the sum of the states' 2024 variability limits rather than the 2023 variability limits.

[370] By comparison, the analogous conversion ratio under the Revised CSAPR Update was 8-to-1.

the start of the 2023 ozone season, and prorating provisions are being promulgated in this rule to ensure that the increased stringency of this rule's state budgets and state assurance levels (*i.e.,* the sums of the budgets and variability limits) will take effect only after the rule's effective date. Consistent with these other procedures, the EPA will similarly prorate the bank target amount used in the conversion process. For example, if the effective date of the final rule is the eleventh day of the 153-day 2023 ozone season, the full-season initial bank target amount of 23,094 allowances would be prorated to an initial bank target amount of 21,585 allowances.[371] The EPA notes that prorating the bank amount in this manner will not reduce sources' compliance flexibility for the 2023 ozone season, because the amounts of Group 3 allowances that sources will receive for the portion of the 2023 ozone season before the rule's effective date will be based on the trading program budgets for the 2023 control period that were in effect before this rulemaking. These trading program budgets exceed the sources' collective 2022 emissions by approximately 29,789 tons, indicating potentially surplus allowances roughly 1.3 times the full-season bank conversion target amount of 23,094 allowances. Thus, although the prorating procedure will reduce the amount of Group 3 allowances that would be available to sources in the form of an initial bank, the reduction in the quantity of these allowances will be more than offset by the quantities of Group 3 allowances that will be allocated in excess of sources' recent historical emissions levels for the portion of the ozone season before the final rule's effective date.

As in the CSAPR Update and the Revised CSAPR Update, the EPA's overall objective in establishing the target amount for the allowance conversion is to achieve a total target amount for the bank at a level high enough to accommodate year-to-year variability in operations and emissions, as reflected in states' variability limits, but not high enough to allow sources collectively to plan to emit in excess of the collective state budgets. The EPA believes that a well-established trading program should be able to function with an allowance bank lower than the full amount of the covered states' variability limits, as discussed in section VI.B.6 of this document with respect to the bank recalibration process that will begin with the 2024 control period. However, the EPA also believes there are several compelling reasons in this instance to use a bank target higher than the minimum practicable level.

First, making an allowance bank available for use in the 2023 control period that is somewhat higher than the minimum practicable level will help to address concerns that might otherwise arise regarding the transition to a new set of compliance requirements, for some sources, and the transition to compliance requirements based on revised emissions budgets different from the emissions budgets that the sources had reason to anticipate under previous rulemakings, for the remaining sources. Although the EPA is confident that the emissions budgets being established in this rulemaking for the 2023 control period are readily achievable, the EPA also believes that the existence of a somewhat larger allowance bank at this transition point will promote sources' confidence in their ability to meet their 2023 compliance obligations in general and in a liquid allowance market in particular. Second, because the large majority of the remaining Group 2 allowances that will be converted to Group 3 allowances in this rulemaking are held by the sources currently in the Group 2 trading program, while the large majority of the initial bank of Group 3 allowances previously created in the conversion under the Revised CSAPR Update are held by the sources already in the Group 3 trading program, basing the conversion in this rulemaking on a target bank amount set in the same manner as the target bank amount used in the Revised CSAPR Update is expected to result in a less concentrated distribution of holdings of banked Group 3 allowances following the conversion than would be the case if a more stringent target bank amount were used under this rulemaking than was used in the Revised CSAPR Update. A lower concentration of holdings of banked Group 3 allowances would generally be expected to help ensure allowance market liquidity. Third, the EPA considers it equitable to treat the sources in the states transitioning from the Group 2 trading program to the Group 3 trading program in this rulemaking roughly similarly to the sources in the states that transitioned between the same two trading programs in the Revised CSAPR Update with respect to the benefit they would receive under the Group 3 trading program for any efforts they may have made to make emissions reductions under the Group 2 trading program beyond the minimum efforts that were required to comply with the emissions budgets under that program. Finally, to the extent that the conversion results in a larger bank of allowances remaining after the 2023 control period than is considered necessary to sustain a well-functioning trading program in subsequent control periods, the excess will be removed from the program in the bank recalibration process that will be implemented starting with the 2024 control period and therefore will not weaken sources' incentives to control emissions on a permanent basis.

The rule's provisions relating to the creation of an incremental Group 3 allowance bank are being finalized as proposed. Comments on the creation of the incremental allowance bank are discussed in section 5 of the *RTC.*

c. Recall of Group 2 Allowances Allocated for Control Periods After 2022

To maintain the previously established levels of stringency of the Group 2 trading program for the states and sources that remain subject to that program, the EPA is recalling CSAPR NO_X Ozone Season Group 2 allowances equivalent in amount and usability to all vintage year 2023–2024 CSAPR NO_X Ozone Season Group 2 allowances previously allocated to sources in states and areas of Indian country transitioning to the Group 3 trading program and recorded in the sources' compliance accounts. The recall provisions apply to all sources in jurisdictions newly added to the Group 3 trading program in whose compliance accounts CSAPR NO_X Ozone Season Group 2 allowances for a control period in 2023 or 2024 were recorded, including sources where some or all units have permanently retired or where the previously recorded 2023–2024 allowances have been transferred out of the compliance account. The recall provisions provide a flexible compliance schedule intended to accommodate any sources that have already transferred the previously recorded 2023–2024 allowances out of their compliance accounts and allow Group 2 allowances of earlier vintages to be surrendered to achieve compliance. Like the similar recall provisions finalized in the Revised CSAPR Update, the recall provisions include specifications for how the recall provisions apply in instances where a source and its allowances have been transferred to different parties and for the procedures that the EPA will follow to implement the recall.

Under the Group 2 trading program regulations, each Group 2 allowance is a ''limited authorization to emit one ton of NO_X during the control period in one year,'' where the relevant limitations include the EPA Administrator's

[371] 23,094 × (153 − 10) ÷ 153 = 21,585.

authority ''to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.'' 40 CFR 97.806(c)(6)(ii). The Administrator is determining that, to effectively implement the Group 2 trading program as a compliance mechanism through which states not subject to the Group 3 trading program may continue to meet their obligations under CAA section 110(a)(2)(D)(i)(I) with regard to the 2008 ozone NAAQS, it is necessary to limit the use of Group 2 allowances equivalent in quantity and usability to all Group 2 allowances previously allocated for the 2023–2024 control periods and recorded in the compliance accounts of sources in the newly added Group 3 jurisdictions. The Group 2 allowances that have already been allocated to sources in the newly added Group 3 states for the 2023–2024 control periods and recorded in the sources' compliance accounts represent the substantial majority of the total remaining quantity of Group 2 allowances that have been allocated and recorded for the 2023–2024 control periods and that were not already made subject to recall when other jurisdictions were transferred from the Group 2 trading program to the Group 3 trading program in the Revised CSAPR Update. Because allowances can be freely traded, if the use of the 2023–2024 Group 2 allowances previously recorded in newly added Group 3 sources' compliance accounts (or equivalent Group 2 allowances) were not limited, the effect would be the same as if the EPA had issued to sources in the states that will remain covered by the Group 2 trading program a quantity of allowances available for compliance under the 2023–2024 control periods many times the levels that the EPA determined to be appropriate emissions budgets for these states in the CSAPR Update. Through the use of banked allowances, the excess Group 2 allowances would affect compliance under the Group 2 trading program in control periods after 2024 as well. Continued implementation of the Group 2 trading program at levels of stringency consistent with the levels contemplated under the CSAPR Update therefore requires that the EPA limit the use of the excess allowances, as the EPA is doing through the recall provisions.

In this rule, the EPA is implementing limitations on the use of the excess 2023–2024 Group 2 allowances through requirements to surrender, for each 2023–2024 Group 2 allowance recorded in a newly added Group 3 source's compliance account, one Group 2 allowance of equivalent usability under the Group 2 trading program. The surrender requirements apply to the owners and operators of the Group 3 sources in whose compliance account the excess 2023–2024 Group 2 allowances were initially recorded. In general, each source's current owners and operators are required to comply with the surrender requirements for the source by ensuring that sufficient allowances to complete the deductions are available in the source's compliance account by one of two possible deadlines discussed later in this section. However, an exception is provided if a source's current owners and operators obtained ownership and operational control of the source in a transaction that did not include rights to direct the use and transfer of some or all of the 2023–2024 Group 2 allowances allocated and recorded (either before or after that transaction) in the source's compliance account. The rule provides that in such a circumstance, with respect to the 2023–2024 Group 2 allowances for which rights were not included in the transaction, the surrender requirements apply to the most recent former owners and operators of the source before any such transactions occurred. Because in this situation a source's former owners and operators might lack the ability to access the source's compliance account for purposes of complying with the surrender requirements, the former owners and operators would instead be allowed to meet the surrender requirements with Group 2 allowances held in a general account.[372]

To provide as much flexibility as possible consistent with the need to limit the use of the excess Group 2 allowances, for each 2023–2024 Group 2 allowance recorded in a Group 3 source's compliance account, the EPA will accept the surrender of either the same specific 2023–2024 Group 2 allowance or any other Group 2 allowance with equivalent (or greater) usability under the Group 2 trading program. Thus, a surrender requirement with regard to a Group 2 allowance allocated for the 2023 control period could be met through the surrender of any Group 2 allowance allocated for the 2023 control period or the control period in any earlier year—in other words, any 2017–2023 Group 2 allowance.[373] Similarly, the surrender requirement with regard to a 2024 Group 2 allowance could be met through the surrender of any 2017–2024 Group 2 allowance.

Owners and operators subject to the surrender requirements can choose from two possible deadlines for meeting the requirements. The optional first deadline will be 15 days after the effective date of this rule.[374] As soon as practicable or after this date, the EPA will make a first attempt to complete the deductions of Group 2 allowances required for each Group 3 source from the source's compliance account. The EPA will deduct Group 2 allowances first to address any surrender requirements for the 2023 control period and then to address any surrender requirements for the 2024 control period. When deducting Group 2 allowances to address the surrender requirements for each control period, EPA will first deduct allowances allocated for that control period and then will deduct allowances allocated for each successively earlier control period. This order of deductions is intended to ensure that whatever Group 2 allowances are available in the account are applied to the surrender requirements in a manner that both maximizes the extent to which all of the source's surrender requirements will be met and also ensures that any Group 2 allowances left in the source's compliance account after completion of all required deductions will be the earliest allocated, and therefore most useful, Group 2 allowances possible. Among the Group 2 allowances allocated for a given control period, The EPA will first deduct allowances that were initially recorded in that account, in the order of recordation, and will then deduct allowances that were transferred into that account after having been initially recorded in some other account, in the order of recordation.

Following the first attempt to deduct Group 2 allowances to address Group 3 sources' surrender requirements, the

[372] The EPA is currently unaware of any source that would need to use this flexibility but has included the option in the rule to address the theoretical possibility of such a situation.

[373] The first control period for the Group 2 trading program was in 2017.

[374] As discussed later in this section and in section VI.B.9.b, the EPA has conditioned recordation of any allocations of Group 3 allowances in a source's compliance account on the source's prior compliance with the recall requirements for Group 2 allowances. The purpose of providing an optional first deadline for the recall provisions 15 days after a final rule's effective is to ensure that sources have an early opportunity to comply with the recall provisions to be eligible to have allocations of Group 3 allowances recorded in their accounts 30 days after the final rule's effective date. Because the vast majority of sources subject to the recall provisions already hold sufficient Group 2 allowances to comply with the recall provisions, the EPA anticipates that the sources will easily be able to comply with the optional first recall deadline.

EPA will send a notification to the designated representative for each such source (as well as any alternate designated representative) indicating whether all required deductions were completed and, if not, the additional amounts of Group 2 allowances usable in the 2023 or 2024 control periods that must be held in the appropriate account by the second surrender deadline of September 15, 2023. Each notification will be sent to the email addresses most recently provided to the EPA for the recipients and will include information on how to contact the EPA with any questions. The EPA has provided that no allocations of Group 3 allowances will be recorded in a source's compliance account until all the source's surrender requirements with regard to 2023–2024 Group 2 allowances have been met. For this reason, the principal consequence to a source of failure to fully comply with the surrender requirements by 15 days after the effective date of this rule will be that any Group 3 allowances allocated to the units at the source for the 2023 and 2024 control periods that would otherwise have been recorded in the source's compliance account by 30 days after the effective date of a final rule will not be recorded as of that recordation date.

If all surrender requirements of 2023–2024 Group 2 allowances for a source have not been met in EPA's first attempt, the EPA will make a second attempt to complete the required deductions from the source's compliance account (or from a specified general account, in the limited circumstance noted previously) as soon as practicable on or after September 15, 2023. The order in which Group 2 allowances are deducted will be the same as described previously for the first attempt.

If the second attempt to deduct Group 2 allowances to meet the surrender requirements through deductions from the source's compliance account (or from a specified general account) is unsuccessful for a given source, as soon as practicable on or after November 15, 2023, to the extent necessary to address the unsatisfied surrender requirements for the source, the EPA will deduct the 2023–2024 Group 2 allowances that were initially recorded in the source's compliance account from whatever accounts the allowances are held in as of the date of the deduction, except for any allowances where, as of April 30, 2022, no person with an ownership interest in the allowances was an owner or operator of the source, was a direct or indirect parent or subsidiary of an owner or operator of the source, or was directly or indirectly under common ownership with an owner or operator of the source.[375] Before making any deduction under this provision, the EPA will send a notification to the authorized account representative for the account in which the allowance is held and will provide an opportunity for submission of objections concerning the data upon which the EPA is relying. In EPA's view, this provision does not unduly interfere with the legitimate expectations of participants in the allowance markets because the provision will not be invoked in the case of any allowance that was transferred to an independent party in an arms-length transaction before EPA's intent to recall 2023–2024 Group 2 allowances became widely known. The provision would apply only to a Group 2 allowance that, as of April 30, 2022, was still controlled either by the owners and operators of the source in whose compliance account it was initially recorded or by an entity affiliated with such an owner or operator. The EPA believes that by April 30, 2022, all market participants had ample opportunity to become informed of the proposed rule provisions to recall 2023–2024 Group 2 allowances recorded in Group 3 sources' compliance accounts, particularly since the EPA implemented a closely analogous recall of Group 2 allowances in the Revised CSAPR Update.[376]

The final revised regulations provide that failure of a source's owners and operators to comply with the surrender requirements will be subject to possible enforcement as a violation of the CAA, with each allowance and each day of the control period constituting a separate violation.

To eliminate any possible uncertainty regarding the amounts of Group 2 allowances allocated for the 2023–2024 control periods (or earlier control periods) that the owners and operators of each Group 3 source are required to surrender under the recall provisions, the EPA has prepared a list of the sources in the additional Group 3 states and areas of Indian country in whose compliance accounts allocations of 2023–2024 Group 2 allowances were recorded, with the amounts of the allocations recorded in each such compliance account for the 2023 and 2024 control periods. An additional list shows, for each newly added Group 3 source, the specific Group 2 allowances (batched by serial number) allocated for each control period and recorded in the source's compliance account and indicates whether, as of April 30, 2022, that batch of allowances was held in the source's compliance account, in an account believed to be partially or fully controlled by a related party (*i.e.,* an owner or operator of the source or an affiliate of an owner or operator of the source), or in an account believed to be fully controlled by independent parties. The lists are in a spreadsheet titled, ''Recall of Additional CSAPR NO_X Ozone Season Group 2 Allowances,'' available in the docket for this rule. After the first and second surrender deadlines, the EPA intends to update the lists to indicate for each Group 3 source whether the surrender requirements for the source under the recall provisions have been fully satisfied. The EPA will post the updated lists on a publicly accessible website to ensure that all market participants have the ability to determine which specific 2023–2024 Group 2 allowances initially recorded in any given Group 3 source's compliance account do or do not remain subject to potential deduction to address the source's surrender requirements under the recall provisions.

The recall provisions have been finalized without change from the proposal. The EPA received no comments on the proposed provisions.

13. Conforming Revisions to Regulations for Other CSAPR Trading Programs

As noted in section VI.B.1.a of this document, in addition to the Group 3 trading program, EPA currently administers five other CSAPR trading programs, all of which have provisions that in most respects parallel the provisions of the Group 3 trading program.[377] In this rulemaking, in addition to the revisions to the Group 3 trading program, the EPA is finalizing a set of conforming revisions that concern how various areas of Indian country are

[375] The provision under which the EPA will not deduct Group 2 allowances transferred to unrelated parties before April 30, 2022 from the transferees' accounts does not relieve the source to which the Group 2 allowances were originally allocated from the obligation to comply with the recall requirements. Specifically, the source would be required to comply with the recall requirements by obtaining and surrendering other Group 2 allowances.

[376] Even before publication of the proposed rule, the EPA posted information on its websites to notify market participants that a pending rulemaking could have consequences for the value and usability of Group 2 allowances. The posted locations included the electronic portal that authorized account representatives use to enter allowance transfers for recordation by the EPA in the Allowance Management System. Additionally, the EPA emailed a notice identifying the possibility of such consequences to the representatives for all Allowance Management System accounts.

[377] The regulations for the Group 3 Trading Program are at 40 CFR part 97, subpart GGGGG. The regulations for the other five CSAPR trading programs are at 40 CFR part 97, subparts AAAAA, BBBBB, CCCCC, DDDDD, and EEEEE.

treated for purposes of the allowance allocation provisions of the regulations for all the CSAPR trading programs.[378]

As discussed in section VI.B.9.a of this document, to reflect the D.C. Circuit's holding in *ODEQ* v. *EPA* that states have initial CAA implementation planning authority in non-reservation areas of Indian country until displaced by a demonstration of tribal jurisdiction over such an area, the EPA is revising the allowance allocation provisions in the Group 3 trading program regulations so that, instead of distinguishing between the sets of units within a given state's borders that either are not or are in Indian country, the revised regulations distinguish between (1) the set of units within the state's borders that are not in Indian country or are in areas of Indian country covered by the state's CAA implementation planning authority and (2) the set of units within the state's borders that are in areas of Indian country not covered by the state's CAA implementation planning authority. For the same reasons stated in section VI.B.9.a of this document for the Group 3 trading program, the EPA is revising the allowance allocation provisions in the regulations for all the other CSAPR trading programs establishing the same substantive distinction among the sets of units within each state's borders. The specific regulatory provisions that are affected are identified in section IX.D of this document. The EPA is unaware of any currently operating units that would be affected by this revision to the regulations for the other CSAPR trading programs.

The conforming revisions to the regulations for the other CSAPR trading programs concerning Indian country are being finalized as proposed with no changes. The EPA received no comments on this portion of the proposal.

C. Regulatory Requirements for Stationary Industrial Sources

The EPA is finalizing FIPs with requirements for certain non-EGU industry sources for 20 of the states covered in this final rule. See section II.B of this document for the list of states. The FIPs include new emissions limitations for units in nine non-EGU industries that the EPA finds (as discussed in sections IV and V of this final rule) are significantly contributing to nonattainment or interfering with maintenance in other states. The emissions control requirements of these FIPs for non-EGU sources apply only during the ozone season (May through September) each year, beginning in 2026.

To achieve the necessary non-EGU emissions reductions for these 20 states, the EPA is finalizing the proposed emissions limitations with some adjustments as a result of information received during the public comment period. The final emissions limits apply to the most impactful types of units in the relevant industries and are achievable with the control technologies identified in this preamble and further discussed in the Final Non-EGU Sectors TSD. The non-EGU regulatory requirements unique to each industry that EPA is finalizing after considering public comments are discussed in sections VI.C.1 through VI.C.6 of this document.

These final FIP requirements apply to both new and existing emissions units. The non-EGU emissions limits and compliance requirements will apply in all 20 states (and, as discussed in section III.C.2 of this document, in areas of Indian country within the borders of those states), even if some of those states do not currently have emissions units in a particular source category. This approach is consistent with the approach that the EPA proposed, and the EPA did not receive any comments specifically objecting to our proposal to regulate new units. This approach will ensure that all new sources constructed in any of the 20 states will be subject to the same good neighbor requirements that apply to existing units under this final rule. This will also avoid creating incentives to move production from an existing non-EGU source to a new non-EGU source of the same type but lacking the relevant emissions control requirements either within a linked state or in another linked state.

Comment: The EPA received several comments regarding the proposed approach of establishing unit-specific emissions limitations for non-EGUs instead of an emissions trading program. Some commenters suggested that a trading program for non-EGUs could provide for operational flexibility and that EPA should allow sources to work with regulatory authorities to develop a trading program. Other commenters generally supported EPA's proposed approach and the decision to not include non-EGUs in an emissions trading program, because the EPA would not need to require sources to unnecessarily install CEMS. Commenters from several states and industry groups generally supported other monitoring options over CEMS, such as parametric monitoring, performance testing, and predictive emissions monitoring systems (PEMS). Additional commenters voiced concern with the expense and burden of continuous parametric monitoring and semi-annual performance tests. Specifically, commenters explained that semi-annual testing should not be required when the emissions limits only apply during the ozone season. Commenters also noted that many non-EGU boilers have recently been relieved from meeting the CEMS requirements under the 1998 NO_X SIP Call and that implementing CEMS on many of the non-EGU sources would be difficult and unnecessary.

Response: The EPA is finalizing a unit-specific approach with rate-based emissions limitations set on a uniform basis for the different segments of non-EGU emissions units using applicability criteria based on size and type of unit and, in some cases, emissions thresholds. In response to public comments, the EPA has adjusted these requirements as necessary to ensure that the emissions control requirements are achievable while ensuring that the FIPs achieve the necessary emissions reductions from the covered units to eliminate significant contribution to nonattainment and interference with maintenance as discussed in section V of this document. The EPA has concluded that a unit-specific approach is more appropriate for non-EGUs at this time than implementing a trading program and requiring all units to implement rigorous part 75 monitoring and reporting requirements. As explained in the proposal, to be considered for a trading program, non-EGU sources would have to comply with requirements for monitoring and reporting of hourly mass emissions in accordance with 40 CFR part 75 as we have required for all previous trading programs. Monitoring and reporting under part 75 include CEMS (or an approved alternative method), rigorous initial certification testing, and periodic quality assurance testing thereafter, such as relative accuracy test audits and daily calibrations. Consistent and accurate measurement of emissions is necessary to ensure that each allowance actually represents one ton of emissions and that one ton of reported emissions from one source would be equivalent to one ton of reported emissions from another source. *See* 75 FR 45325 (August 2, 2010). Moreover, these monitoring requirements generally would need to be in place for at least

[378] Additional conforming revisions concerning the schedules for the EPA to record allowance allocations in source's compliance accounts and for states to submit state-determined allowance allocations to the EPA for subsequent recordation were finalized in an earlier final rule in this docket. See 87 FR 52473 (August 26, 2022).

one full ozone season to establish baseline data before it would be appropriate to rely on a trading program as the mechanism to achieve the required emissions reductions. Many industry and state commenters provided information confirming that many non-EGU units subject to this rulemaking do not currently utilize CEMS and specifically requested that EPA avoid requiring CEMS for all non-EGU industries. The EPA generally agrees that CEMS is not necessary for all non-EGU industries under the approach of this final rule and is finalizing other continuous monitoring, recordkeeping, and reporting requirements, as appropriate, that are specific to each non-EGU industry. The EPA has determined that establishing unit-specific emissions limitations for non-EGUs is a preferable approach in part because it avoids the rigorous monitoring requirements that would be applied to non-EGUs for the first time under a trading program.

Furthermore, to address commenters' concerns regarding non-EGU requirements for performance testing on a semi-annual basis, the EPA has also reduced the frequency of all required performance testing for non-EGU sources to once per calendar year. As commenters correctly pointed out, the emissions limits in these final FIPs only apply during the ozone season and testing once per calendar year should be sufficient to confirm the accuracy of the parameters being monitored to demonstrate continuous compliance during the ozone season. The EPA also agrees with commenters that the annual testing requirements need not occur during the ozone season.

In addition, the EPA is modifying the applicability criteria and other regulatory requirements in response to public comments to provide certain compliance flexibilities for non-EGU industries where appropriate. As discussed further in section V.C.1 of this document, the EPA is modifying the requirements for Pipeline Transportation of Natural Gas by finalizing an exemption for emergency engines and allowing any owner or operator of an affected unit to propose a ''Facility-Wide Averaging Plan'' that would, if approved by EPA, provide an alternative means for compliance with the emissions limits in this final rule. Further, as discussed in section VI.C.5 of this document, the EPA is finalizing a low-use exemption for non-EGU boilers that operates less than 10 percent per year on an hourly basis, based on the three most recent years of use and no more than 20 percent in any one of the three years. These final rule provisions require controls on the most impactful non-EGU industrial sources while providing the flexibility needed to accommodate unique circumstances on a case-by-case basis.

Comment: Commenters from several non-EGU industries and states raised general concerns regarding the ability for all sources to comply with the proposed emissions limits. Some commenters suggested that the EPA allow for case-by-case limits where necessary, similar to case-by-case RACT determinations. Specifically, commenters operating boilers, furnaces, and MWCs provided general explanations of how some units might not be able to meet the proposed emissions limits and requested that EPA provide for compliance flexibility where a source can demonstrate technical and economical infeasibility.

Response: As explained more in sections VI.C.1 through VI.C.6, the EPA has made several adjustments to the proposed applicability criteria, emissions limits, and compliance requirements in response to public comments and to reduce the costs of compliance with the final rule. For Pipeline Transportation and Natural Gas, the EPA is finalizing emissions averaging provisions and exemptions for emergency engines to allow facilities to avoid installing controls on units with lower actual emissions where the installation of controls would be less cost effective compared to higher-emitting units. For Cement and Concrete Product Manufacturing, the EPA has removed the daily source cap that would have resulted in an artificially restrictive NO_X emissions limit for affected cement kilns that have operated at lower levels due to the COVID–19 pandemic. For Iron and Steel and Ferroalloy Manufacturing, the EPA is finalizing a ''test-and-set'' requirement for reheat furnaces that will require the installation of low-NO_X burners or equivalent technology. The EPA has addressed the economic concerns raised by commenters regarding installation of controls at Iron and Steel facilities by not finalizing the other ten proposed emissions limits that were intended to require the installation of SCR at these facilities. For Glass and Glass Product Manufacturing, the EPA is finalizing alternative standards that apply during startup, shutdown, and idling conditions. For boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, Pulp, Paper, and Paperboard Mills, Metal Ore Mining, and the Iron and Steel Industry, the EPA is finalizing a low-use exemption to eliminate the need to install controls on boilers that would have resulted in relatively small reductions in emissions. Finally, the EPA has modified the monitoring and recordkeeping requirements for all non-EGU industries where possible to reduce the testing frequency to once a year and to provide for alternative monitoring protocols where appropriate, which should further reduce the costs of compliance on non-EGU sources. With these modifications to the final rule in response to comments, the non-EGU sources subject to this rule should be able to meet the applicable control requirements established in this final rule.

The EPA also recognizes, however, that there may be unique circumstances the Agency cannot anticipate that would, for a particular source, render the final emissions control requirements technically impossible or impossible without extreme economic hardship. To address these limited circumstances, the EPA is finalizing a provision that allows a source to request EPA approval of a case-by-case emissions limit based on a showing that an emissions unit cannot meet the applicable standard due to technical impossibility or extreme economic hardship. The EPA has modeled the case-by-case emissions limit mechanism on case-by-case RACT requirements and certain facility-specific emissions limits under 40 CFR part 60 identified by commenters.[379] The owner or operator of a source seeking a case-by-case emissions limit must submit a request meeting specific requirements to the EPA by August 5, 2024, one year after the effective date of this final rule. The applicable emissions limits established in this final rule remain in effect until the EPA approves a source's request for a case-by-case emissions limit. Given the May 1, 2026 compliance date that generally applies to all affected units in the non-EGU industries covered by this final rule, we encourage owners and operators of affected units who believe they must seek case-by-case emissions limits to submit their requests to the EPA before the one-year deadline for such requests, if possible, to ensure adequate time for EPA review and to install the necessary controls.

For a source requesting a case-by-case limit due to technical impossibility, the final rule requires that the request include emissions data obtained through CEMS or stack tests, an analysis

[379] For examples of case-by-case RACT provisions and source specific limits for boilers in subpart Db of the EPA's NSPS, see 40 CFR 60.44b(f); Regulations of Connecticut State Agencies section 22a–174–22e; Code of Maryland Regulations section 26.11.09.08(B)(3); and Code of Maine Rules section 096–138–3, subsection (I).

of all available control technologies based on an engineering assessment by a professional engineer or data from a representative sample of similar sources, and a recommendation concerning the most stringent emissions limit the source can technically achieve.

For a source requesting a case-by-case limit on the basis of extreme economic hardship, the final rule requires that the request include at least three vendor estimates from three separate vendors that do not have a corporate or business-affiliation with the source of the costs of installing the control technology necessary to meet the applicable emissions limit and other information that demonstrates, to the satisfaction of the Administrator, that the cost of compliance with the applicable emissions limit for that particular source would present an extreme economic hardship relative to the costs borne by other comparable sources in the industry under this rule. In evaluating a source's request for a case-by-case limit due to extreme economic hardship, the EPA will consider the emissions reductions and costs identified in this final rulemaking (and related support documents) for other sources in the relevant industry and whether the costs of compliance for the source seeking the case-by-case limit would significantly exceed the highest representative end of the range of estimated cost-per-ton figures identified for any source in the relevant industry as discussed in section V of this document.

As discussed in section VI.A of this document, in *Wisconsin* the court held that some deviation from the CAA's mandate to eliminate prohibited transport by downwind attainment deadlines may be allowed only ''under particular circumstances and upon a sufficient showing of necessity,'' *e.g.,* when compliance with the statutory mandate amounts to an impossibility.[380] Given these directives, the EPA cannot allow a covered source to avoid complying with the emissions limits established in this final rule unless the source can demonstrate that compliance with the limit would either be impossible as a technical matter or result in an extreme economic hardship—*i.e.,* exceed the high end of the cost-effectiveness estimates that informed the EPA's Step 3 determination of significant contribution, as discussed in section V of this document. The criteria that must be met to qualify for a case-by-case limit are designed to meet this statutory mandate.

Comment: Several commenters raised concerns about the EPA's differing applicability criteria for the various non-EGU industries. Specifically, the commenters questioned why EPA set applicability criteria for engines in Pipeline Transportation of Natural Gas and non-EGU boilers based on design capacity instead of potential to emit (PTE). Commenters also requested that the EPA allow each non-EGU category to rely on operating permits or other federally enforceable instruments to avoid being subject to the rule, such as limits to the PTE or limits on fuels used.

Response: The 100 tpy PTE threshold and comparable design capacity thresholds of 1,000 horsepower (hp) for engines and 100 mmBtu/hr for boilers are appropriate to ensure that the final rule reduces emissions from the most impactful units. The EPA finds the control technologies assumed to be installed to meet the final emissions limits would not be as readily available or cost effective for emissions units with PTE or design capacities lower than the applicability thresholds in this final rule.

With regard to the selection of design capacity thresholds for boilers and engines, the EPA finds that most RACT requirements and other standards reviewed by the EPA establish applicability criteria for engines and boilers based on design capacity rather than PTE. We further explain our basis for establishing applicability thresholds based on design capacity for these two source categories in sections VI.C.1. and VI.C.5. For consistency with preexisting requirements for engines and boilers and to capture the sizes of units identified in Step 3 of our analysis, the EPA selected design capacities of 1,000 hp for engines and 100 mmBtu/hr for boilers. The EPA recognizes that these applicability thresholds captured more units than the EPA intended, particularly some low-use units. Therefore, as explained in sections VI.C.1 and VI.C.5., the EPA is establishing exemptions for low-use boilers and emergency engines, as well as new emissions averaging provisions for engines, to ensure that this final rule focuses on larger, more impactful units.

The EPA also agrees with commenters that the applicability criteria should allow for sources to rely on enforceable requirements that limit a source's PTE and is finalizing a regulatory definition of PTE that is generally consistent with the definitions of that term in the EPA's title V and NSR permit programs. *See, e.g.,* 40 CFR 51.165(a)(1)(iii), 70.2. In constructing the list of potential sources subject to the final rule, the EPA relied on available information to identify the PTE of the emissions units in the various non-EGU industries that are captured by the applicability criteria. *See Memo to Docket titled Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs.* Thus, the EPA's Step 3 analysis takes into account available information about currently enforceable emissions limits and physical and operational limitations identified in existing permits. The EPA finds it necessary to define PTE consistent with its use in the title V and NSR permit programs to ensure that the requirements of the final FIPs apply to the most impactful units identified in Step 3 of our analysis. However, to ensure that these FIPs achieve the emissions reductions necessary to eliminate significant contribution or interference with maintenance as described in this final rule, the applicability criteria for the Cement and Concrete Manufacturing, Iron and Steel and Ferroalloy Manufacturing, and Glass and Glass Product Manufacturing industries take into account only those enforceable PTE limits in effect as of the effective date of this final rule. Thus, any emissions unit in these three industries that has a PTE equal to or greater than 100 tons per year and thus meets the definition of an ''affected unit'' as of August 4, 2023, will remain subject to the applicable FIPs, without regard to any PTE limit that the emissions unit may subsequently become subject to. Each affected unit in these three industries must submit an initial notification of applicability to the EPA by December 4, 2023, that identifies its PTE as of the effective date of this final rule. Additionally, any owner or operator of an existing emissions unit that is not an affected unit as of August 4, 2023, but subsequently meets the applicability criteria (*e.g.,* due to a change in fuel use that increases the unit's PTE) will become an affected unit subject to the applicable requirements of this final rule at that time.

Comment: In responding to the EPA's request for comment on whether some non-EGU units would need to run controls required by the final FIP year-round, one commenter anticipated that control equipment would be operated as necessary to achieve applicable emissions limits, but that operational

[380] *Wisconsin,* 938 F.3d at 316 and 319–320 (noting that any such deviation must be ''rooted in Title I's framework'' and ''provide a sufficient level of protection to downwind States'').

flexibility, cost considerations and equipment longevity would warrant operation of certain control equipment on a schedule such that the equipment would not be used when unnecessary to meet emissions limits and/or outside of ozone season (*i.e.,* during winter months). The commenter further explained that flexibility in the operation of certain control equipment when unnecessary to meet emissions limits will allow for routine maintenance and repairs without requiring variances or similar exemptions from continuous operation requirements.

Response: Based on the feedback received during the public comment period, the EPA is finalizing requirements for non-EGU sources that will apply only during the ozone season, which runs annually from May to September. As discussed in the proposed rule, this is consistent with EPA's prior practice in Federal actions to eliminate significant contribution of ozone in the 1998 NO_X SIP Call, CAIR, CSAPR, CSAPR Update, and the Revised CSAPR Update. In addition, the EPA did not receive any information during the public comment period suggesting that sources would have to run the necessary controls year-round due to the nature of those controls. We note, however, that certain emissions-control technologies, such as combustion controls that are integrated into the unit itself, would likely function to reduce NO_X emissions year-round as a practical engineering matter.

Comment: Regarding electronic reporting through the Compliance and Emissions Data Reporting Interface (CEDRI), one commenter requested that CEDRI reporting requirements be consolidated in one location rather than repeated in each section. Another commenter requested that EPA include electronic reporting requirements for MWCs and specifically require that MWCs report CEMS data to CEDRI. Another commenter requested that EPA allow for extensions of time for electronic reports due to technical glitches.

Response: To increase the ease and efficiency of data submittal and data accessibility, the EPA is finalizing, as proposed, a requirement that owners and operators of non-EGU sources subject to the final FIPs, including MWCs, submit electronic copies of required initial notifications of applicability, performance test reports, performance evaluation reports, quarterly and semi-annual reports, and excess emissions reports through EPA's Central Data Exchange (CDX) using the CEDRI. The final rule requires that performance test results collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the ERT website [381] at the time of the test be submitted in the format generated through the use of the ERT or an electronic file consistent with the XML schema on the ERT website and that other performance test results be submitted in portable document format (PDF) using the attachment module of the ERT. Similarly, the EPA is finalizing a requirement that performance evaluation results of CEMS measuring relative accuracy test audit (RATA) pollutants that are supported by the ERT at the time of the test be submitted in the format generated through the use of the ERT or an electronic file consistent with the XML schema on the ERT website, and a requirement that other performance evaluation results be submitted in PDF using the attachment module of the ERT. The final rule also requires that initial notifications of applicability, annual compliance reports, and excess emissions reports be submitted in PDF uploaded in CEDRI.

Furthermore, the EPA is finalizing, as proposed, provisions that allow owners and operators to seek extensions of time to submit electronic reports due to circumstances beyond the control of the owner or operator (*e.g.,* due to a possible outage in CDX or CEDRI or a *force majeure* event) in the time just prior to a report's due date, as well as provisions specifying how to submit such a claim. Public commenters supported these proposed provisions.

The EPA agrees with commenters that the CEDRI reporting requirements could be centralized and has moved the CEDRI reporting requirements to 40 CFR 52.40.

1. Pipeline Transportation of Natural Gas

Applicability

The EPA is finalizing regulatory requirements for the Pipeline Transportation of Natural Gas industry that apply to stationary, natural gas-fired, spark ignited reciprocating internal combustion engines (''stationary SI engines'') within these facilities that have a maximum rated capacity of 1,000 hp or greater. Based on our review of the potential emissions from stationary SI engines, we find that use of a maximum rated capacity of 1,000 hp reasonably approximates the 100 tpy PTE threshold used in the *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026,* as described in section V.B of this document.

The EPA is also modifying certain provisions in response to public comments to provide compliance flexibilities for the Pipeline Transportation of Natural Gas industry sector in order to focus emissions reduction efforts on the highest emitting units. Specifically, the EPA is finalizing an exemption for emergency engines, and establishing provisions that allow any owner or operator of an affected unit to propose a Facility-Wide Averaging Plan that would, if approved by EPA, provide an alternative means for compliance with the emissions limits in this final rule.

For purposes of this rule, the EPA is clarifying and narrowing the definition of ''pipeline transportation of natural gas'' to mean the transport or storage of natural gas prior to delivery to a local distribution company custody transfer station or to a final end-user (if there is no local distribution company custody transfer station). The revised definition of this term in § 52.41(a) is consistent with the EPA's regulatory definition of ''natural gas transmission and storage segment'' in 40 CFR 60.5430(a) (subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After September 18, 2015).

The EPA is also adding definitions of the terms ''local distribution company'' and ''local distribution company custody transfer station'' that are consistent with the definitions found in 40 CFR 98.400 (subpart NN, Suppliers of Natural Gas and Natural Gas Liquids) and 40 CFR 60.5430(a) (subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After September 18, 2015), respectively.

Comment: Several commenters asked EPA to exclude emergency engines in the final rule and one commenter recommended that the EPA revise the definition of affected unit to specifically exempt emergency engines. Commenters stated that doing so would not only be consistent with other regulations applicable to stationary SI engines, but it would also be more consistent with EPA's applicability analysis, which assumes stationary SI engines will operate for 7,000 hours a year, something emergency engines are prohibited from doing by Federal regulation. Commenters also stated that emergency generators are currently exempt from requirements applicable to non-emergency RICE covered by both

[381] The ERT website is located at *https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert.*

the relevant NSPS rule (subpart JJJJ), as well as the relevant NESHAP rule (subpart ZZZZ), and that although the NSPS and NESHAP standards EPA has adopted for emergency RICE do not limit the amount of time they may run for emergency purposes, EPA has recognized in the past that states may assume a maximum of 500 hours of operation to estimate the ''potential to emit'' in issuing air permits for emergency RICE. One commenter asserted that emergency engines operating under other standards currently only operate for emergencies or for a few hours at a time to periodically conduct regular maintenance, that their emissions are low, and that their contribution to the ozone transport issues EPA's proposal seeks to address is negligible. Another commenter stated that the EPA has traditionally exempted emergency engines in past standards because the EPA has typically found that the use of add-on emissions controls cannot be justified due to the cost of the technology relative to the emissions reduction that would be obtained.

Response: With respect to stationary SI emergency engines, the EPA has reviewed the information submitted by the commenters and has decided to exempt such engines from the requirements of the final rule. Exemption of emergency engines is generally consistent with the EPA's treatment of emergency engines in other CAA rulemakings. *See, e.g.,* 40 CFR 63.6585(f). The EPA expects that this change from the proposed rule addresses the concerns expressed by the commenters about the requirements for stationary emergency engines.

The final rule defines emergency engines as engines that are stationary and operated to provide electrical power or mechanical work during an emergency situation. These engines are typically used only a few hours per year, and the costs of emissions control are not warranted when compared to the emissions reductions that would be achieved.

In the final rule, emergency engines are subject to certain compliance requirements on a continuous basis. Continuous compliance requirements include operating limitations that apply during non-emergency use but do not include emissions testing of emergency engines.

Comment: Several commenters raised concerns about the EPA's proposal to establish applicability criteria for engines in Pipeline Transportation of Natural Gas based on design capacity rather than PTE. Other commenters asserted that the horsepower rating of an engine does not necessarily correspond to its annual emissions and that engines with a rated capacity of more than 1,000 hp in this industry sector may operate at low load and/or infrequently and be associated with limited NO_X emissions. One commenter stated that most of the subject facilities in their state that have natural gas fired SI engines with a nameplate capacity rating of 1,000 hp or greater have annual NO_X emissions less than 100 tpy, with nearly 25 percent of them less than 25 tpy. The commenter suggested that the 1,000 hp applicability threshold would result in overcontrol. According to one commenter, the EPA has overestimated the emissions rates and operating hours of engines with a rated capacity of more than 1,000 hp and thus underestimated the size of pipeline RICE that would be expected to emit more than 100 tpy of NO_X annually. According to this commenter, only engines much larger than 1,000 hp are likely to emit at the level EPA deemed appropriate for regulation.

Another commenter suggested that the EPA should use a 150 ton per year threshold that the commenter alleges was used in the Revised CSAPR Update rulemaking so that stationary SI engines are regulated on equal footing with EGUs and raise the 1,000 hp threshold to 2,000 hp, which according to the commenter would not sacrifice the emissions reductions to be achieved.

Response: As explained in the proposal, the EPA found that most RACT requirements and other standards reviewed by the EPA establish applicability criteria for engines based on design capacity rather than PTE. For consistency with preexisting requirements for engines, the EPA selected a design capacity of 1,000 hp for engines to capture the sizes of units identified in Step 3 of our analysis. Based on the Non-EGU Screening Assessment memorandum, engines with a potential to emit of 100 tpy or greater had the most significant potential for NO_X emissions reductions. The EPA recognizes that the use of a 1,000 hp design capacity as part of the applicability criteria may capture low-use units and some units with emissions of less than 100 tons per year. However, it is also not possible to guarantee without an effective emissions control program that all such units could not increase emissions in the future. As discussed in section V of this document, we continue to find that collectively engines with a design capacity of 1,000 hp or higher in the states and industries covered by this final rule emit substantial amounts of NO_X that significantly contribute to downwind air quality problems.

However, in response to concerns raised by commenters while continuing to ensure that this rule establishes an effective emissions control program for these units that is consistent with our Step 3 determinations, the EPA is establishing a compliance alternative using facility-wide emissions averaging, which will allow facilities to prioritize emissions reductions from larger, higher-emitting units. (As previously discussed, we are also establishing an exemption for emergency engines, which also helps ensure that this final rule focuses on larger, more impactful units in this industry.) The facility-wide emissions averaging alternative is explained in the following paragraphs.

Emissions Limitations and Rationale

In developing the emissions limits for the Pipeline Transportation of Natural Gas industry, the EPA reviewed RACT NO_X rules, air permits, and OTC model rules. While some permits and rules express engine emissions limits in parts per million by volume (ppmv), the majority of rules and source-specific requirements express the emissions limits in grams per horsepower per hour (g/hp-hr). The EPA has historically set emissions limits for these types of engines using g/hp-hr and finds that method appropriate for this final FIP as well.

Based on the available information for this industry, including applicable State and local air agency rules and active air permits issued to sources with similar engines, the EPA is finalizing the following emissions limits for stationary SI engines in the covered states. Beginning in the 2026 ozone season and in each ozone season thereafter, the following emissions limits apply, based on a 30-day rolling average emissions rate during the ozone season:

TABLE VI.C–1—SUMMARY OF FINAL NO_X EMISSIONS LIMITS FOR PIPELINE TRANSPORTATION OF NATURAL GAS

Engine type and fuel	Final NO_X emissions limit (g/hp-hr)
Natural Gas Fired Four Stroke Rich Burn	1.0
Natural Gas Fired Four Stroke Lean Burn	1.5
Natural Gas Fired Two Stroke Lean Burn	3.0

The EPA anticipates that, in some cases, affected engines will need to install NO_X controls to comply with the final emissions limits in Table VI.C–1. The emissions limits for four stroke rich burn engines, four stroke lean burn engines and two stroke lean burn engines are designed to be achievable by installing Non-Selective Catalytic Reduction (NSCR) on existing four stroke rich burn engines; installing SCR on existing four stroke lean burn engines; and retrofitting layer combustion on existing two stroke lean burn engines as identified in the Final Non-EGU Sectors TSD. Sources have the flexibility to install any other control technologies that enable the affected units to meet the applicable emissions limit on a continuous basis.

The EPA is establishing provisions that allow any owner or operator of an affected unit in the Pipeline Transportation of Natural Gas Industry to propose a Facility-Wide Averaging Plan that would, if approved by EPA, provide an alternative means for compliance with the emissions limits in this final rule. These provisions will provide some flexibility to owners and operators of affected units to determine which engines to control and at what level, so long as the average emissions across all covered units, on a weighted basis, meet the applicable emissions limits for each engine type. This approach allows facilities to target the most cost-effective emissions reductions and to avoid installing controls on equipment that is infrequently operated.

We provide a more detailed discussion of the basis for the final emissions limits and the anticipated control technologies to be installed in the Final Non-EGU Sectors TSD.

Four Stroke Rich Burn and Four Stroke Lean Burn Engines

The EPA requested comment on whether a lower emissions limit is appropriate for four stroke rich burn engines since even an assumed reduction of 95 percent would result in most engines being able to achieve an emissions rate of 0.5 g/hp-hr. The EPA also requested comment on whether a lower or higher emissions limit is appropriate for four stroke lean burn engines.

Comment: One commenter stated that the limits as proposed were not technically feasible in all circumstances. The commenter explained that its company has 150 four stroke rich burn engines in its fleet and that some of those engines cannot achieve the proposed 1.0 g/hp-hr limit even with both NSCR and layered combustion due to the vintage design of the individual cylinder geometry and the fact that most of these engines are not in production today, which limits availability of parts and retrofit technologies. The commenter asserted that 10 of its four stroke rich burn engines have all available controls on them and half of those still exceed the proposed limits. The commenter estimated that 10 of its four stroke lean burn engines would require SCR to meet the 1.5 g/hp-hr limit and that this control installation would require custom retrofit due to the age of these engines. Furthermore, the commenter stated that if current limits are not achievable in all circumstances, then lower limits are likewise impossible for four stroke rich burn engines and four stroke lean burn engines in even more circumstances. The commenter stated that the technical feasibility of installing controls on any single existing engine varies and depends, in part, on site-specific and engine-specific considerations such as space for the installation of the control, the availability of sufficient power, the emissions reductions required to meet the applicable standards, and the vintage, make, and model of a particular engine. Another commenter recommended tightening the proposed emissions standards for four stroke lean burn engines to an emissions limit similar to Colorado's limit of 1.2 g/hp-hr. A third commenter noted that the District of Columbia Department of Energy and Environment has NO_X emissions limits for both rich- and lean burn engines burning natural gas at 0.7 g/hp-hr.

Response: The EPA is finalizing the emissions limits for both four stroke rich burn engines and four stroke lean burn engines as proposed but also establishing alternative compliance provisions and criteria for establishing case-by-case alternative emissions limits in response to the concerns raised by commenters. NSCR can achieve NO_X reductions of 90 to 99 percent, and engines in California, Colorado, Pennsylvania and Texas have achieved the emissions limits that the EPA had proposed. Based on this information and the emissions limits and NO_X controls analysis developed by the OTC in a report entitled *Technical Information Oil and Gas Sector Significant Stationary Sources of NO_X Emissions* (October 17, 2012), the EPA is finalizing a 1.0 g/hp-hr emissions limit for four stroke rich burn engines and a 1.5 g/hp-hr emissions limit for four stroke lean burn engines. The Final Non-EGU Sectors TSD provides a more detailed explanation of the basis for these emissions limits.

To address the concerns raised by some commenters that not all engines may be able to achieve the emissions limits as proposed due to engine vintage and technical constraints, the final rule allows any owner or operator of an affected unit to request a Facility-Wide Averaging Plan that would, if approved by EPA, provide an alternative means for compliance with the emissions limits in the final rule. An approved Facility-Wide Averaging Plan would allow the owner or operator of the facility to identify the most cost-effective means for installing the necessary controls (*i.e.,* by installing controls on the subset of engines that provide the greatest emissions reduction potential at lowest costs). In addition to the Facility-Wide Averaging Plan provisions, the final rule allows owners and operators to seek EPA approval of alternative emissions limits, on a case-by-case basis, where necessary due to technical impossibility or to avoid extreme economic hardship. The provisions governing case-by-case alternative limits are explained in more detail in section VI.C of this document.

Two Stroke Lean Burn Engines

The EPA requested comment on whether a lower emissions limit would be achievable with layered combustion alone for the two stroke lean burn engines covered by this final rule. The

EPA also sought comment on whether these engines could install additional control technology at or below the marginal cost threshold to achieve a lower emissions rate.

Comment: Commenters did not specifically address whether a lower emissions limit would be achievable with layered combustion alone at two stroke lean burn engines. However, one commenter stated that older two stroke lean burn engines generally would not be able to achieve the proposed NO_X emissions limits. The commenter stated that conversion kits are available for several models that can reduce emissions but that such kits are not made for all models, especially older stationary engines. Commenters further stated that where conversion kits are not available, a company would likely have no choice but to replace the older four stroke or two stroke stationary engines, typically at a cost of $2 million to $4 million each.

Two commenters stated that they are required by their state agency to have RACT, BACT, or BART controls, at minimum. Commenters stated that requiring additional controls at facilities already equipped with RACT, BACT or BART control technologies would not achieve the anticipated emissions reductions due to operational factors inherent in the preexisting and pre-controlled equipment and that the achievability of targeted control levels is highly dependent upon a number of variables at each facility.

Another commenter suggested that the EPA set lower limits for two stroke lean burn engines similar to the OTC-recommended limits in the range of 1.5–2.0 g/hp-hr.

Response: Information currently available to the EPA indicates that the amount of emissions reductions achievable with layered combustion controls is unit specific and can range from a 60 to 90 percent reduction in NO_X emissions. The EPA estimates that existing uncontrolled two stroke lean burn engines would need to reduce emissions by up to 80 percent to comply with a 3.0 g/hp-hr emissions limit. The EPA has found that engines in California, Colorado, Pennsylvania and Texas have achieved these emissions rates. Based on this information and the emissions limits and NO_X controls analysis developed by the OTC in a report entitled *Technical Information Oil and Gas Sector Significant Stationary Sources of NO_X Emissions* (October 17, 2012), the EPA is finalizing a 3.0 g/hp-hr emissions limit for two stroke lean burn engines. Although some affected units may be able to achieve a lower emissions rate, we find that a 3.0 g/hp-hr emissions limit generally reflects a level of control that is cost-effective for the majority of the affected units and sufficient to achieve the necessary emissions reductions. As explained in the proposed rule and expressed by public commenters, if the EPA were to establish an emissions limit lower than 3.0 g/hp-hr, some two stroke lean burn engines would not be able to meet the emissions limit with the installation of layered combustion control alone. In that case, the lower limit might require the installation of SCR, which the EPA did not find to be cost-effective for two stroke lean burn engines in its Step 3 analysis.[382] The Final Non-EGU Sectors TSD provides a more detailed explanation of the basis for this emissions limit.

In response to commenters' concerns about the difficulties involved in retrofitting or replacing older stationary engines to achieve the EPA's proposed emissions limit, the final rule allows any owner or operator of an affected unit to request a Facility-Wide Averaging Plan that would, if approved by EPA, provide an alternative means for compliance with the emissions limits in the final rule. In addition to the Facility-Wide Averaging Plan provisions, the final rule allows owners and operators to seek EPA approval of alternative emissions limits, on a case-by-case basis, where necessary due to technical impossibility or to avoid extreme economic hardship. However, in the context of older or ''vintage,'' high-emitting engines in this industry for which commenters claim emissions control technology retrofit is not feasible, the Agency anticipates taking into consideration the cost associated with alternative compliance strategies, such as replacement with new, far more efficient and less polluting engines, in evaluating claims of extreme economic hardship.

Facility-Wide Averaging Plan

The EPA is finalizing regulatory text that provides for an emissions limit compliance alternative using facility-level emissions averaging. An approved Facility-Wide Averaging Plan will allow the owner or operator of the facility to average emissions across all participating units and thus to select the most cost-effective means for installing the necessary controls (*i.e.,* by installing controls on the subset of engines that provide the greatest emissions reduction potential at lowest costs and avoiding installation of controls on equipment that is infrequently operated or otherwise less cost-effective to control). So long as all of the emissions units covered by the Facility-Wide Averaging Plan collectively emit less than or equal to the total amount of NO_X emissions (in tons per day) that would be emitted if each covered unit individually met the applicable NO_X emissions limitations, the covered units will be in compliance with the final rule. Under this alternative compliance option, facilities have the flexibility to prioritize emissions reductions from larger, dirtier engines.

Comment: Several commenters recommended that the EPA promulgate emissions averaging provisions, as it did in the 2004 NO_X SIP Call Phase 2 rule (69 FR 21604), in which the EPA evaluated and supported reliance on emissions averaging for RICE in the Pipeline Transportation of Natural Gas industry sector. The commenter stated that the EPA's guidance to states on developing an appropriate SIP in response to the SIP Call provided companies the ''flexibility'' to use a number of control options, as long as the collective result achieved the required NO_X reductions, and that many states built their revised SIPs around the emissions averaging approach addressed in this guidance document.[383] One commenter recommended that the EPA allow intra-state emissions averaging across all pipeline RICE owned or operated by the same company. Another commenter asserted that units of certain vintages and units from certain manufacturers will not be able to meet the emissions rate limits the EPA had proposed. The commenter claimed that, absent a system based on source-specific emissions limits, emissions averaging is one of the only practical mechanisms for addressing these challenges.

One commenter stated that it had evaluated the cost of controls for engines in its fleet and that the variety in cost-per-ton for each potential project counsels for a more flexible approach, like an averaging program. Another commenter advocated for an emissions averaging plan that would allow an engine-by-engine showing of economic infeasibility to ensure a cost-effective application of the emissions standards, a reduced impact on natural gas capacity, and a means for addressing the problem presented by achieving

[382] 87 FR 20036, 20143 (noting that an emissions limit below 3.0 g/hp-hr may require some two stroke lean burn engines to install additional controls beyond the EPA's cost threshold).

[383] The commenter refers to an August 22, 2002 memorandum from Lydia N. Wegman, Director, EPA, Air Quality Strategies and Standards Division to EPA Air Division Directors, entitled ''State Implementation Plan (SIP) Call for Reducing Nitrogen Oxides (NO_X)—Stationary Reciprocating Internal Combustion Engines.''

compliance on engines that are technically impossible to retrofit.

One commenter stated that the EPA should also consider allowing companies to choose a mass-based alternative that would ensure emissions reductions align with the tons per year reductions upon which the EPA based its significant contribution and over-control analyses.

Response: Based upon the EPA's 2019 NEI emissions inventory data, the EPA estimates that a total of 3,005 stationary SI engines are subject to the final rule. The EPA recognizes that many low-use engines are captured by the 1,000 hp design capacity applicability threshold. In the process of reviewing public comments, the EPA reviewed emissions averaging plans found in state air quality rules for Colorado, Illinois, Louisiana, New Jersey, and Tennessee.[384] Based on these additional reviews, the EPA is finalizing in § 52.41(c) of this final rule an emissions limit compliance alternative using facility-level emissions averaging. Emissions averaging plans will allow facility owners and operators to determine how to best achieve the necessary emissions reductions by installing controls on the affected engines with the greatest emissions reduction potential rather than on units with lower actual emissions where the installation of controls would be less cost effective. The final rule defines ''facility'' consistent with the definition of this term as it generally applies in the EPA's NSR and title V permitting regulations,[385] with one addition to make clear that, for purposes of this final rule, a ''facility'' may not extend beyond the boundaries of the 20 states covered by the FIP for industrial sources, as identified in § 52.40(b)(2). Because a facility cannot extend beyond this geographic area, a Facility-Wide Averaging Plan also cannot extend beyond the 20-state area covered by the FIP.

To estimate the number of facilities that may take advantage of the Facility-Wide Averaging Plan provisions, and the number of affected units that would install controls under such an emissions averaging plan, the EPA conducted an analysis on a subset of the estimated 3,005 stationary IC engines subject to the final rule. The EPA evaluated the reported actual NO_X emissions data in tpy from a subset of facilities in the covered states using 2019 NEI data for stationary IC engines with design capacities of 1,000 hp or greater. The EPA then identified a number of facilities that have more than one affected engine, calculated each facility's emissions ''cap'' as the total NO_X emissions (in tpy) allowed facility-wide based on the unit-specific NO_X emissions limits applicable to all affected units at the facility, and identified a number of higher-emitting engines at each facility that were candidates for having controls installed. For engines that EPA identified were likely to install controls, the EPA assumed that four stroke rich burn engines, four stroke lean burn engines, and two stroke lean burn engines could achieve a NO_X emissions rate of 0.5 g/hp-hr with the installation of SCR based on data obtained from the Ozone Transport Commission report entitled *Technical Information Oil and Gas Sector Significant Stationary Sources of NO_X Emissions* (October 17, 2012). For the remaining engines identified as uncontrolled, the EPA assumed a NO_X emissions rate of 16 g/hp-hr for all engine types. Thus, under the assumed averaging scenarios, engines with controls installed would achieve emissions levels below the emissions limits in the final rule and would offset the higher emissions from the remaining uncontrolled units.

The EPA then calculated the total facility-wide emissions (in tpy) under various assumed averaging scenarios and compared those totals to each facility's calculated emissions cap (in tpy) to estimate the number of affected units at each facility that would need to install controls to ensure that total facility-wide emissions remained below the emissions cap. Based on these analyses, the EPA found that emissions averaging should allow most facilities to install controls on approximately one-third of the engines at their sites, on average, while complying with the applicable NO_X emissions cap on a facility-wide basis. For a more detailed discussion of the EPA's analysis and related assumptions, see the Final Non-EGU Sectors TSD.

The Facility-Wide Averaging Plan provisions that the EPA is finalizing provide the flexibility needed to address the concerns about the costs of emissions control installations for certain stationary SI engines, by allowing facility owners and operators to average emissions across all participating units and thus to select the most cost-effective means for installing the necessary controls (*i.e.,* by installing controls on the subset of engines that provide the greatest emissions reduction potential at lowest costs and avoiding installation of controls on equipment that is infrequently operated or otherwise less cost-effective to control).

An owner or operator of a facility containing more than one affected unit may elect to use an EPA-approved Facility-Wide Averaging Plan as an alternative means of compliance with the NO_X emissions limits in § 52.41(c). The owner or operator of such a facility must submit a request to the EPA that, among other things, specifies the affected units that will be covered by the plan, provides facility and unit-level identification information, identifies the facility-wide emissions ''cap'' (in tpd) that the facility must comply with on a 30-day rolling average basis, and provides the calculation methodology used to demonstrate compliance with the identified emissions cap. The EPA will approve a request for a Facility-Wide Averaging Plan if the EPA determines that the facility-wide emissions total (in tpd), based on a 30-day rolling emissions average basis during the ozone season, is less than the emissions cap (in tpd) and the plan establishes satisfactory means for determining initial and continuous compliance, including appropriate testing, monitoring, and recordkeeping requirements.

Compliance Assurance Requirements

The EPA is requiring owners and operators of affected units to conduct annual performance tests in accordance with 40 CFR 60.8 to demonstrate compliance with the NO_X emissions limit in this final rule. The EPA is also requiring owners and operators to monitor and record hours of operation and fuel consumption and to use continuous parametric monitoring systems to demonstrate ongoing compliance with the applicable NO_X emissions limit. For example, owners and operators of engines that utilize layered combustion controls will need to monitor and record temperature, air to fuel ratio, and other parameters as appropriate to ensure that combustion conditions are optimized to reduce NO_X emissions and assure compliance with the emissions limit. For engines using SCR or NSCR, owners and operators must monitor and record parameters such as inlet temperature to the catalyst

[384] *See* Code of Colorado Regulations, Regulation Number 7 (5 CCR 1001–9), Part E, Section I.D.5.c., Illinois Administrative Code, Title 35, Section 217.390, Louisiana Administrative Code, Title 33, Section 2201, New Jersey Administrative Code, Title 7, Chapter 27, Section 19.6, and Rules of the Tennessee Dept. of Environment and Conservation, Rule 1200–03–27–.09.

[385] See 40 CFR 51.165(a)(1)(ii)(A), 51.166(b)(6)(i), and 52.21(b)(6)(i) (defining ''building, structure, facility, or installation'' for Nonattainment New Source Review and Prevention of Significant Deterioration permits) and *Natural Resources Defense Council* v. *EPA,* 725 F.2d 761 (D.C. Cir. 1984) (vacating and remanding EPA's categorial exclusion of vessel activities from this definition); see also 40 CFR 70.2 (defining ''major source'' for title V operating permits).

and pressure drop across the catalyst. For affected engines that meet the certification requirements of § 60.4243(a), however, the facility-wide emissions calculations may be based on certified engine emissions standards data pursuant to § 60.4243(a), instead of performance tests.

In calculating the facility-wide emissions total during the ozone season, affected engines covered by the Facility-Wide Averaging Plan must be identified by each engine's nameplate capacity in horsepower, its actual operating hours during the ozone season, and its emissions rates in g/hp-hr from certified engine data or from the most recent performance test results for non-certified engines according to § 52.41(e).

Comment: Several commenters stated that semi-annual performance testing would not be appropriate due to its high costs and limited benefits. One commenter proposed a ''step-down'' testing alternative that could be conducted after establishing an engine's initial compliance via performance testing. Under this approach, owners and operators would conduct one performance test and would only need to conduct a second performance test within a given year if the first performance test demonstrated that an engine was not meeting the applicable emissions standards.

Another commenter asserted that to test all of its 950 units, a minimum of 12 months would be needed rather than the six months the EPA had proposed to provide (or five months if the EPA would require one of the semi-annual tests to be conducted during the ozone season). The commenter stated that the EPA had accounted for these operational realities in the past and that under the NSPS and NESHAP, testing is generally required only once for every 8,760 hours of run time. The commenter asserted that there is no reason to require more frequent testing than those required under the NSPS and NESHAP.

Several commenters requested that the EPA allow for reduction in the frequency of testing to once every two years if testing shows that NO_X emissions are no more than 75 percent of permitted NO_X emissions limits. In addition, several commenters stated that since the rule is intended to address the ozone season, a single, annual test is more feasible than semi-annual testing and reporting.

Response: For the stationary SI engines subject to this final rule, the EPA is revising the frequency of required performance tests from a semi-annual basis to once per calendar year. As commenters correctly pointed out, the emissions limits in these final FIPs only apply during the 5-month ozone season and testing once per calendar year should be sufficient to confirm the accuracy of the parameters being monitored to determine continuous compliance during the ozone season. The EPA also agrees with commenters that the annual tests required under the final rule need not occur during the ozone season. However, where sources are able to do so, we recommend conducting a stack test in the period relatively soon before the start of the ozone season. This would provide the greatest assurance that the emissions control systems are working as intended and the applicable emissions limit will be met when the ozone season starts.

Comment: Commenters generally stated that requiring CEMS would add an unnecessary cost and complexity, would provide no emissions reduction benefit for the affected units the proposed FIP intends to control and are not warranted due to the availability of other established methods of compliance assurance, such as parametric monitoring and periodic testing. One commenter stated that requiring CEMS would add unnecessary CEMS testing obligations. Another commenter stated that the costs associated with CEMS and frequent performance testing on affected RICE would be as much, if not more, than the costs associated with installation and operation of some of the control technologies EPA has considered in setting the proposed emissions limits. According to one commenter, the EPA has traditionally agreed with this viewpoint on the high cost of CEMS, as most stationary engines are not currently required under the NSPS or NESHAP to install or operate CEMS.

Another commenter stated that in addition to cost, there are other barriers to installing CEMS on RICE across the Pipeline Transportation of Natural Gas industry. Many RICE in the Pipeline Transportation of Natural Gas industry are located at remote, unstaffed locations, meaning that there would be no staff available to respond and react to communication or alarms from CEMS.

Response: The EPA acknowledges the costs associated with the installation and maintenance of CEMS at affected units in the Pipeline Transportation of Natural Gas industry and agrees that it is not necessary to require CEMS for purposes of compliance with the requirements of this final rule for this industry. Accordingly, the EPA is not finalizing requirements for affected units in this industry sector to install or operate CEMS. Instead, the EPA is requiring parametric monitoring protocols, as described earlier, coupled with an annual performance test, which will ensure that the emissions limits are legally and practically enforceable on a continuous basis, and that data are recorded, reported, and can be made publicly available, ensuring the ability of state and Federal regulators and other persons under CAA sections 113 and 304 to enforce the requirements of the Act.

2. Cement and Concrete Product Manufacturing

Applicability

For cement kilns in the Cement and Cement Product Manufacturing industry, the EPA is finalizing the proposed applicability provisions without change. The affected units in this industry are cement kilns that emit or have a PTE of 100 tpy or more of NO_X. The EPA received comments regarding the definition of PTE, which we address in section VI.C, but no comments concerning the 100 tpy PTE threshold for applicability purposes.

Emissions Limitations and Rationale

As explained in the proposal, the EPA based the proposed emissions limits for cement kilns on the types of limits being met across the nation in RACT NO_X rules, NSPS, air permits, and consent decrees. Based on these requirements, the EPA proposed emissions limits in the form of mass of pollutant emitted (in pounds) per kiln's clinker output (in tons), *i.e.,* pounds of NO_X emitted per ton of clinker produced during a 30-operating day rolling average period. Further, the EPA proposed specific emissions limits for long wet, long dry, preheater, precalciner, and combined preheater/precalciner kilns. The EPA also proposed a daily source cap limit that would apply to all units at a facility. Based on information received from public comments, the EPA is removing the daily source cap limit but finalizing the emissions limits as proposed in all other respects, as shown in Table VI.C–2.

TABLE VI.C–2—SUMMARY OF NO_X EMISSIONS LIMITS FOR KILN TYPES IN CEMENT AND CONCRETE PRODUCT MANUFACTURING

Kiln type	NO_X emissions limit (lb/ton of clinker)
Long Wet	4.0
Long Dry	3.0
Preheater	3.8
Precalciner	2.3
Preheater/Precalciner	2.8

Comment: Numerous commenters raised concerns about designing a source cap limit based on average annual production in tons of clinker and kiln type. Commenters stated that the source cap limit equation as used in a prior action applied to long wet and dry preheater-precalciner or precalciner kilns and did not include other kiln types. Commenters expressed concern that the CAP2015 Ozone Transport equation the EPA proposed in this rule could lead to artificially low and restrictive daily emissions caps for facilities that experienced a temporary decrease in production due to the COVID–19 pandemic, during the historical three-year period proposed for use in determining the NO_X source cap. Also, commenters expressed concern that the proposed daily emissions cap limit originated as a local or regional limit for a single county and would not be appropriate for national application without further evaluation taking into account the specific characteristics of cement kilns in other states. One commenter suggested more stringent emissions limits than those the EPA had proposed for individual kiln types.

Response: The EPA is not finalizing the proposed daily source cap limit as the Agency agrees with the commenters that this proposed limit would be unnecessarily restrictive and was based on a formula that did not include all kiln types. Given the unusual reduction in cement production activities due to the COVID–19 pandemic, production rates during the 2019–2021 period are not representative of cement plants activities generally. Accordingly, use of the proposed daily source cap limit would result in an artificially restrictive NO_X emissions limit for affected cement kilns, particularly when this sector operates longer hours during the spring and summer construction season. With respect to those comments supporting more stringent emissions limits than those the EPA proposed for individual kiln types, we disagree given the significant differences among different kilns in design, configuration, age, fuel capabilities, and raw material composition. The EPA finds that the ozone season emissions limits for individual kiln types listed in Table VI.C–2 will achieve the necessary emissions reductions for purposes of eliminating significant contribution as defined in section V and is, therefore, finalizing these emissions limitations without change.

Comment: One commenter supported retirement of existing long wet kilns and replacement of these kilns with modern kilns. Other commenters opposed the phase out and retiring of these kilns, stating that many of the screened kilns have SNCR already installed and questioning whether replacement of existing long wet kilns is cost-effective. Some commenters also stated that according to EPA's ''NO_X Control Technologies for the Cement Industry, Final Report,'' SNCR is not an appropriate NO_X control technique for long wet kilns.

Response: The EPA appreciates the challenges identified by commenters, such as site-specific technical evaluation and review and significant capital investment associated with undertaking kiln conversions or to install new kilns and is not finalizing any requirements to replace existing long wet kilns in this rule.

Comment: Several commenters expressed concern about the supply chain issues relevant to the procurement, design, construction, and installation of control devices, as well as securing related contracts, for the cement industry, particularly when cement sources will be competing with the EGU and other industrial sectors for similar services. One commenter stated that many preheater/precalciner kilns are already equipped with SNCR and that one facility not equipped with SNCR is already meeting NO_X emissions levels of 1.95 lb/ton of clinker or less. The commenter stated that the EPA should revise its assessment of potential NO_X reductions and cost estimates by accurately accounting for existing operating efficiencies and control devices at cement kilns.

Response: The EPA's response to comments on the time needed for installation of controls for non-EGU sources is provided in section VI.A. Regarding the comment that certain facilities may already have SNCR control technology installed, we recognize that many sources throughout the EGU sector and non-EGU industries covered by this rule may already be achieving enforceable emissions performance commensurate with the requirements of this action. This is entirely consistent with the logic of our 4-step interstate transport framework, which is designed to bring all covered sources within the region of linked upwind states up to a uniform level of NO_X emissions performance during the ozone season. *See EME Homer City,* 572 U.S. at 519. Sources that are already achieving that level of performance will face relatively limited compliance costs associated with this rule.

Compliance Assurance Requirements

The EPA received no comments on the proposed test methods and procedures provisions for the cement industry. Therefore, we are finalizing the proposed test methods and procedures for affected cement kilns without change.

Comment: Commenters generally supported requiring performance testing or installation of CEMS on affected cement kilns. Some commenters suggested that no performance testing should be required and others suggested that performance testing should only be required when a title V permit is due for renewal (every 5 years). One commenter suggested requiring sources to conduct stack tests during the ozone season.

Response: Affected kilns that operate a NO_X CEMS may use CEMS data consistent with the requirements of 40 CFR 60.13 in lieu of performance tests to demonstrate compliance with the requirements of this final rule. For affected kilns subject to this final rule that do not employ NO_X CEMS, the EPA is adjusting the performance testing frequency and requiring kilns to conduct a performance test on an annual basis during a given calendar year.[386] The EPA finds that annual performance testing and recordkeeping of cement production and fuel consumption during the ozone season will assure compliance with the emissions limits during the ozone season (May through September) each year for purposes of this rule. The required annual performance test may be performed at any time during the calendar year. However, where sources are able to do so, we recommend conducting a stack test in the period relatively soon before the start of the ozone season. This would provide the greatest assurance that the emissions control systems are working as intended and the applicable emissions limit will be met when the ozone season starts.

Comment: One commenter stated that CEMS has been used successfully at its facility. Another commenter explained that the inside of a cement kiln is an extremely challenging environment for making any kind of continuous measurement as temperatures are high, and there is a lot of dust and tumbling clinker can damage in situ measuring instruments.

Response: The majority of cement kilns in the United States are already equipped with CEMS. However, in response to commenters concerns regarding the installation of CEMS, the EPA is finalizing alternative compliance requirements in lieu of CEMS. Owners or operators of affected emissions units without CEMS installed must conduct annual performance testing and continuous parametric monitoring to demonstrate compliance with the emissions limits in this final rule. Specifically, owners or operators of affected units without CEMS must monitor and record stack exhaust gas flow rate, hourly production rate, and stack exhaust temperature during the initial performance test and subsequent annual performance tests to assure compliance with the applicable emissions limit. The owner or operator must then continuously monitor and record those parameters to demonstrate continuous compliance with the NO_X emissions limits.

3. Iron and Steel Mills and Ferroalloy Manufacturing

Applicability

The EPA is establishing emissions control requirements for the Iron and Steel Mills and Ferroalloy Manufacturing source category that apply to reheat furnaces that directly emit or have the potential to emit 100 tpy or more of NO_X. After review of all available information received during public comment, the EPA has determined that there is sufficient information to determine that low-NO_X burners can be installed on reheat furnaces. As explained further in the Final Non-EGU Sectors TSD, the EPA identified 32 reheat furnaces with low-NO_X burners installed and has concluded that low-NO_X burners are a readily available and widely implemented emissions reduction strategy.[387] This rule defines reheat furnaces to include all furnaces used to heat steel product—metal ingots, billets, slabs, beams, blooms and other similar products—to temperatures at which it will be suitable for deformation and further processing.

Comment: Several industry commenters requested that the EPA not include certain iron and steel emissions units—including blast furnaces, basic oxygen furnaces (BOFs), ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, and electric arc furnaces (EAFs)—in the final rule as proposed due to, among other things, the uniqueness of each emissions unit, various design-related challenges, and expected impossibility of successful implementation of add-on NO_X control technology. Commenters expressed concern about requirements to install SCR for all iron and steel units for which the EPA proposed emissions limits. The commenters stated that iron and steel units had not installed SCR except in a few rare instances for experimental reasons and that SCR technology was not readily available or known for the iron and steel industry, unlike the control technologies expected to be installed in other non-EGU industries. Furthermore, commenters stated that SCR had not been applied for RACT, BACT, or LAER purposes on iron and steel units.

Response: In light of the comments we received on the complex economic and, in some cases, technical challenges associated with implementation of NO_X control technologies on certain emissions units in this sector, the EPA is not finalizing the proposed emissions limits for blast furnaces, BOFs, ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, or EAFs.

The EPA is aware of many examples of low-NO_X technology utilized at furnaces, kilns, and other emissions units in other sectors with similar stoichiometry, including taconite kilns, blast furnace stoves, electric arc furnaces (oxy-fuel burners), and many other examples at refineries and other large industrial facilities. The EPA anticipates that with adequate time, modeling, and optimization efforts, such NO_X reduction technology may be achievable and cost-effective for these emissions units in the Iron and Steel Mills and Ferroalloy Manufacturing sector as well. However, the data we have reviewed is insufficient at this time to support a generalized conclusion that the application of NO_X controls, including SCR or other NO_X control technologies such as LNB, is currently both technically feasible and cost effective on a fleetwide basis for these emission source types in this industry. We provide a more detailed discussion of the economic and technical issues associated with implementation of NO_X control technologies on these emissions units, including information provided by commenters, in section 4 of the Final Non-EGU Sectors TSD.

Reheat furnaces are the only type of emissions unit within the Iron and Steel Mills and Ferroalloy Manufacturing industry that this final rule applies to. Low-NO_X controls (*e.g.,* low-NO_X burners) are a demonstrated control technology that many reheat furnaces have successfully employed.

Comment: One commenter claimed that the proposed definition of ''reheat furnaces'' is overly vague and requested that the EPA amend the definition. Specifically, the commenter asserted that the EPA's proposed definition does not indicate what counts as ''steel product'' and whether this includes only products that have already been manufactured into some form before being introduced to a reheat furnace, or whether it also includes steel that has never left the original production process, such as hot steel coming directly from a connected casting process which has not yet been formed into a definitive product. The commenter referenced the definition of reheat furnaces in Ohio's RACT regulations as an example to consider.

Response: In response to these comments, the EPA is finalizing a definition of reheat furnaces that is consistent with the definition in Ohio's NO_X RACT regulations. *See* Ohio Admin. Code 3745–110–01(b)(35) (March 25, 2022). Specifically, the EPA is defining reheat furnaces to mean ''all furnaces used to heat steel product, including metal ingots, billets, slabs, beams, blooms and other similar products, to temperatures at which it will be suitable for deformation and further processing.''

[386] 40 CFR 63.11237 ''Calendar year'' defined as the period between January 1 and December 31, inclusive, for a given year.

[387] See Final Non-EGU Sectors TSD, Section 4.

Emissions Control Requirements, Testing, and Rationale

Based on the available information for this industry, applicable Federal and state rules, and active air permits or enforceable orders issued to affected facilities in the iron and steel and ferroalloy manufacturing industry, the EPA is finalizing requirements for each facility with an affected reheat furnace to design, fabricate and install high-efficiency low-NO_X burners designed to reduce NO_X emissions from pre-installation emissions rates by at least 40 percent by volume, and to conduct performance testing before and after burner installation to set emissions limits and verify emissions reductions from pre-installation emissions rates. Each low-NO_X burner shall be designed to achieve at least 40 percent NO_X reduction from existing reheat furnace exhaust emissions rates. Each facility with an affected reheat furnace shall, within 60 days of conclusion of the post-installation performance test, submit testing results to the EPA to establish NO_X emissions limits over a 30-day rolling average. Each proposed emissions limit must be supported by performance test data and analysis.

In evaluating potential emissions limits for the Iron and Steel and Ferroalloy Manufacturing industry, the EPA reviewed RACT NO_X rules, NESHAP rules, air permits and related emissions tests, technical support documents, and consent decrees. These rules and source-specific requirements most commonly express emissions limits for this industry in terms of mass of pollutant emitted (pounds) per operating hour (hour) (*i.e.,* pounds of NO_X emitted per production hour), pounds per energy unit (*i.e.,* million British thermal unit (mmBtu)), or pounds of NO_X per ton of steel produced. Regulated iron and steel facilities, including facilities operating reheat furnaces in this sector, routinely monitor and keep track of production in terms of tons of steel produced per hour (heat rate) as it pertains to each facility's rate of iron and steel production. Several facilities, including Steel Dynamics, Columbia, Indiana, Cleveland-Cliffs, Cleveland, Ohio, and Cleveland-Cliffs, Burns Harbor, Indiana, are already operating various types of reheat furnaces with low-NO_X burners and achieving emissions rates as low as 0.11 lb/mmBtu of NO_X. The EPA identified at least nine reheat furnaces with a PTE greater than 100 tpy, including slab, rotary hearth, and walking beam furnaces, that have installed low-NO_X burners and are achieving various emissions rates.[388]

Due to variations in the emissions rates that different types of reheat furnaces can achieve, the EPA is not finalizing one emissions limit for all reheat furnaces and is instead requiring the installation of low-NO_X burners or equivalent low-NO_X technology designed to achieve a minimum 40 percent reduction from baseline NO_X emission levels, together with source specific emissions limits to be set thereafter based on performance testing. Specifically, the final rule requires that each owner or operator of an affected unit submit to the EPA, within one year after the effective date of the final rule, a work plan that identifies the low-NO_X burner or alternative low-NO_X technology selected, the phased construction timeframe by which the owner or operator will design, install, and consistently operate the control device, an emissions limit reflecting the required 40 percent reduction in NO_X emission levels, and, where applicable, performance test results obtained no more than five years before the effective date of the final rule to be used as baseline emissions testing data providing the basis for the required emissions reductions. If no such data exist, then the owner or operator must perform pre-installation testing to establish baseline emissions data.

Comment: One commenter stated that the standard practice for setting NO_X limits for iron and steel sources often requires consideration of site or unit-specific issues. Similarly, another commenter stated that a single limit would not provide an adequate basis for establishing NO_X emissions limits that will universally apply to multiple, unique facilities. The same commenter stated that NO_X reduction in certain furnaces is routinely achievable by combustion controls or measures other than SCR.

Response: The EPA acknowledges the difficulty in crafting one emissions limit for multiple iron and steel facilities and units of varying size, age, and design, in light of the unique issues associated with varying unit types in this particular industry. We also acknowledge that in some cases, reheat furnaces are equipped with recently installed, high-efficiency low-NO_X burners. Many sources throughout the EGU sector and non-EGU industries covered by this rule may already be achieving enforceable emissions performance commensurate with the requirements of this action. This is entirely consistent with the logic of our 4-step interstate transport framework, which is designed to bring all covered sources within the region of linked upwind states up to a uniform level of NO_X emissions performance during the ozone season. *See EME Homer City,* 572 U.S. at 519. Sources that are already achieving that level of performance will face relatively limited compliance costs associated with this rule.

The EPA is finalizing requirements for reheat furnaces to install high-efficiency low-NO_X burners designed to reduce NO_X emissions from pre-installation emissions rates by 40 percent by volume, and to perform pre- and post-installation performance testing at exhaust outlets to determine rate-based emissions limits for reheat furnaces in lb/hour, lb/mmBtu, or lb/ton on a rolling 30-operating day average. Owners and operators of affected units must also monitor NO_X emissions from reheat furnaces using CEMS or annual performance testing and recordkeeping and operate low-NO_X burners in accordance with work practice standards set forth in the regulatory text. Due to the many types of emissions units within the Iron and Steel Mills and Ferroalloy Manufacturing industry, and the limited information available at this time regarding NO_X control options that are achievable for these units, the EPA is finalizing requirements only for reheat furnaces at this time.

Comment: Commenters expressed concern that the proposed emissions limits identified both a 3-hour and a 30-day averaging time for the same limits and requested that the EPA clarify the averaging time in the final rule. Commenters requested that the EPA finalize limits with a 30-day averaging time consistent with the requirements for other non-EGU industries.

Response: In determining the appropriateness of 30-day rolling averaging times, the EPA initially reviewed the NESHAP for Iron and Steel Foundries codified at 40 CFR part 63, subpart EEEEE, the NESHAP for Integrated Iron and Steel manufacturing facilities codified at 40 CFR part 63, subpart FFFFF, the NESHAP for Ferroalloys Production: Ferromanganese and Silicomanganese codified at 40 CFR part 63, subpart XXX, and the NESHAP for Ferroalloys Production Facilities codified at 40 CFR part 63, subpart YYYYYY. The EPA also reviewed

[388] Specifically, through a review of title V permits, the EPA identified reheat furnaces with low-NO_X burners installed at Steel Dynamics in Columbia City, Indiana (two furnaces), Steel Dynamics in Butler, Indiana (one furnace), Cleveland Cliffs in Burns Harbor, Indiana (four furnaces), Cleveland Cliffs in East Chicago, Indiana (one furnace), and Cleveland Cliffs in Cleveland, Ohio (one furnace). For a further discussion of the limits and information on these facilities, see the Final Non-EGU Sectors TSD.

various RACT NO_X rules from states located within the OTR, several of which have chosen to implement OTC model rules and recommendations. Based on this information and the information provided by public commenters, the EPA is requiring a 30-operating day rolling average period as the averaging timeframe for reheat furnaces. The EPA finds that a 30-operating day rolling average period provides a reasonable balance between short term (hourly or daily) and long term (annual) averaging periods, while providing the flexibility needed to address fluctuations in operations and production.

Compliance Assurance Requirements

The EPA is finalizing requirements for each owner or operator of an affected unit in the Iron and Steel Mills and Ferroalloy Manufacturing industry to use CEMS or annual performance tests and continuous parametric monitoring to determine compliance with the 30-day rolling average emissions limit during the ozone season. Facilities choosing to use CEMS must perform an initial RATA per CEMS and maintain and operate the CEMS according to the applicable performance specifications in 40 CFR part 60, appendix B. Facilities choosing to use testing and continuous parametric monitoring for compliance purposes must use the test methods and procedures in 40 CFR part 60, appendix A–4, Method 7E, or other EPA-approved (federally enforceable) test methods and procedures.

Comment: Several commenters raised concerns with the requirement to install and operate CEMS to monitor NO_X emissions. Commenters cited the high relative costs of installing CEMS, especially for smaller units with lower actual emissions, and the complexities with installing CEMS on mobile reheat furnaces. Further, commenters explained that due to the unique configuration of certain facilities, it would be impossible for a CEMS to differentiate emissions from a reheat furnace and other units, like waste heat boilers. As an alternative to CEMS, commenters requested that the EPA finalize similar monitoring and recordkeeping requirements as proposed for the Cement and Concrete Product Manufacturing industry in the proposed rule, which allow for CEMS or performance testing and recordkeeping. Commenters explained that for reheat furnaces that are natural gas-fired, emissions can be tracked by relying on vendor guarantees and emissions factors and natural gas throughput.

Response: The EPA reviewed comments received from the industry regarding their concerns of affected units within the iron and steel mills and ferroalloy manufacturing sector being required to demonstrate compliance through CEMS. The EPA acknowledges the cost associated with the installation and maintenance of CEMS to demonstrate compliance with the finalized emissions standards for reheat furnaces. In this final rule, the EPA is revising the compliance assurance requirements to provide flexibility to owners or operators of affected units. Compliance may be demonstrated through CEMS or annual performance testing and continuous parametric monitoring to demonstrate compliance with the emissions limits in this final rule. If an affected unit does not use CEMS, the final rule requires the owner or operator to monitor and record stack exhaust gas flow rate, hourly production rate, and stack exhaust temperature during the initial performance test and subsequent annual performance tests to assure compliance with the applicable emissions limit. The owner or operator must then continuously monitor and record those parameters to demonstrate continuous compliance with the NO_X emissions limits. Affected units that operate NO_X CEMS meeting specified requirements may use CEMS data in lieu of performance testing and monitoring of operating parameters. For sources relying on annual performance tests and continuous parametric monitoring to assure compliance, the EPA is requiring that sources keep records of production and fuel usage during the ozone season to assure compliance with the emissions limits on a 30-day rolling average basis. To avoid challenges in scheduling and availability of testing firms, the annual performance test required under this final rule does not have to be performed during the ozone season. However, where sources are able to do so, we recommend conducting a stack test in the period relatively soon before the start of the ozone season. This would provide the greatest assurance that the emissions control systems are working as intended and the applicable emissions limit will be met when the ozone season starts.

4. Glass and Glass Product Manufacturing

Applicability

The EPA is finalizing regulatory requirements for the Glass and Glass Product Manufacturing source category that apply to furnaces that directly emit or have a PTE of 100 tpy or more of NO_X. For this industry, the EPA is finalizing the proposed applicability provisions without change.

Comment: One commenter requested that the applicability threshold for glass manufacturing furnaces should be based on a unit's design production capacity instead of the proposed applicability criteria (*i.e.,* units that directly emit or have the potential to emit 100 TPY or more of NO_X). The commenter stated that the production capacity for glass manufacturing furnaces is a more relevant basis for applicability and would focus the EPA analysis on cost-effective regulations.

Response: During the EPA's development of the proposed emissions limits, the EPA reviewed the applicability provisions in various state RACT NO_X rules, air permits, consent decrees, and Federal regulations applicable to glass manufacturing furnaces. Most of these applicability provisions were expressed in terms of actual emissions or PTE. Given the significant differences in the types, designs, configurations, ages, and fuel capabilities among glass furnaces, and differences in raw material compositions within the sector, the EPA finds that applicability criteria based on emissions or potential to emit are the most appropriate way to capture higher-emitting glass manufacturing furnaces that contribute NO_X emissions to downwind receptors.

Emissions Limitations and Rationale

The EPA is finalizing the proposed NO_X emissions limits for furnaces within the Glass and Glass Product Manufacturing industry, except that for flat glass manufacturing furnaces the EPA is finalizing an emissions limit slightly lower than the limit we had proposed, based on a correction to a factual error in our proposal. For further discussion of the basis for the form and level of the final emissions limits, see the proposed rule, 87 FR 20036, 20146 (April 6, 2022) (discussing EPA review of state RACT rules, NSPS, and other regulations applicable to the Glass and Glass Product Manufacturing industry). Several comments supported the EPA's effort to regulate sources within the Glass and Glass Product Manufacturing industry but also requested that the EPA establish more stringent emissions limits for this industry.

Comment: One commenter stated that NO_X emissions from the Glass and Glass Product Manufacturing industry are not currently subject to any Federal NSPS and that the industry is expected to grow in the coming years. The commenter stated that while the EPA's proposed limits on glass furnaces fell within the ranges of limits required by various states and air districts, they fell at the weakest levels within those ranges. For example, the commenter stated that the EPA had proposed a 4.0 lb/ton NO_X emissions limit for container glass manufacturing furnaces, while state and local NO_X emissions limits for these emissions units range from 1 to 4 lb/ton. Similarly, the commenter stated that the EPA had proposed a 4.0 lb/ton NO_X emissions limit for pressed/blown glass manufacturing furnaces, while state and local NO_X emissions limits for these emissions units range from 1.36 to 4 lb/ton, and that EPA had proposed a 9.2 lb/ton NO_X emissions limit for flat glass manufacturing furnaces, while state NO_X emissions limits for these emissions units range from 5–9.2 lb/ton. The commenter urged the EPA to establish emissions limits lower than those the EPA had proposed.

Response: The EPA is finalizing the emissions limits for affected units in the glass and glass product manufacturing industry as proposed for all but flat glass manufacturing furnaces, for which the EPA is finalizing a slightly lower emissions limit to reflect a correction to a factual error in our proposal. During the EPA's development of the proposed emissions limits, the EPA reviewed the control requirements or recommendations and related analyses in various RACT NO_X rules, air permits, Alternative Control Techniques (ACT) documents, and consent decrees to determine the appropriate NO_X emissions limits for the different types of glass manufacturing furnaces. Based on these reviews and given the significant differences in the types, designs, configurations, ages, and fuel capabilities among glass furnaces, and differences in raw material compositions within the sector, the EPA has concluded that it is appropriate to finalize the emissions limits for this industry as proposed, except for the limit proposed for flat glass manufacturing furnaces. For flat glass manufacturing furnaces, the EPA had proposed a NO_X emissions limit of 9.2 pounds (lbs) per ton of glass pulled but is finalizing a limit of 7.0 lbs/ton of glass pulled on a 30-day rolling average basis. This is based on our review of specific state RACT NO_X regulations that contain a 9.2 lbs/ton limit averaged over a single day but contain a 7.0 lbs/ton limit over a 30-day averaging period. This change aligns the final limit for flat glass manufacturing furnaces with the correct averaging time and is consistent with both the state RACT regulations that we reviewed [389] and our evaluation of cost-effective controls for this industry in the supporting documents for the proposed and final rule.

The EPA acknowledges that NO_X emissions from some glass manufacturing furnaces are subject to control under other regulatory programs, such as those adopted by states to meet CAA RACT requirements, and that some of these programs have implemented more stringent emissions limits than those the EPA is finalizing in these FIPs. However, as noted in the preamble to the proposed rule and related TSD, many OTR states do not establish specific NO_X emissions limits for glass manufacturing sources.[390] *See* 87 FR 20146. In addition to state RACT rules, air permits, ACT documents, and consent decrees applicable to this industry, the EPA reviewed reports and recommendations from the National Association of Clean Air Agencies (NACAA), the European Union Commission, and EPA's Menu of Control Measures (MCM) to identify potentially available control measures for reducing NO_X emissions from the glass manufacturing industry. The EPA also reviewed permit data for existing glass manufacturing furnaces to identify control devices currently in use at these sources. Based on these reviews, we find that the final emissions limits for the Glass and Glass Product Manufacturing industry provided in Table VI.C.3–1 generally reflect a level of control that is cost-effective for the majority of the affected units and sufficient to achieve the necessary emissions reductions. The Final Non-EGU Sectors TSD provides a more detailed explanation of the basis for these emissions limits.

TABLE VI.C.3–1—SUMMARY OF FINALIZED NO_X EMISSIONS LIMITS FOR FURNACE UNIT TYPES IN GLASS AND GLASS PRODUCT MANUFACTURING

Furnace type	NO_X emissions limit (lbs/ton of glass produced, 30 operating-day rolling average)
Container Glass Manufacturing Furnace	4.0
Pressed/Blown Glass Manufacturing Furnace or Fiberglass Manufacturing Furnace	4.0
Flat Glass Manufacturing Furnace	7.0

Alternative Emissions Standards During Periods of Start-Up, Shutdown, and Idling

Comment: Numerous commenters urged the EPA to provide additional flexibilities, alternative NO_X emissions limits, or exceptions to the NO_X emissions limits for glass manufacturing furnaces during periods of startup, shutdown and idling. Commenters requested that the EPA consider excluding days with low glass pull (*e.g.,* abnormally low production rate), furnace start-up days, furnace maintenance days, and malfunction days from the definition of ''operating day'' to allow for exclusion of these days from the calculation of an emissions unit's 30-operating day rolling average emissions. The commenters argued that because the glass furnace temperature is much lower during these periods than they are during normal operating conditions, it would be technologically infeasible to equip furnaces with NO_X control devices including SCR. Commenters also stated that because control equipment cannot be operated during these periods without damaging the equipment, it would be very difficult or impossible to meet the proposed NO_X limits during these periods.

Response: After review of the comments received and the EPA's assessment of current practices within

[389] For example, Pennsylvania's RACT NO_X emission limits for flat glass furnaces are 7.0 lbs of NO_X per ton of glass produced on 30-day rolling average. *See* Title 25, Part I, Subpart C, Article III, Section 129.304, available at *https://casetext.com/regulation/pennsylvania-code-rules-and-regulations/title-25-environmental-protection/part-i-department-of-environmental-protection/subpart-c-protection-of-natural-resources/article-iii-air-resources/chapter-129-standards-for-sources/control-of-nox-emissions-from-glass-melting-furnaces/section-129304-emission-requirements.*

[390] See Proposed Non-EGU Sectors TSD at 56, EPA–HQ–OAR–2021–0668–0145.

the glass manufacturing industry, the EPA is establishing provisions for alternative work practice standards and emissions limits that may apply in lieu of the emissions limits in § 52.44(c) during periods of start-up, shutdown, and idling. The emissions limits for glass melting furnaces in § 52.44(c) do not apply during periods of start-up, shutdown, and/or idling at affected units that comply instead with the alternative requirements for start-up, shutdown, and/or idling periods specified in § 52.44(d), (e), and/or (f), respectively. The EPA has modeled these alternative requirements that apply during startup, shutdown, and idling to some extent on State RACT requirements identified by commenters.[391] These alternative work practice standards adequately address the seven criteria that the EPA has recommended states consider when establishing appropriate alternative emissions limitations for periods of startup and shutdown.[392] We provide a more detailed evaluation of these provisions in the TSD supporting this final rule.

Specifically, each owner or operator of an affected unit seeking to comply with alternative work practice standards in lieu of emissions limits during startup or shutdown periods must submit specific information to the Administrator no later than 30 days prior to the anticipated date of startup or shutdown. The required information is necessary to ensure that the furnace will be properly operated during the startup or shutdown period, as applicable. The final rule establishes limits on the number of days when the owner or operator may comply with alternative work practice standards in lieu of emissions limits during startup and shutdown, depending on the type of glass furnace. Additionally, the owner or operator must maintain operating records and additional documentation as necessary to demonstrate compliance with the alternative requirements during startup or shutdown periods. For startups, the owner or operator must place the emissions control system in operation as soon as technologically feasible to minimize emissions. For shutdowns, the owner or operator must operate the emissions control system whenever technologically feasible to minimize emissions.

For periods of idling, the owner or operator of an affected unit may comply with an alternative emissions limit calculated in accordance with a specific equation to limit emissions to an amount (in pounds per day) that reflects the furnace's permitted production capacity in tons of glass produced per day. Additionally, the owner or operator must maintain operating records as necessary to demonstrate compliance with the alternative emissions limitations during idling periods. During idling, the owner or operator must operate the emissions control system to minimize emissions whenever technologically feasible.

All-Electric Glass Furnaces

The EPA solicited comment on whether it is feasible or appropriate to phase out and retire existing glass manufacturing furnaces in the affected states and replace them with more energy efficient and less emitting units like all-electric melter installations. The EPA also requested comment on the time needed to complete such a task. All-electric melters are glass melting furnaces in which all the heat required for melting is provided by electric current from electrodes submerged in the molten glass.[393] The EPA received numerous comments from the glass industry regarding their concerns with replacing an existing glass manufacturing furnace with an all-electric melter. The commenters stated that various operational restrictions present within all-electric furnaces prevent these units from being implemented throughout the industry, including limited glass production output, reduced glass furnace life, and increased glass plant operating cost due to high levels of electric current usage. Based on the EPA's review of comments submitted on this issue, the EPA has decided not to establish any requirements to replace existing glass manufacturing furnaces with all-electric furnaces at this time. We provide in the following paragraphs a summary of the comments and the EPA's responses thereto.

Comment: One commenter stated that the lifetime of an all-electric glass melting furnace is only about three to five years before it must be rebricked, compared to well-maintained natural gas or hybrid furnace that may be operated continuously for as long as fifteen to twenty years between rebricking events. The commenter also states that electric furnaces for manufacture of glass containers are limited to a maximum glass production of about 120 tons per day, which is a stark contrast to large natural gas fired glass melting furnaces, which are capable of producing over 400 tons of glass per day. The commenter also stated that the cullet percentage is greatly reduced in all-electric furnaces which increases energy consumption in the affected facility.

Response: At proposal, the EPA solicited comment on whether it is feasible or appropriate for owners or operators of existing glass manufacturing furnaces to phase out and retire their units and replace them with less emitting units like all-electric furnace installations. As explained in the Final Non-EGU Sectors TSD, over the last few decades the demand for flat, container, and pressed/blown glass has continued to grow annually. Nitrogen oxides remain one of the primary air pollutants emitted during the production and manufacturing of glass products. However, no current Federal CAA regulation controls NO_X emissions from the industry on a category-wide basis.[394] Therefore, the glass manufacturing industry has conducted various pollution prevention and research efforts to help identify preferred techniques for the control of NO_X. Some of these studies revealed recent trends to control NO_X emissions in the glass industry, including the use of all-electric glass furnaces. We understand based on the comments received from the glass manufacturing industry that significant differences exist in the design, configuration, age, and replacement cost of glass furnaces and in the feasibility of controls and raw material compositions. These differences as well as the production limitations present with all-electric furnaces create difficulties in implementing all-electric furnaces across the industry while keeping up with glass product demands. Therefore, the EPA is not mandating any requirement for owners or operators of existing glass manufacturing furnaces to replace their units with all-electric furnaces.

Combustion Modification and Post-Combustion Modification Control Devices

According to the EPA's ''Alternative Control Techniques Document—NO_X Emissions from Glass

[391] See Pennsylvania Code, Title 25, Part I, Subpart C, Article III, Sections 129.305–129.307 (effective June 19, 2010), available at *https://www.pacodeandbulletin.gov/Display/pacode?file=/secure/pacode/data/025/chapter129/chap129toc.html&d=reduce* and San Joaquin Valley Unified Air Pollution Control District, Rule 4354, ''Glass Melting Furnaces,'' sections 5.5–5.7 (amended May 19, 2011), available at *https://www.valleyair.org/rules/currntrules/R4354%20051911.pdf*.

[392] See 80 FR 33840, 33914 (June 12, 2015) (identifying the EPA's recommended criteria for developing and evaluating alternative emissions limitations applicable during startup and shutdown).

[393] *See* definitions in 40 CFR part 60, subpart CC.

[394] See Final Non-EGU Sectors TSD.

Manufacturing,'' [395] glass manufacturing furnaces may utilize combustion modifications equivalent to low-NO_X burners and oxy-firing. At proposal, the EPA solicited comments on whether it is feasible or appropriate to require sources with existing glass manufacturing furnaces in affected states that currently utilize these combustion modifications to add or operate a post-combustion modifications control device like SNCR or SCR to further improve their NO_X removal efficiency. The EPA received numerous comments from the glass industry that detailed the differences present in glass furnace designs, operations and finished product that influenced the type of combustion modification or post-combustion modification control device that is feasible for such unit. Several commenters have requested that the EPA focus on establishing an emissions limit rather than specifying the use of a particular control technology given the significant differences across glass furnaces. As a result of the comments received, the EPA is not specifically requiring affected units to install combustion modification and post-combustion controls to meet the finalized emissions limits. The EPA is finalizing the emissions limits as proposed, which may be met with combustion modifications (*e.g.,* low-NO_X burners, oxy-firing), process modifications (*e.g.,* modified furnace, cullet preheat), and/or post-combustion controls (SNCR or SCR) and thus provide sources some flexibility to choose the control technology that works best for their unique circumstances.

Comment: Multiple commenters responded to EPA's request for comments by stating it is unnecessary and unhelpful for the proposed rule to specify use of particular post-combustion control device. The commenters note that various flat glass furnaces have a variety of combustion and post-combustion control options. Each furnace is different in its design, operations, and finished product produced. The commenters state that it is more appropriate for EPA to establish an emissions limit in the proposed rule than it is for the EPA to specify use of a particular control technology.

Response: In response to these comments, the EPA is not establishing any requirements for affected units to install specific control technologies to meet the emissions limits. The EPA is finalizing the limits as proposed to offer sources some flexibility to choose the control technology that works best for their unique circumstances.

Compliance Assurance Requirements

The EPA proposed to require owners or operators of an affected facility that is subject to the NO_X emissions standards for glass manufacturing furnaces to install, calibrate, maintain and operate a CEMS for the measurement of NO_X emissions discharged. The EPA also solicited comments on alternative monitoring systems or methods that are equivalent to CEMS to demonstrate compliance with the emissions limits. The EPA received numerous comments from the glass industry expressing concern with any requirement to use CEMS at affected units. After review of the comments received and EPA's assessment of practices conducted within the glass manufacturing industry, the EPA is finalizing compliance assurance requirements that allow affected glass manufacturing furnaces to demonstrate compliance through annual testing or use CEMS, or similar alternative monitoring system data in lieu of a performance test. The EPA is also establishing recordkeeping provisions that require owners or operators of affected units to conduct parametric monitoring of fuel use and glass production during performance testing to assure continuous compliance on a 30-operating day rolling average.

Comment: Commenters representing the glass industry stated that a requirement to install and operate CEMS would present significant costs and technical complexities in a situation where emissions can be effectively monitored using stack testing rather than continuous monitoring. Commenters also objected to the EPA's proposal to require CEMS together with semi-annual stack testing. Commenters stated that a requirement to both operate CEMS and conduct semi-annual testing would be unnecessary and excessive and would not provide commensurate benefit unless a facility's emissions are near or above the proposed emissions limit. Commenters requested that owners or operators of affected units be allowed to use alternative monitoring systems, *e.g.,* parametric emissions monitoring. The commenters stated that parametric monitoring requires less initial and ongoing manpower requirements, has lower capital and operating costs than CEMS, does not require spare parts, and is accurate over a mapped range.

Response: The EPA is establishing compliance assurance requirements that provide flexibility to owners or operators of affected units. Compliance with the emissions limits in this final rule may be demonstrated through CEMS or via annual performance test and continuous parametric monitoring. If an affected unit does not use CEMS, the final rule requires the owner or operator to monitor and record stack exhaust gas flow rate, hourly production rate, and stack exhaust temperature during the initial performance test and subsequent annual performance tests to assure compliance with the applicable emissions limit. The owner or operator must then continuously monitor and record those parameters to demonstrate continuous compliance with the NO_X emissions limits. Affected units that operate NO_X CEMS meeting specified requirements may use CEMS data in lieu of performance testing and monitoring of operating parameters. To avoid challenges in scheduling and availability of testing firms, the annual performance test required under this final rule does not have to be performed during the ozone season.

5. Boilers at Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, Pulp, Paper, and Paperboard Mills, Iron and Steel and Ferroalloys Manufacturing, and Metal Ore Mining facilities

Applicability

The EPA is finalizing regulatory requirements for the Iron and Steel Mills and Ferroalloy Manufacturing industry, Basic Chemical Manufacturing industry, Petroleum and Coal Products Manufacturing industry, Pulp, Paper, and Paperboard Mills industry, and the Metal Ore Mining industry that apply to boilers that have a design capacity of 100 mmBtu/hr or greater. The Non-EGU Screening Assessment memorandum developed in support of Step 3 of our proposal identified emissions from large boilers in certain industries (*i.e.,* those projected to emit more than 100 tpy of NO_X in 2026) as having adverse impacts on downwind receptors. As discussed in the proposed rule, we developed applicability criteria for boilers based on design capacity (*i.e.,* heat input), rather than on potential emissions, because use of a boiler design capacity of 100 mmBtu/hr reasonably approximates the 100 tpy threshold used in the Non-EGU Screening Assessment memorandum to identify impactful boilers. In this final rule, we are establishing the heat input-based applicability criteria described in our proposal, with some adjustments as explained further in this section. Additionally, we have determined that boilers meeting these applicability

[395] EPA, Alternative Control Techniques Document—NO_X Emissions from Glass Manufacturing, EPA–453/R–94–037, June 1994.

criteria exist within the following five industries: Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, Pulp, Paper, and Paperboard Mills, Metal Ore Mining, and Iron and Steel Mills and Ferroalloy Manufacturing.

As we explained in the proposed rule, the potential emissions from industrial boilers with a design capacity of 100 mmBtu/hr or greater burning coal, residual or distillate oil, or natural gas can equal or exceed the 100 tpy threshold that we used to identify impactful boilers within the Non-EGU Screening Assessment memorandum. We are finalizing NO_X emissions limits that apply to boilers with design capacities of 100 mmBTU/hr or greater located at any of the five identified industries in any of the 20 covered states with non-EGU emissions reduction obligations. In response to comments on our proposed rule, however, the EPA is finalizing a low-use exemption for industrial boilers that operate less than 10 percent per year and provisions for EPA approval of alternative emissions limits on a case-by-case basis, where specific criteria are met. Additionally, only boilers that combust, on a BTU basis, 90 percent or more of coal, residual or distillate oil, natural gas, or combinations of these fuels are subject to the requirements of these final FIPs.

The EPA has determined that boilers meeting the applicability criteria of this section exist within the five industrial sectors identified in Table VI.C.5–1:

TABLE VI.C.5—1: NON-EGU INDUSTRIES WITH LARGE BOILERS AND ASSOCIATED NAICS CODES

Industry	NAICS code
Basic Chemical Manufacturing	3251xx
Petroleum and Coal Products Manufacturing	3241xx
Pulp, Paper, and Paperboard Mills	3221xx
Iron and Steel and Ferroalloys Manufacturing	3311xx
Metal Ore Mining	2122xx

Comment: Several commenters requested that the EPA establish PTE-based applicability criteria for boilers as it had proposed to do for other non-EGU sectors and stated that using heat input as the basis for determining applicability would result in low-emitting boilers being subject to the final rule's control requirements. Commenters stated that the EPA should provide a low-use exemption for infrequently run units because these units produce a lower amount of emissions.

Response: The EPA is finalizing applicability criteria for boilers based on boiler design capacity for a number of reasons. First, Federal emissions standards applicable to boilers[396] and all of the state RACT rules that we reviewed contain applicability criteria based on boiler design capacity. Second, as explained in the Final Non-EGU Sectors TSD, most boilers with design capacities of 100 mmBTU/hr or greater that are fueled by coal, oil, or gas have the potential to emit 100 tpy or more of NO_X. Thus, use of a boiler design capacity of 100 mmBtu/hr for applicability purposes reasonably approximates the 100 tpy threshold used in the Non-EGU Screening Assessment memorandum to identify impactful boilers. Finally, use of a boiler's design capacity for applicability purposes facilitates applicability determinations given that a boiler's design capacity is, in most cases, clearly indicated by the manufacture on the unit's nameplate.

In response to the comments expressing concern that infrequently-operated boilers would be captured by the EPA's proposed applicability criteria, the EPA is finalizing a low-use exemption for industrial boilers that operate less than 10 percent per year on an hourly basis, based on the three most recent years of use and no more than 20 percent in any one of the three years. Such boilers will be exempt from the emissions limits in these FIPs provided they operate less than 10 percent per year, on an hourly basis, based on the three most recent years of use and no more than 20 percent in any one of the three years, but will have recordkeeping obligations. The EPA finds it appropriate to exempt such low-use boilers from the emissions limits in this final rule because the amount of air pollution emitted from a boiler is directly related to its operational hours, and installation of controls on infrequently operated units results in reduced air quality benefits.

Comment: Commenters asked whether the EPA's proposed emissions limits for boilers would apply to emissions units that burn fuels other than coal, residual or distillate oil, or natural gas. For example, one commenter stated that some biomass boilers start up by co-firing oil or gas and that some NO_X controls such as low-NO_X burners (LNB) cannot be used on biomass boilers. The commenter requested clarification on whether boilers burning biomass would be covered by the EPA's proposed requirements. Other commenters noted that some industrial boilers burn natural gas in conjunction with other gaseous fuels, such as hydrogen/methane off-gas and vent gas from various on-site processes, and may not be able to meet the EPA's proposed 0.08 lb/mmBtu NO_X emissions limit for boilers burning natural gas. One commenter stated that it operated a boiler that burns hazardous waste and is subject to 40 CFR part 63, subpart EEE, National Emission Standards for Hazardous Air Pollutants from Hazardous Waste Combustors, and that this boiler uses natural gas for start-up and at other times to stabilize operations but also combusts other fuels such as liquid waste. The commenter asserted that such boilers should not be covered by the final rule.

Response: In recognition and consideration of comments received on our proposal, the EPA is finalizing requirements for boilers that apply only to boilers burning 90 percent or more coal, residual or distillate oil, or natural gas or combinations of these fuels on a heat-input basis. Public commenters presented information indicating that the burning of fuels other than coal, residual or distillate oil, or natural gas at levels exceeding 10 percent may interfere with the functions of the control technologies that may be necessary to the meet the final rule, like SCR. The EPA does not have sufficient information at this time to conclude that units burning more than 10 percent fuels other than coal, residual or distillate oil, or natural gas can operate the necessary controls effectively and at a reasonable cost. Therefore, boilers that burn greater than 10 percent fuels other than coal, residual or distillate oil,

[396] *See, e.g.,* 40 CFR 60.44b (subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units).

natural gas, or combinations of these three fuels are not subject to the emissions limits and other requirements of this final rule.

Comment: Some commenters claimed that the EPA cannot include emissions limits for boilers that burn combinations of coal, residual or distillate oil, and natural gas, because the EPA did not propose limits for such boilers. Other commenters suggested it would be appropriate to establish emissions limits for such boilers as long as the EPA provides criteria for establishing such emissions limits.

Response: The EPA disagrees with the claim that boilers burning combinations of coal, residual or distillate oil, or natural gas cannot be covered by the final FIP because the EPA did not propose specific emissions limits for these boilers and agrees with commenters who stated that the EPA's proposed emissions limits can be extended to such boilers provided the EPA provides criteria for doing so. The applicability criteria in the final rule cover boilers burning combinations of coal, residual or distillate oil, or natural gas and include a methodology for determining the emissions limits for such units based on a simple formula that correlates the amount of heat input expended while burning each fuel with the corresponding emissions limit for that particular fuel. For example, a boiler with a heat input of 85 percent natural gas and 15 percent distillate oil would be subject to an emissions limit derived by multiplying the natural gas emissions limit by 0.85 and adding to that the distillate oil emissions limit multiplied by 0.15. Thus calculated, the NO_X emissions limits for boilers burning combinations of coal, residual or distillate oil, or natural gas are consistent with the NO_X emissions limits identified in our proposed rule for each of these individual fuels.

Emissions Limitations and Rationale

The EPA is finalizing all of the proposed NO_X emissions limits for industrial boilers and adding a formula for calculating emissions limits for multi-fueled units as shown in Table VI.C.5–2. The emissions limits apply to boilers with design capacities of 100 mmBtu/hr or greater located at any of the five industries identified in Table II.A–1 within any of the 20 states covered by the non-EGU requirements of this final rule.

TABLE VI.C.5–2—NO_X EMISSIONS LIMITS FOR BOILERS >100 mmBtu/hr

[Based on a 30-day rolling average]

Unit type	Emissions limit (lbs NO_X/mmBtu)
Coal	0.20.
Residual oil	0.20.
Distillate oil	0.12.
Natural gas	0.08.
Multi-fueled unit	Limit derived by formula based on heat input contribution from each fuel.

Additional information on the EPA's derivation of these proposed emissions rates for boilers is provided in the Final Non-EGU Sectors TSD.

Comment: Some commenters noted that many boilers are already subject to other state and Federal controls, and that programs such as RACT, NSR, BACT, NSPS, and maximum achievable control technology (MACT) are all achieving emissions reductions from boilers.

Response: The EPA acknowledges that some affected units may already be meeting the emissions limits established in this rule as a result of controls installed to comply with other regulatory programs, such as the CAA's RACT requirements. However, emissions from the universe of boilers subject to the applicability requirements of this final rule are not being uniformly reduced by these programs to the same extent that the limits we are adopting will require, nor for the same reason, which is to mitigate the impact of emissions from upwind sources on downwind locations that are experiencing air quality problems. The EPA has determined that the limits we are finalizing in this action are readily achievable and are already required in practice in many parts of the country.

Regarding RACT controls, some of the sources covered by the final rule are not subject to RACT requirements because RACT is only applicable to sources located in ozone nonattainment areas and in the OTR, and many sources covered by the final rule are not located within such jurisdictions. Regarding sources that are subject to RACT, we note that unlike RACT requirements applicable to sources of VOCs, where a majority of such sources are covered by state RACT rules adopted to conform with uniform ''presumptive'' limits contained within the EPA's Control Technique Guidelines (CTGs), in most cases presumptive NO_X emissions limits have not been established for industrial sources of this pollutant. In light of this, NO_X RACT requirements are primarily determined on a state-by-state basis and exhibit a range of stringencies as determined by each state. Additionally, RACT requirements tend to become more stringent with the passage of time as existing control options are improved, and new options become available. Thus, older RACT determinations may not be as stringent as more recent determinations made for similar equipment types. As noted in our proposal, we based our NO_X emissions limits for coal, residual or distillate oil, and natural gas-fired industrial boilers on RACT limits that are already in place in many areas of the country.

Regarding NSR control requirements, we note that the NSR program was created by the 1977 amendments to the CAA and applies only to new or modified stationary sources. Many of the boilers covered by the applicability requirement of this final rule were initially installed or last modified prior to 1977 and have not undergone NSR analysis, such as a BACT analysis for sources located within an attainment area or a LAER analysis for sources located within nonattainment areas. Additionally, BACT and LAER determinations made many years ago are not likely to be as stringent as more recent determinations.

Regarding NSPS requirements, 40 CFR part 60, subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, contains NO_X emissions limits for boilers with capacities of 100 mmBTU/hr or greater that were constructed or modified after June 19, 1984, and so boilers constructed or modified prior to that date are not subject to its requirements. Additionally, the limits for coal, residual or distillate oil, and gas-fired units are not as stringent as more recent limits adopted by states pursuant to RACT control obligations.

Lastly, MACT controls are primarily designed to reduce emissions of hazardous air pollutants, not to reduce NO_X emissions. We anticipate the MACT program's boiler tune-up requirement should reduce NO_X emissions to some extent, but not to the extent that compliance with the limits adopted within this final rule will achieve.

Comment: One commenter noted that a 2017 OTC survey found that boilers, including those used in the paper products, chemical, and petroleum industries, are already required to achieve more stringent limits, and pointed to limits for distillate oil that are lower than what the EPA considered in developing the proposal. The commenter also noted that California's South Coast Air Quality Management District has adopted a facility-wide NO_X emissions limit of 0.03 lb/mmBtu at petroleum refineries. The commenter noted that CEMs data shows a residual oil-fired boiler at the Ravenswood Steam Plant in New York achieves an average NO_X emissions rate of 0.0716 lb NO_X/MMBtu and that CEMS data shows that a gas-fired boiler in Johnsonville, Tennessee, achieves an average NO_X emissions rate of 0.0058 lb NO_X/mmBTU. Regarding coal-fired boilers, the commenter stated that a coal boiler at the Ingredion Incorporated Argo Plant in Illinois achieves an average NO_X emissions rate of 0.1153 lb NO_X/MMBtu with selective non-catalytic control technology, and the Axiall Corporation facility in West Virginia achieves a 0.1162 lb/mmBtu using low-NO_X burner technology with overfire air. The commenter also noted that more than half of the gas-fired boilers included in the air markets program database already emit NO_X at rates below the EPA's proposed emissions rate, and that the RACT/BACT/LAER Clearinghouse (RBLC) shows more stringent limits for gas boilers than the limits the EPA proposed, with many facilities being required to meet a NO_X limit of less than 0.0400 lb/mmBtu.

Response: The EPA's intent was not to set the NO_X emissions limits for coal, residual or distillate oil, and natural gas-fired boilers to match the lowest levels required elsewhere by state or local authorities, but rather to establish limits that are commensurate with broadly applicable RACT limits currently in place in a number of states as noted within our proposal. The limits we selected were not the most stringent of the state RACT rules we reviewed but were relatively close to that value. We did not select the most stringent limits because such limits may reflect case-specific technological and economic feasibility considerations that do not apply more broadly across the industry. Furthermore, although the EPA acknowledges that some industrial boilers powered by coal, residual or distillate oil, natural gas, or combinations of these fuels can meet very low NO_X emissions limits as noted by the commenter, it is unlikely that all such units could meet these limits given case-specific considerations such as boiler design and operation, some of which limit the types of control technology that may be available to a particular unit.

a. Coal-Fired Industrial Boilers

As we proposed, coal-fired industrial boilers subject to the applicability requirements of this section are required to meet a NO_X emissions limit of 0.2 lb/mmBtu on a 30-day rolling average basis. Various forms of combustion and post-combustion NO_X control technology exist that should enable most facilities to retrofit with equipment to meet this emissions limit. As we explained in our proposal, many states containing ozone nonattainment areas or located within the OTR have already adopted RACT emissions limits similar to or more stringent than the limits in this final rule, and most of those RACT limits apply statewide and extend to boilers located at commercial and institutional facilities, not just to boilers located in the industrial sector.

Comment: One commenter noted that the coal-fired boilers it operates already use combustion controls to reduce NO_X emissions and contended that the effectiveness of SNCR on these boilers is unknown but would likely be on the low end of the control effectiveness range because they experience variable loads, which would compromise the proper functioning of an SNCR control system. The commenter stated that the only way their coal-fired boilers would be able to comply with the EPA's proposed NO_X limit would be to install SCR. The commenter added that for coal-fired industrial boilers with a heat input rating of 100 MMBtu/hr or more, a review of the available RBLC records indicates that out of the 23 RBLC entries identified, nine units (less than half) were subject to an emissions limit at or below 0.2 lb/mmBtu, and eight of these nine units were equipped with SNCR. The commenter stated that based on a review of the available data in the RBLC and given the technical difficulties and low control efficiencies when applying SNCR to swing boilers, the EPA's proposed limit for coal firing does not appear achievable for industrial coal-fired boilers that experience load swings unless SCR is installed. Other commenters stated that while there have been recent advancements in SNCR technology, such as the setting up of multiple injection grids and the addition of sophisticated CEMs-based feedback loops, implementing SNCR on industrial load-following boilers continues to pose several technical challenges, including lack of achievement of optimal temperature range for the reduction reactions to successfully complete, and inadequate reagent dispersion in the injection region due to boiler design which can lead to significant amounts of unreacted ammonia exhausted to the atmosphere (*i.e.,* large ammonia slip). The commenter noted that at least one pulp mill boiler had to abandon its SNCR system due to problems caused by poor dispersion of the reagent within the boiler, and that SNCR has yet to be successfully demonstrated for a pulp mill boiler with constant swing loads.

Response: To the extent the commenter's concerns pertain primarily to SNCR control technology, we note that the final rule does not mandate the use of any particular type of control technology and that other types of control equipment such as SCR should be examined as a means for meeting the final emissions limits. The EPA acknowledges that some coal-fired industrial boilers subject to this section of the final rule may need to install SCR to meet the NO_X emissions limits. This is reflected in our evaluation of costs for the non-EGU sector contained within the Non-EGU Screening Assessment memorandum and the cost calculations for the final rule discussed in section V and the *Memo to Docket—Non-EGU Applicability Requirements and Estimate Emissions Reductions and Costs.* We note that although the RBLC contains information on emissions limits and control technology for some units, it only provides information on a relatively small number of units subject to NO_X emissions limits and operating NO_X controls. Additionally, our final rule provides an exemption for units that operate infrequently (*i.e.,* ''low-use boilers''), and also allows a facility owner or operator to submit a request for a case-by-case alternative emissions limit in cases where compliance with the emissions limit in this final rule is technically impossible or would result in extreme economic hardship. We note that non-EGU boilers share many similarities with EGU boilers, many of which already operate SCR to control NO_X emissions or will be required to install and operate SCR systems under the requirements for EGUs contained in this final rule. Lastly, we note that information collected during the development of updates to the EPA's MACT requirements for industrial, commercial, and institutional (ICI) boilers indicates that over 150 ICI boilers have installed SCR control systems to reduce their NO_X emissions. This information is available in the docket for this final rule.

All affected units must install and operate NO_X control equipment as necessary to meet the applicable emissions limits in the final rule, except that if the owner or operator requests, and the EPA approves, a case-by-case emissions limit based on a showing of technical impossibility or extreme economic hardship, the affected unit would be required to comply with the EPA-approved case-by-case emissions limit instead.

b. Residual or Distillate Oil-Fired Industrial Boilers

Most oil-fired boilers are fueled by either residual (heavy) oil or distillate (light) oil. We proposed a NO_X emissions limit of 0.2 lb/mmBtu [397] for residual oil-fired boilers and proposed a NO_X emissions limit of 0.12 lb/mmBtu for distillate oil-fired boilers. We are finalizing both limits as proposed, based on a 30-day rolling average. As with coal-fired industrial boilers, a number of combustion and post-combustion NO_X control technologies exist that should generally enable facilities meeting the applicability criteria of this section to meet these emissions limits, and the Final Non-EGU Sectors TSD identifies numerous states that have already adopted emissions limits similar to the limits in this final rule. There are relatively few boilers fueled by residual or distillate oil within the industries affected by this final rule that meet the applicability criteria of this section, and we received relatively few comments regarding our proposed emissions limits for them.

c. Natural Gas-Fired Industrial Boilers

We proposed a NO_X emissions limit of 0.08 lb/mmBtu based on a 30-day rolling average for natural gas-fired boilers meeting the applicability criteria of this section, and we are finalizing this emissions limit and averaging time as proposed. As explained in our proposal, numerous combustion and post-combustion NO_X control technologies exist that should generally enable facilities meeting the applicability criteria of this section to meet this emissions limit. Additionally, many states have already adopted emissions limits similar to the emissions limit in this final rule, and some natural gas-fired industrial boilers may be able to meet the 0.08 lb/mmBtu emissions limit by modifying existing NO_X control equipment installed to meet the requirements in 40 CFR 60.44b (subpart Db of 40 CFR part 60, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units), which already requires that natural gas-fired units meet a NO_X emissions limit of between 0.1 to 0.2 lbs/MMBtu.

Compliance Assurance Requirements

We proposed compliance provisions for boilers subject to the requirements of this section similar to the emissions monitoring requirements found in 40 CFR 60.45 (subpart D of 40 CFR part 60, Standards of Performance for Fossil-Fuel-Fired Steam Generators). Those requirements include, among other provisions, the performance of an initial compliance test and installation of a CEMS unless the initial performance test indicates the unit's emissions rate is 70 percent or less of the emissions limit in this final rule. We received a number of comments on this portion of our proposal and provide responses to some of these comments in the following paragraphs. Our full responses to comments are provided in the response to comments document included in the docket for this action.

Comment: A number of commenters stated that CEMS monitoring is too expensive and unnecessary for ensuring compliance with the emissions limits for boilers and requested that alternative monitoring techniques be allowed.

Response: The EPA acknowledges that the installation and operation of CEMs systems is more expensive than other monitoring techniques and may not be necessary for smaller sized boilers that typically produce less emissions than larger ones. In response to these comments, we have modified the monitoring requirements in the final rule such that boilers rated with heat-input capacities less than 250 mmBTU/hr can demonstrate compliance by conducting an annual stack test as an alternative to monitoring using a CEMs system and by complying with the provisions of a monitoring plan meeting specific criteria that enables the facility owner or operator to demonstrate continuous compliance with the emissions limits of this final rule.

Comment: One commenter stated that the proposed reporting obligations require the submittal of excess emissions reports, continuous monitoring, and quarterly emissions reports. The commenter suggested that since the NO_X emissions standards only apply during the ozone season (May 1–September 30), the reporting requirements should only apply during the second and third quarters of the year and should require that only emissions and monitoring data from this time period be included in these reports.

Response: In response to these comments, the EPA is finalizing recordkeeping, monitoring, and reporting requirements that are designed to ensure compliance with the applicable emissions limits only during the ozone season. Additionally, the final rule requires annual reports rather than the proposed quarterly reports as annual reports are adequate to determine compliance with the emissions limits during the ozone season.

Comment: A number of commenters stated that some of their boilers that may potentially be subject to a final FIP already have a NO_X CEMS installed and requested that the EPA clarify whether a 30-day initial compliance test is required in such cases.

Response: The EPA's final rule provides that in instances where a boiler meeting the applicability requirements of this section has already installed a NO_X CEMs that meets the requirements for such equipment located within 40 CFR 60.13 or 40 CFR part 75, Continuous Emissions Monitoring, pursuant to a federally enforceable requirement, a 30-day initial compliance test is not required.

Comment: One commenter stated that § 52.45(d) of the EPA's proposed rule included requirements to complete an initial 30-day compliance test within 90 days of installing pollution control equipment but did not specify whether the test must be complete prior to the May 1, 2026, ozone season or by some later date.

Response: In response to this comment, the EPA is finalizing provisions requiring that initial compliance tests occur prior to the May 1, 2026 compliance date.

6. Municipal Waste Combustors

Applicability

The EPA is finalizing regulatory requirements that apply to municipal solid waste combustors located in a state subject to the non-EGU requirements of this final rule (*i.e.,* the 20 states with linkages that persist in 2026 as identified in section II.B) and

[397] Section 52.45(c) of the regulatory text in our proposed rule identified a proposed emissions limit of 0.15 lb/mmBtu for residual oil-fired boilers, but the emissions limit that we intended to propose for this equipment and discussed both in the preamble to the proposed rule and in the TSD supporting the proposed rule was 0.20 lb/mmBtu.

that combust greater than or equal to 250 tons per day of municipal solid waste (''affected units''). *See* 40 CFR 52.46(d) for guidelines on calculating municipal waste combustor unit capacity. This applicability threshold was supported by commenters and is consistent with the applicability criteria in 40 CFR part 60, subpart Eb, Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Large Municipal Waste Combustors. State RACT rules for MWCs and the OTC MWC report similarly define large MWC units as units with a combustion capacity greater than or equal to 250 tons per day.

Across the 20 states subject to the non-EGU requirements, this applicability threshold captures 28 MWC facilities with a total of 80 affected units. The identified affected units include mass burn waterwall units, mass burn rotary waterwall units, refuse derived fuel (RDF) units, and one CLEERGAS™ (''Covanta Low Emissions Energy Recovery Gasification'') modular system.[398] The EPA analyzed actual emissions from the facilities captured by this threshold and found that on average, a unit with a design capacity of 250 tons per day has a PTE of approximately 138 tons per year,[399] which is similar to the PTE threshold applied to other non-EGU sources under this rulemaking.

Emissions Limitations and Rationale

Based on the available information for this industry, including information provided during the public comment period, the OTC MWC Report, a review of State and local RACT rules that apply to MWCs, and active air permits issued to MWCs, the EPA is finalizing the following emissions limits for municipal solid waste combustors.

TABLE VI.C.6–1—NO_X EMISSIONS LIMITS FOR LARGE MUNICIPAL WASTE COMBUSTORS

NO_X Limit (ppmvd) corrected to 7 percent oxygen	Averaging period
110	24-hour.
105	30-day.

At proposal, the EPA noted that the NO_X limits for large MWCs constructed on or before September 20, 1994 under NSPS subpart Cb are found within Tables 1 and 2 of 40 CFR 60.39b and range from 165 to 250 ppm depending on the combustor design type. The NO_X limits for large MWCs constructed after September 20, 1994 or for which modification or reconstruction is commenced after June 19, 1996 under NSPS subpart Eb are found at 40 CFR 60.52b(d) and are 180 ppm during a unit's first year of operation and 150 ppm afterwards, applicable across all combustor types. These limits correspond to NO_X emissions rates of 0.31 and 0.26 lb/mmBtu, respectively. In reviewing active air permits for MWCs, the EPA found that most MWCs are meeting emissions limits similar to those reflected in the applicable NSPS.[400]

The EPA also cited the OTC's MWC report that evaluated the emissions reduction potential of large MWCs located in the OTR from two different control levels, one based on a NO_X concentration of 105 to 110 ppm, and another based on a limit of 130 ppm. The OTC MWC report found that a control level of 105 ppmvd on a 30-day rolling average basis and a 110 ppmvd on a 24-hour block averaging period would reduce NO_X emissions from MWCs by approximately 7,300 tons annually, and that a limit of 130 ppmvd on a 30 day-average could achieve a 4,000 ton reduction. The OTR MWC Report noted that at the time of publication, eight MWC units were already subject to permit limits of 110 ppm, seven in Virginia, and one in Florida. In consideration of control costs, the report cited multiple studies evaluating MWCs similar in design to the large MWCs in the OTR and found NO_X reductions could be achieved at costs ranging from $2,900 to $6,600 per ton of NO_X reduced.

To further inform the EPA's consideration of emissions limits for MWCs, the EPA requested comment on the emissions limit and averaging time MWCs should be required to meet, and specifically whether the EPA should adopt emissions rates of 105 ppmvd on a 30-day rolling averaging basis and 110 ppmvd on a 24-hour block averaging basis.

Comment: The agency received several comments regarding emissions limits and averaging time for MWCs. Many commenters asserted that the EPA should set a 24-hour emissions limit no higher than 110 ppm, noting that recent studies have shown that there are a variety of technologies that can help a wide range of MWC types achieve this limit at costs that are significantly below the $7,500/ton cost effectiveness threshold that the EPA identified at proposal. Some commenters confirmed the accuracy of the OTC workgroup's estimated cost of controls for reducing NO_X emissions from MWCs of $2,900 to $6,600 while others stated that the cost of controls is well below $7,500. One commenter asserted that the EPA should set a 24-hour NO_X emissions limit of 50 ppmvd for MWCs, which could be achieved by the installation of SCR technology. Alternatively, the commenters stated that the EPA should set a 24-hour emissions limit no higher than 110 ppm based on less effective, though still widely available, control technology. Although some commenters stated that MWCs should not be included in the rulemaking, no commenters specifically identified units or categories of units that could not achieve emissions limits of 105 ppmvd on a 30-day rolling averaging basis and 110 ppmvd on a 24-hour block averaging basis.

Response: The EPA recognizes that there have been instances where MWCs have installed SCR and achieved emissions rates of 50 ppmvd on a 24-hr averaging basis and 45 ppmvd on a 30-day rolling averaging basis with cost effectiveness estimates around $10,296/ton to $12,779/ton of NO_X reduced. Given uncertainties pertaining to whether SCR can be installed on all types of MWCs, the EPA has decided not to establish emissions limits as low as 50 ppmvd for MWCs using SCR at this time. However, as generally supported by most commenters, the EPA is finalizing emissions limits of 105 ppmvd at 7 percent oxygen (O_2) on a 30-day rolling average and 110 ppmvd at 7 percent O_2 on a 24-hour block average that apply at all times except during periods of startup and shutdown. The EPA recognizes that the final emissions limits for steady-state operations cannot be achieved during periods of startup, shutdown, and malfunction. This is primarily due to the fact that during periods of startup and shutdown, additional ambient air is introduced into the units, resulting in higher oxygen concentrations. Therefore, the EPA is finalizing provisions applicable during periods of startup and shutdown that do not require correction of CEMS data to 7 percent oxygen but do require that such data be measured at stack oxygen content. This approach is consistent with EPA regulations applicable during startup and shutdown periods for other solid-waste incinerators under the NSPS for Commercial and Industrial Solid Waste Incineration Units. *See* 40 CFR part 60, subparts CCCC and DDDD.

[398] *See* the Final Non-EGU Sectors TSD for additional information on this inventory.

[399] *See* the Final Non-EGU Sectors TSD for additional information on the calculation of PTE for large MWCs.

[400] For further discussion of the permits reviewed, see the Final Non-EGU Sectors TSD.

Information received from public commenters generally aligned with the results from studies showing that the emissions limits of 105 ppmvd on a 30-day rolling averaging basis and 110 ppmvd on a 24-hour block averaging basis can be reached using ASNCR or low NO_X technology in addition to SNCR.[401] The EPA recognizes that not all units can implement low NO_X technology, including those using Aireal grate technology, those operating RFD units, and those with rotary combustor units. Of the 80 affected MWC units that the EPA identified, nine units across two facilities are classified as rotary combustors, four units at a single facility are classified as RDF, and no units captured are classified as using Aireal grate technology. One affected unit is classified as CLEERGAS gasification while the remaining 64 affected units are classified as mass burn waterwall combustors, which have not been explicitly identified as units unable to install low NO_X technology. For those units unable to install low NO_X technology or SNCR, the EPA has identified ASCNR as an alternative control technology that has been shown to enable units to achieve emissions limits of 105 ppmvd on a 30-day rolling averaging basis and 110 ppmvd on a 24-hour block averaging basis, either as a new retrofit technology or as a significant upgrade to existing SNCR. The EPA finds that the availability of ASNCR or SNCR and low NO_X burners provides sufficient flexibility for MWCs to meet the emissions limits in the final rule, especially considering 74 of the 80 affected units already have SNCR installed. Although there is uncertainty on the cost effectiveness of ASNCR for achieving significant NO_X reductions in small MWCs, small MWCs that combust less than 250 tons per day of municipal solid waste are not included in this rulemaking.

While commenters noted discrepancies across cost effectiveness values for specific types of control technology, no commenters specifically indicated that emissions control technology could not be cost effectively installed on large MWCs to achieve an emissions limit of 105 ppmvd on a 30-day rolling averaging basis and 110 ppmvd on a 24-hour block averaging basis. Studies show that these limits can be achieved through a variety of emissions controls, including ASNCR and the addition of low NO_X technology to existing SNCR.[402] Of the 80 MWC units subject to this rule, 55 units already have SNCR installed, 16 units already have SNCR and low NO_X technology installed, and three units already have ASNCR installed. Applying the cost values provided in the OTC's MWC report to the MWC inventory in section 7 of the Final Non-EGU Sectors TSD, the estimated weighted average cost effectiveness of applying advanced SNCR to units with and without existing SNCR and adding low NO_X technology to eligible units with SNCR was found to be approximately $7,929.02/ton.[403] This value is in line with the control technology costs for other non-EGU sectors and the EGU costs associated with this final rule.

Compliance Assurance Requirements

In this final rule, the EPA is establishing compliance requirements for MWCs similar to the NSPS requirements for large MWCs under 40 CFR part 60, subpart Eb. Those requirements include, among other provisions, the performance of an initial performance test and installation of a CEMS. At proposal, the EPA requested comment on whether it would be appropriate to rely on existing testing, monitoring, recordkeeping, and reporting requirements for MWCs under applicable NSPS or other requirements.

Comment: Some commenters noted that all large MWCs are already required to use CEMS to demonstrate compliance with NO_X limits under the NSPS program. These commenters asserted that the EPA should improve electronic reporting requirements beyond current requirements in the NSPS. The commenters suggested that an owner or operator of an MWC subject to a limit under the final rule should be required to report NO_X CEMS data electronically at least annually to the EPA's CEDRI and any other database that the EPA will utilize when considering revisions to the NSPS for large MWCs. The commenters asserted that MWC operators should be required to report NO_X CEMS data to the EPA's Clean Air Markets database, to allow the public access to MWC CEMS data on a large scale for the first time.

Response: The EPA is finalizing provisions that require MWCs subject to the requirements of this section to install, calibrate, maintain, and operate a CEMS for the measurement of NO_X emissions discharged into the atmosphere from the affected facility. This is consistent with NSPS requirements for large MWCs under 40 CFR part 60, subparts Ea and Eb, and state RACT rules that are applicable to MWCs in many of the states covered under this rulemaking.[404] Additionally, each emissions unit will be required to conduct an initial performance test. With regard to electronic reporting, the final rule requires performance tests and reports, including CEMS data, to be submitted to CEDRI, as required for all non-EGU industries covered by this final rule.

D. Submitting a SIP

A state may submit a SIP at any time to address CAA requirements that are covered by a FIP, and if the EPA approves the SIP it would replace the FIP, in whole or in part, as appropriate. As discussed in this section, states may opt for one of several alternatives that the EPA has provided to take over all or portions of the FIP. However, as discussed in greater detail further in this section, the EPA also recognizes that states retain the discretion to develop SIPs to replace a FIP under approaches that differ from those the EPA has finalized.

The EPA has established certain specialized provisions for replacing FIPs with SIPs within all the CSAPR trading programs, including the use of so-called ''abbreviated SIPs'' and ''full SIPs,'' *see* 40 CFR 52.38(a)(4) and (5) and (b)(4), (5), (8), (9), (11), and (12); 40 CFR 52.39(e), (f), (h), and (i). For a state to remove all FIP provisions through an approved SIP revision, a state would need to address all of the required reductions addressed by the FIP for that state, *i.e.,* reductions achieved through both EGU control and non-EGU control,

[401] The only demonstrated use of low NO_X technology in addition to SNCR at MWC facilities is at Covanta facilities using Covanta's proprietary low NO_X combustion system (LN™). For the purpose of this rule, EPA is assuming Covanta facilities will take advantage of this technology and others will use ASNCR. However, other iterations of low NO_X technology could become available, or facilities could work with Covanta to apply this technology to their units.

[402] *See* OTC MWC Report at 6–7; Trinity Consultants, *Project Report Covanta Alexandria/ Arlington, Inc., Reasonably Available Control Technology Determination for NO_X* (September 2017); Trinity Consultants, *Project Report Covanta Fairfax, Inc., Reasonably Available Control Technology Determination for NO_X* (September 2017); Babcock Power Environmental, *Waste to Energy NO_X* Feasibility Study, Prepared for: Wheelabrator Technologies Baltimore Waste to Energy Facility Baltimore, MD (February 20, 2020); White, M., Goff, S., Deduck, S., Gohlke, O., *New Process for Achieving Very Low NO_X, Proceedings of the 17th Annual North American Waste-to-Energy Conference, NAWTEC17* (May 2009); Letter from the State of New Jersey to Michael Klein, In Rreference to Covanta Energy Group, Inc. Essex County Resource Recovery Facility, Newark Annual Stack Test Program (March 14, 2019).

[403] See Final Non-EGU Sectors TSD for more information on these cost effectiveness estimates were generated.

[404] For examples of RACT provisions applicable to MWCs that require CEMS, see Regulations of Connecticut State Agencies section 22a–174–22e; and Virginia Administrative Code section 5–40–6730, subsection (D).

as applicable to that state. Additionally, tribes in Indian country within the geographic scope of this rule may elect to work with EPA under the Tribal Authority Rule to replace the FIP for areas of Indian country, in whole or in part, with a tribal implementation plan or reasonably severable portions of a tribal implementation plan.

Under the FIPs for the 22 states whose EGUs are required to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program with the modifications finalized in this rule, EPA continues to offer ''abbreviated'' and ''full'' SIP options for states. An ''abbreviated SIP'' allows a state to submit a SIP revision that establishes state-determined allowance allocation provisions replacing the default FIP allocation provisions but leaving the remaining FIP provisions in place. A ''full SIP'' allows a state to adopt a trading program meeting certain requirements that allow sources in the state to continue to use the EPA-administered trading program through an approved SIP revision, rather than a FIP. In addition, as under past CSAPR rulemakings, states have the option to adopt state-determined allowance allocations for existing units for the second control period under this rule—in this case, the 2024 control period—through streamlined SIP revisions. *See* 76 FR 48326–48332 for additional discussion of full and abbreviated SIP options; *see also* 40 CFR 52.38(b).

Comments: Some commenters alleged that by taking this action, EPA is depriving states of the ability to develop SIPs to implement good neighbor obligations for the 2015 ozone NAAQS or from choosing their own compliance strategies. Commenters also claimed that the EPA cannot require states to implement emissions reductions equivalent to the emissions control stringency that the EPA determined at Step 3 if their proposed SIPs are otherwise shown to be adequate to eliminate significant contribution. Other commenters raised concerns that the trading program enhancements for EGUs made it too uncertain what a state could develop as an approvable replacement SIP. At least one commenter argued that the EPA must give states a single, mass-based emissions budget so that they can understand how to replace the FIP with a SIP.

Response: The EPA disagrees that it is depriving States of the opportunity to replace the FIP with a SIP or preventing states from targeting alternative emissions reductions strategies that can be shown to be equivalent to the FIP. States have always possessed the authority and the opportunity to revise their SIPs at any point. The EPA has repeatedly emphasized that states are free to develop a SIP revision to replace a transport FIP and submit that to the EPA for approval, and this remains true. *See* 87 FR 20036, 20051 (April 6, 2022); 86 FR 23054, 23062 (April 30, 2021); 81 FR 74504, 74506 (Oct. 26, 2016). In the FIP proposal, as in prior transport actions, the EPA discussed a number of ways in which states could take over or replace a FIP, *see* 87 FR 20036, 20149–51 (section VII.D: ''Submitting A SIP''); *see also id.* at 20040 (noting as one purpose in proposing the FIP that ''this proposal will provide states with as much information as the EPA can supply at this time to support their ability to submit SIP revisions to achieve the emissions reductions the EPA believes necessary to eliminate significant contribution''). The EPA provides further guidance on submitting SIPs in this section. If, and when, the EPA receives a SIP submission that satisfies the requirements of CAA section 110(a)(2)(D)(i)(I) and 110(l), the Agency will take action to approve those SIP submissions and withdraw the FIP.

At the outset, we note that the Agency does not anticipate revisiting its findings at Steps 1 or 2 of the transport framework. Those findings establish that the projected baseline anthropogenic emissions from these states contribute to downwind nonattainment or maintenance receptors in 2023, and, for certain states, that contribution continues through 2026. Those represent critical analytical years for downwind areas as they are the last full ozone season before the Moderate and Serious area attainment dates. Those findings, for those years, establish the basis for an upwind state's linkage, from which we proceed to evaluate emissions control opportunities and their implementation at Steps 3 and 4.

We cannot prejudge now whether state submissions to replace the EPA's FIP will be approvable, but we note a number of statutory and implementation considerations states should be aware of if designing a replacement SIP. We have demonstrated that the EPA's transport FIP is adequate to eliminate significant contribution to downwind air quality problems for purposes of the 2015 ozone NAAQS, and that the FIP does not result in overcontrol. The level of reductions required by the FIP therefore provides an important benchmark for states in evaluating the equivalency of possible replacement SIPs. As discussed in more detail in this section, in order to comply with their obligation under CAA section 110(a)(2)(D)(i)(I), we generally anticipate that states seeking to replace the FIP with a SIP that takes an alternative approach would need to establish, at a minimum, an equivalent level of emissions reduction to what the FIP requires at Step 3, and any such replacement SIP will need to comply with CAA section 110(*l*).

The concept of equivalency is important for the state to consider. Under CAA section 110(l), ''the Administrator shall not approve a revision of a plan if the revision would interfere with any applicable requirement concerning attainment . . . or any other applicable requirement of this chapter.'' Section 110(l) applies to all CAA requirements, including 110(a)(2)(D) requirements relating to interstate transport. The EPA interprets section 110(l) such that states have two main options to make a noninterference demonstration. First, the state could demonstrate that emissions reductions removed from the SIP are replaced with new control measures that achieve equivalent or greater emissions reductions. Thus, a 110(l) analysis would generally need to show that the SIP revision, or, in this case, a potential SIP submission replacing an existing FIP, will not interfere with any area's ability to continue to attain or maintain the affected NAAQS or other CAA requirements. The EPA further has interpreted section 110(l) as requiring such substitute measures to be quantifiable, permanent, and enforceable, among other considerations. For section 110(l) purposes, ''permanent'' means the state cannot modify or remove the substitute measure without EPA review and approval. Second, the state could conduct air quality modeling or develop an attainment or maintenance demonstration based on the EPA's most recent technical guidance to show that, even without the control measure or with the control measure in its modified form, significant contribution from the state would continue to be prohibited as the Act requires. As discussed further in this section, for purposes of interstate ozone transport, such an analysis entails important questions of consistency and equity among states for resolving air quality problems that the EPA would need to carefully evaluate.[405]

[405] For instance, future circumstances in which the receptor or receptors to which a state is linked come fully into attainment or to which the upwind state's linkage drops below 1 percent of the NAAQS would likely not, solely on those grounds, be sufficient to relax transport requirements established by the FIP or justify approving a less stringent SIP. First, the emissions reductions achieved by the FIP are part of the reason that a receptor may come into attainment or a linkage may drop below 1 percent of the NAAQS. Simply

Continued

In the EPA's experience implementing the CAA criteria pollutant program, reductions arising from the good neighbor provision have been critically important to the improvement of air quality in downwind areas struggling with attainment and maintenance of the NAAQS, and states' reliance on good neighbor FIP reductions will need to be taken into account in any replacement SIP. In order for a nonattainment area to be redesignated to attainment, the CAA requires not only that an area attain the standard, but also the Administrator must determine ''that the improvement in air quality is due to permanent and enforceable reductions in emissions resulting from implementation of the applicable implementation plan and applicable Federal air pollutant control regulations and other permanent and enforceable reductions.'' CAA section 107(d)(3)(E)(i) and (iii). Many nonattainment areas across the country that have attained various $PM_{2.5}$ and ozone NAAQS have done so in part due to the imposition of Federal good neighbor emissions control measures, and, per CAA section 107(d)(3)(E)(iii), states have specifically relied on the emissions reductions required by those programs in order to be redesignated to attainment. *See, e.g.,* 84 FR 8422, 8425 (March 8, 2019) (noting that ''[a]t least 140 EPA final actions redesignating areas in 20 states to attainment with an ozone NAAQS or a fine particulate matter ($PM_{2.5}$) NAAQS—because NO_X is a precursor to $PM_{2.5}$ as well as ozone—have relied in part on the NO_X SIP Call's emissions reductions''); *see also Sierra Club* v. *EPA,* 774 F.3d 383, 397–99 (7th Cir. 2014) (upholding EPA's approval of a redesignation, and specifically EPA's determination that reductions from Federal good neighbor transport trading programs could reasonably be considered ''permanent and enforceable'' under the statute); *Sierra Club* v. *EPA,* 793 F.3d 656, 665–68 (6th Cir. 2015) (same). States seeking area redesignations are also required under CAA section 107(d)(3)(E)(iv) to develop revisions to their state implementation plans that provide for maintenance of the NAAQS. In so doing, states develop air quality modeling, in which they project future air quality based on emissions inputs that account for enforceable emissions reductions, or states project emissions in the future relative to emissions in an attainment year, showing that the future emissions (which, again, account for on-the-books, enforceable emissions limits) do not exceed emissions in the baseline attainment year. *See* ''Procedures for Processing Requests to Redesignate Areas to Attainment,'' Memo from John Calcagni to EPA Regions, September 4, 1992, at 9. Reductions required by Federal good neighbor programs may therefore also be relied upon by states seeking area redesignations in the context of how states demonstrate that areas will maintain the NAAQS.

We anticipate that air quality in areas struggling to attain and maintain the 2015 ozone NAAQS will improve due to the emissions reductions required by EPA's FIP. We also anticipate that, consistent with EPA's historical experience implementing the NAAQS and acting on state requests for nonattainment area redesignations, emissions reductions associated with EPA's transport FIP for the 2015 ozone NAAQS are likely to be a critical component in those requests for redesignation. Where states have relied and are relying on the FIP's reductions in order to attain and maintain the NAAQS, EPA will look very critically at any replacement SIP that appears to fall short of equivalent emissions reductions—in terms of the level of reductions or the permanence of those reductions.

Finally, we disagree with commenters that the absence of fixed, mass-based emissions budgets for each state make it impossible to replace the FIP with an equivalent SIP. In the case of the trading program enhancements for EGUs, the EPA recognizes that the dynamic budgeting methodology will generally function to impose a continuous incentive on relevant EGUs to continue to implement the emissions control strategies determined at Step 3. Further, the backstop rate and banking recalibration enhancements also are designed to ensure that EGUs implement emissions controls consistent with Step 3 determinations on a continuous basis throughout each ozone season. As explained in section V.D.4 of this document, these aspects of the trading program do not in themselves introduce an overcontrol concern. Nonetheless, consistent with the more general principles discussed in this section with respect to the potential bases on which states may replace the FIP with SIPs, we reserve judgment at this time on whether some future demonstration could successfully establish that revision of the FIP or its replacement with a SIP could be acceptable even if the way that significant contribution is eliminated is through means that differ from the trading program enhancements included for EGUs in this action. As discussed further in this section, a state may choose to withdraw its EGUs from the trading program and instead subject those EGUs to daily emissions rates commensurate with installation and optimization of state-of-the-art combustion and post-combustion controls as the EPA determined at Step 3. Likewise, states are free to explore an alternative set of emissions controls on non-EGU industrial sources (or other sources in the state), so long as they can demonstrate that an equivalent amount of emissions is eliminated. In any case, we need not resolve these questions here. The EPA, in promulgating a FIP, is not obligated to identify each way a state could replace it with a SIP revision. Several options are discussed further in this section, and, as always, EPA Regional Offices will work closely with states who wish to explore these options or other alternatives.

1. SIP Option To Modify Allocations for 2024 Under EGU Trading Program

As with the start of past CSAPR rulemakings, the EPA is finalizing the option to allow a state to use a similar process to submit a SIP revision establishing allowance allocations for existing EGU units in the state for the second control period of the new requirements, *i.e.,* in 2024, to replace the EPA-determined default allocations. A state must submit a letter to EPA by August 4, 2023, indicating its intent to submit a complete SIP revision by September 1, 2023. The SIP would provide in an EPA-prescribed format a list of existing units within the state and their allocations for the 2024 control period. If a state does not submit a letter of intent to submit a SIP revision, the EPA-determined default allocations will be recorded by September 5, 2023. If a state submits a timely letter of intent but fails to submit a SIP revision, the EPA-determined default allocations will be recorded by September 15, 2023. If a state submits a timely letter of intent

removing emissions control requirements the moment this occurs is illogical, since those reductions are part of the solution by which the attaining air quality was achieved or the linkage was resolved. *See* CAA section 107(d)(3)(E)(iii) (areas cannot be redesignated unless based on permanent and enforceable reductions); *see also Wisconsin,* 938 F.3d at 324–25 (explaining that upwind states are held to a contribution standard, not a but-for causation standard and thus cannot escape good neighbor obligations on the basis that other emissions ''cause'' the NAAQS to be exceeded). There is a risk of inconsistency and inequity in removing any requirements in this manner in that any increase in emissions that could occur in one upwind state would likely need to be reviewed in relation to the obligations other upwind states would continue to meet. Further, any such relaxation in upwind state requirements could then unreasonably shift the burden for maintaining air quality onto the downwind states where receptors are located. These issues may entail complex state- or case-specific analyses that would need to be evaluated at the time such a SIP revision is submitted; these issues are not ripe for resolution in this action.

followed by a timely SIP revision that is approved, the approved SIP allocations will be recorded by March 1, 2024.

The EPA received no comments on the proposed option to modify allowance allocations under the Group 3 trading program for EGUs for the 2024 control period through a SIP revision and is finalizing the provisions as proposed.

2. SIP Option To Modify Allocations for 2025 and Beyond Under EGU Trading Program

For the 2025 control period and later, states in the CSAPR NO_X Ozone Season Group 3 Trading Program can modify the EPA-determined default allocations with an approved SIP revision. For the 2025 control period and later, SIPs can be full or abbreviated SIPs. *See* 76 FR 48326–48332 for additional discussion of full and abbreviated SIP options; *see also* 40 CFR 52.38(b).

In this final rule, the EPA is removing the previous regulatory text defining specific options for states to expand CSAPR NO_X Ozone Season Group 3 trading program applicability to include EGUs between 15 MWe and 25 MWe or, in the case of states subject to the NO_X SIP Call, large non-EGU boilers and combustion turbines. These options for expanding trading program applicability through SIP revisions have been available to states since the start of the CSAPR trading programs for small EGUs and since the CSAPR Update for large non-EGU boilers and combustion turbines, and no state has chosen to use the SIP process for this purpose. Additionally, the EPA did not receive comment supporting these expansion options during the comment period for this rule. The EPA is finalizing a methodology for updating the affected EGU portion of the budget in this rule, and the regulatory text defining the applicability expansion to non-EGUs did not include a mechanism for updating the incremental non-EGU portion of a state's budget based on changes over time of the non-EGU fleet; therefore, continuation of the option to expand applicability to certain non-EGUs subject to the NO_X SIP Call would be inconsistent with the trading program as applied to EGUs in this rule.

However, the EPA recognizes that states may seek to include non-EGUs covered in this action in an emissions trading program, subject to important considerations to ensure equivalency in emissions reductions is maintained. While the EPA is not offering specific regulatory text to implement an option to expand the trading program applicability, a state could submit a SIP to expand the CSAPR NO_X Ozone Season Group 3 Trading Program applicability, which the EPA would evaluate on a case-by-case basis. The SIP revision would need to address critical program elements, and include: (1) high-quality baseline data, (2) ongoing Part 75 monitoring, and (3) provisions to update the non-EGU portion of the budget to appropriately reflect changes to the fleet over time.

For states that want to modify the EPA-determined default allocations, the EPA proposed that a state could submit a SIP revision that makes changes only to that provision while relying on the FIP for the remaining provisions of the EGU trading program. This abbreviated SIP option allows states to tailor the FIP to their individual choices while maintaining the FIP-based structure of the trading program. To ensure the availability of allowance allocations for units in any Indian country within a state not covered by the state's CAA implementation planning authority, if the state chose to replace the EPA's default allocations with state-determined allocations, the EPA would continue to administer any portion of each state emissions budget reserved as a new unit set-aside or an Indian country existing unit set-aside.

The SIP submittal deadline for this type of revision is December 1, 2023, if the state intends for the SIP revision to be effective beginning with the 2025 control period. For states that submit this type of SIP revision, the deadline to submit state-determined allocations beginning with the 2025 control period under an approved SIP is June 1, 2024, and the deadline for the EPA to record those allocations is July 1, 2024. Similarly, a state can submit a SIP revision beginning with the 2026 control period and beyond by December 1, 2024, with state allocations for the 2026 control period due June 1, 2025, and EPA recordation of the allocations by July 1, 2025.

The EPA received no comment on the option to replace certain allowance allocation provisions under the Group 3 trading program for EGUs for control periods in 2025 and later years through a SIP revision and is finalizing the provisions generally as proposed, with the exception that any potential expansion of trading program applicability under a SIP revision would be evaluated on a case-by-case basis.

3. SIP Option To Replace the Federal EGU Trading Program With an Integrated State EGU Trading Program

For the 2025 control period and later, states in the CSAPR NO_X Ozone Season Group 3 Trading Program can choose to replace the Federal EGU trading program with an integrated State EGU trading program through an approved SIP revision. Under this option, a state can submit a SIP revision that makes changes only to modify the EPA-determined default allocations and that adopts identical provisions for the remaining portions of the EGU trading program. This SIP option allows states to replace these FIP provisions with state-based SIP provisions while continuing participation in the larger regional trading program. As with the abbreviated SIP option discussed previously, to ensure the availability of allowance allocations for units in any Indian country within a state not covered by the state's CAA implementation planning authority, if the state chooses to replace the EPA's default allocations with state-determined allocations, the EPA would continue to administer any portion of each state emissions budget reserved as a new unit set-aside or an Indian country existing unit set-aside. Also, for the same reasons discussed with respect to the abbreviated SIP option, the EPA is removing the option for states to expand CSAPR NO_X Ozone Season Group 3 trading program applicability to include EGUs between 15 MWe and 25 MWe or, in the case of states subject to the NO_X SIP Call, large non-EGU boilers and combustion turbines.

Deadlines for this type of SIP revision are the same as the deadlines for abbreviated SIP revisions. For the SIP-based program to start with the 2025 control period, the SIP deadline is December 1, 2023, the deadline to submit state-determined allocations for the 2025 control period under an approved SIP is June 1, 2024, and the deadline for the EPA to record those allocations is July 1, 2024, and so on.

The EPA received no comment on the option to replace the Federal trading program for EGUs with an integrated state trading program for EGUs for control periods in 2025 and later years through a SIP revision and is finalizing the provisions generally as proposed, with the exception that any potential expansion of trading program applicability under a SIP revision would be evaluated on a case-by-case basis.

4. SIP Revisions That Do Not Use the Trading Program

States can submit SIP revisions to replace the FIP that achieve the necessary EGU emissions reductions but do not use the CSAPR NO_X Ozone Season Group 3 Trading Program. For a transport SIP revision that does not use the CSAPR NO_X Ozone Season Group 3 Trading Program, the EPA would evaluate the transport SIP based on the particular control strategies selected and whether the strategies as a whole provide adequate and enforceable provisions ensuring that the necessary emissions reductions (*i.e.,* reductions equal to or greater than what the Group 3 trading program will achieve) will be achieved. To address the applicable CAA requirements, the SIP revision should include the following general elements: (1) a comprehensive baseline 2023 statewide NO_X emissions inventory (which includes existing control requirements), which should be consistent with the 2023 emissions inventory that the EPA used to calculate the required state budget in this final rule (unless the state can explain the discrepancy); (2) a list and description of control measures to satisfy the state emissions reduction obligation and a demonstration showing when each measure would be implemented to meet the 2023 and successive control periods; (3) fully-adopted state rules providing for such NO_X controls during the ozone season; (4) for EGUs greater than 25 MWe, monitoring and reporting under 40 CFR part 75, and for other units, monitoring and reporting procedures sufficient to demonstrate that sources are complying with the SIP (*see* 40 CFR part 51, subpart K (''source surveillance'' requirements)); and (5) a projected inventory demonstrating that state measures along with Federal measures will achieve the necessary emissions reductions in time to meet the 2023 and successive compliance deadlines (*e.g.,* enforceable reductions commensurate with installation of SCR on coal-fired EGUs by the 2027 ozone season). The SIPs must meet procedural requirements under the Act, such as the requirements for public hearing, be adopted by the appropriate state board or authority, and establish by a practically enforceable regulation or permit(s) a schedule and date for each affected source or source category to achieve compliance. Once the state has made a SIP submission, the EPA will evaluate the submission(s) for completeness before acting on the SIP. EPA's criteria for determining completeness of a SIP submission are codified at 40 CFR part 51, appendix V.

For further background information on considerations for replacing a FIP with a SIP, *see* the discussion in the final CSAPR rulemaking (76 FR 48326).

5. SIP Revision Requirements for Non-EGU or Industrial Source Control Requirements

EPA's promulgation of a non-EGU transport FIP would in no way affect the ability of states to submit, for review and approval, a SIP that replaces the requirements of the FIP with state requirements. To replace the non-EGU portion of the FIP in a state, the state's SIP must provide adequate provisions to prohibit NO_X emissions that contribute significantly to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in any other state. The state SIP submittal must demonstrate that the emissions reductions required by the SIP would continue to ensure that significant contribution from that state has been eliminated through permanent and enforceable measures. The non-EGU requirements of the FIP would remain in place in each covered state until a state's SIP has been approved by the EPA to replace the FIP.

The most straightforward method for a state to submit a presumptively approvable SIP revision to replace the non-EGU portion of the FIPs for the state would be to provide a SIP that includes emissions limits at an equivalent or greater level of stringency than is specified for non-EGU sources meeting the applicability criteria and associated compliance assurance provisions for each of the unit types identified in section VI.C of this document.

Comment: One commenter stated that they believed EPA's assertion in the proposal that any SIP submittal would have to achieve equal or greater reductions for non-EGUs than the FIP was unlawful. The commenter asserted that a state's ability to replace the FIP must be tied to whether it has addressed the underlying nonattainment/maintenance concerns by reducing significant contribution from sources in the state below the significance threshold, (as opposed to whether it prohibits equivalent emissions to the FIP).

Response: The EPA recognizes that states may select emissions reductions strategies that differ from the emissions limitations included in the proposed non-EGU FIP; this is discussed in response to comments earlier in this section. For example, some states may desire to include non-EGUs in a trading program. This may be possible subject to taking into account a number of considerations as discussed earlier in this section to ensure equivalency between the different approaches. But the state must still demonstrate that the replacement SIP provides an equivalent or greater amount of emissions reductions as the proposed FIP to be presumptively approvable. The EPA anticipates that such emissions reductions strategies would have to achieve reductions equivalent to or beyond those emissions reductions already projected to occur in EPA's emissions projections and air quality modeling conducted at Steps 1 and 2. Such reductions must also be achieved by the 2026 ozone season.

EPA further acknowledges that a demonstration of equivalency using other control strategies is complicated by the fact that the final emissions limits for non-EGU sources are generally unit-specific and expressed in a variety of forms; comparative analysis with alternative control requirements to determine equivalency would need to take this into account. Similarly, we recognize that the emissions trading program for EGUs in this action includes a number of enhancements to ensure that the Step 3 determination of which emissions are ''significant'' and must be eliminated continues to be implemented over time. Although there is not a fixed, mass-based emissions budget established for each state in this action, there are other objective metrics that could guide states in developing replacement SIPs. For example, for non-EGUs, states may choose to conduct an analysis of their industrial stationary sources and present an alternative set of emissions limits applying to specific units that it believes would achieve an equivalent level of emissions reduction. States could apply cost-effectiveness thresholds for emissions control technologies that could be applied to establish that some alternative emissions control strategy results in equivalent or greater improvement at downwind receptors. The EPA anticipates that such a comparison may entail review of both baseline emissions information and growth projections between the different sets of units to ensure that a truly equivalent or greater degree of emissions reduction is achieved; additionality and emissions shifting potential may also need to be considered. We note that the CAMx policy case run for 2026 provides a benchmark for assessing the level of air quality improvement anticipated at receptors with implementation of the FIP. This data may be of use to states as part of a demonstration that a replacement SIP achieves an equivalent or greater level of air quality improvement to the FIP; however, the use of such modeling in such a demonstration would need to be more fully evaluated at the time of such a SIP revision.

In all cases, a SIP submitted by a state to replace the non-EGU components of the FIPs would very likely need to rely on permanent and practically enforceable controls measures that are included in the SIP and, once approved by the EPA, rendered federally enforceable. So-called ''demonstration-only'' or ''non-regulatory'' SIPs would very likely be insufficient; see discussion in response to comments earlier in this section. Further, the EPA anticipates that states would bear the burden of establishing that the state's alternative approach achieves at least an equivalent level of emissions reduction as the FIP.

E. Title V Permitting

This final rule, like CSAPR, the CSAPR Update, and the Revised CSAPR Update does not establish any permitting requirements independent of those under Title V of the CAA and the regulations implementing Title V, 40 CFR parts 70 and 71.[406] All major stationary sources of air pollution and certain other sources are required to apply for title V operating permits that include emissions limitations and other conditions as necessary to ensure compliance with the applicable requirements of the CAA, including the requirements of the applicable SIP. CAA sections 502(a) and 504(a), 42 U.S.C. 7661a(a) and 7661c(a). The ''applicable requirements'' that must be addressed in title V permits are defined in the title V regulations (40 CFR 70.2 and 71.2 (definition of ''applicable requirement'')).

The EPA anticipates that, given the nature of the units subject to this final rule, most if not all of the sources at which the units are located are already subject to title V permitting requirements and already possess a title V operating permit. For sources subject to title V, the interstate transport requirements for the 2015 ozone NAAQS that are applicable to them under the FIPs finalized in this action would be ''applicable requirements'' under title V and therefore must be addressed in the title V permits. For example, EGU requirements concerning designated representatives, monitoring, reporting, and recordkeeping, the requirement to hold allowances covering emissions, the compliance assurance provisions, and liability, and for non-EGUs, the emissions limits and compliance requirements are, to the extent relevant to each source, ''applicable requirements'' that must be addressed in the permits.

Consistent with EPA's approach under CSAPR, the CSAPR Update and the Revised CSAPR Update, the applicable requirements resulting from the FIPs generally will have to be incorporated into affected sources' existing title V permits either pursuant to the provisions for reopening for cause (40 CFR 70.7(f) and 71.7(f)), significant modifications (40 CFR 70.7(e)(4)) or the standard permit renewal provisions (40 CFR 70.7(c) and 71.7(c)).[407] For sources newly subject to title V that are affected sources under the FIPs, the initial title V permit issued pursuant to 40 CFR 70.7(a) should address the final FIP requirements.

As was the case in the CSAPR, the CSAPR Update and the Revised CSAPR Update, the new and amended FIPs impose no independent permitting requirements and the title V permitting process will impose no additional burden on sources already required to be permitted under title V.

1. Title V Permitting Considerations for EGUs

Title V of the CAA establishes the basic requirements for state title V permitting programs, including, among other things, provisions governing permit applications, permit content, and permit revisions that address applicable requirements under final FIPs in a manner that provides the flexibility necessary to implement market-based programs such as the trading programs established in CSAPR, the CSAPR Update, the Revised CSAPR Update and this final rule. 42 U.S.C. 7661a(b); 40 CFR 70.6(a)(8) & (10); 40 CFR 71.6(a)(8) & (10).

In CSAPR, the CSAPR Update and the Revised CSAPR Update, the EPA established standard requirements governing how sources covered by those rules would comply with title V and its regulations.[408] 40 CFR 97.506(d), 97.806(d) and 97.1006(d). For any new or existing sources subject to this rule, identical title V compliance provisions will apply with respect to the CSAPR NO_X Ozone Season Group 3 Trading Program. For example, the title V regulations provide that a permit issued under title V must include ''[a] provision stating that no permit revision shall be required under any approved . . . emissions trading and other similar programs or processes for changes that are provided for in the permit.'' 40 CFR 70.6(a)(8) and 71.6(a)(8). Consistent with these provisions in the title V regulations, in CSAPR, the CSAPR Update and the Revised CSAPR Update, the EPA included a provision stating that no permit revision is necessary for the allocation, holding, deduction, or transfer of allowances. 40 CFR 97.506(d)(1), 97.806(d)(1) and 97.1006(d)(1). This provision is also included in each title V permit for an affected source. This final rule maintains the approach taken under CSAPR, the CSAPR Update and the Revised CSAPR Update that allows allowances to be traded (or allocated, held, or deducted) without a revision to the title V permit of any of the sources involved.

Similarly, this final rule would also continue to support the means by which a source in the final trading program can use the title V minor modification procedure to change its approach for monitoring and reporting emissions, in certain circumstances. Specifically, sources may use the minor modification procedure so long as the new monitoring and reporting approach is one of the prior-approved approaches under CSAPR, the CSAPR Update and the Revised CSAPR Update (*i.e.,* approaches using a continuous emissions monitoring system under subparts B and H of 40 CFR part 75, an excepted monitoring system under appendices D and E to 40 CFR part 75, a low mass emissions excepted monitoring methodology under 40 CFR 75.19, or an alternative monitoring system under subpart E of 40 CFR part 75), and the permit already includes a description of the new monitoring and reporting approach to be used. *See* 40 CFR 97.506(d)(2), 97.806(d)(2) and 97.1006(d)(2); 40 CFR 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B). As described in EPA's 2015 Title V Guidance, sources may comply with this requirement by including a table of all of the approved monitoring and reporting approaches under CSAPR, the CSAPR Update and the Revised CSAPR Update trading programs in which the source is required to participate, and the applicable requirements governing each of those approaches.[409] Inclusion of such a table in a source's title V permit therefore allows a covered unit that seeks to change or add to its chosen monitoring and recordkeeping approach to easily comply with the regulations

[406] Part 70 addresses requirements for state title V programs, and part 71 governs the Federal title V program.

[407] A permit is reopened for cause if any new applicable requirements (such as those under a FIP) become applicable to an affected source with a remaining permit term of 3 or more years. If the remaining permit term is less than 3 years, such new applicable requirements will be added to the permit during permit renewal. *See* 40 CFR 70.7(f)(1)(i) and 71.7(f)(1)(i).

[408] The EPA has also issued a guidance document and template that includes instructions for how to incorporate the applicable requirements into a source's Title V permit. *See* Memorandum dated May 13, 2015, from Anna Marie Wood, Director, Air Quality Policy Division, and Reid P. Harvey, Director, Clean Air Market Division, EPA, to Regional Air Division Directors, Subject: ''Title V Permit Guidance and Template for the Cross-State Air Pollution Rule'' (''2015 Title V Guidance''), available at *https://www.epa.gov/sites/default/files/2016–10/documents/csapr_title_v_permit_guidance.pdf.*

[409] *Id.*

governing the use of the title V minor modification procedure.

Under CSAPR, the CSAPR Update and the Revised CSAPR Update, to employ a monitoring or reporting approach different from the prior-approved approaches discussed previously, unit owners and operators must submit monitoring system certification applications to the EPA establishing the monitoring and reporting approach actually to be used by the unit, or, if the owners and operators choose to employ an alternative monitoring system, to submit petitions for that alternative to the EPA. These applications and petitions are subject to the EPA review and approval to ensure consistency in monitoring and reporting among all trading program participants. EPA's responses to any petitions for alternative monitoring systems or for alternatives to specific monitoring or reporting requirements are posted on EPA's website.[410] The EPA maintains the same approach for the trading program in this final rule.

2. Title V Permitting Considerations for Industrial Stationary Sources

For non-EGU sources, affected sources will need to work with their local, state, or tribal permitting authority to determine if the new applicable requirements should be incorporated into their existing title V permit under the reopening for cause, significant modification, or permit renewal procedures of the approved permitting program. Title V permits for existing sources will need to be updated to include the applicable requirements of this final rule and any necessary preconstruction permits obtained in order to comply with this final rule.

F. Relationship to Other Emissions Trading and Ozone Transport Programs

1. NO_X SIP Call

Sources in states affected by both the NO_X SIP Call for the 1979 ozone NAAQS and the requirements established in this final rule for the 2015 ozone NAAQS will be required to comply with the requirements of both rules. With respect to EGUs larger than 25 MW, in this rule the EPA is requiring NO_X ozone season emissions reductions from these sources in many of the NO_X SIP Call states, and at greater stringency than required by the NO_X SIP Call, by requiring the EGUs to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program. The emissions reductions required under this rule are therefore sufficient to satisfy the emissions reduction requirements under the NO_X SIP Call for these large EGUs.

With respect to the large non-EGU boilers and combustion turbines that formerly participated in the NO_X Budget Trading Program under the NO_X SIP Call, the EPA provided options under both the CSAPR Update and the Revised CSAPR Update for states to address these sources' ongoing NO_X SIP Call requirements by expanding applicability of the relevant CSAPR trading programs for ozone season NO_X emissions to include the sources, and no state chose to use these options. As discussed in sections VI.D.2 and VI.D.3, in this rule the EPA is removing the previous regulatory text defining specific options for states to expand trading program applicability to include these sources and instead will evaluate any SIP revisions seeking to include these sources in the Group 3 trading program on a case-by-case basis.[411]

2. Acid Rain Program

This rule does not affect any SO_2 and NO_X requirements under the Acid Rain Program, which are established separately under 40 CFR parts 72 through 78 and will continue to apply independently of this rule's provisions. Sources subject to the Acid Rain Program will continue to be required to comply with all requirements of that program, including the requirement to hold sufficient allowances issued under the Acid Rain Program to cover their SO_2 emissions after the end of each control period.

3. Other CSAPR Trading Programs

This rule does not substantively affect any provisions of the CSAPR NO_X Annual, CSAPR SO_2 Group 1, CSAPR SO_2 Group 2, CSAPR NO_X Ozone Season Group 1, or CSAPR NO_X Ozone Season Group 2 trading programs for sources that continue to participate in those programs. Sources subject to any of the CSAPR trading programs will continue to be required to comply with all requirements of all such trading programs to which they are subject, including the requirement to hold sufficient allowances issued under the respective programs to cover emissions after the end of each control period.

The EPA also notes that where a state's good neighbor obligations with respect to the 1997 ozone NAAQS or the 2008 ozone NAAQS have previously been met by participation of the state's large EGUs in the CSAPR NO_X Ozone Season Group 2 Trading Program (or earlier by the CSAPR NO_X Ozone Season Group 1 Trading Program), the EPA will deem those obligations to be satisfied by the participation of the same sources in the CSAPR NO_X Ozone Season Group 3 Trading Program. Specifically, for all states covered by the Group 3 trading program under this rule except Minnesota, Nevada, and Utah, participation of the state's EGUs in the Group 3 trading program will be deemed to satisfy not only the EGU-related portion of the state's good neighbor obligations with respect to the 2015 ozone NAAQS but also the state's good neighbor obligations with respect to the 2008 ozone NAAQS. In addition, for Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Michigan, Mississippi, Missouri, Oklahoma, and Wisconsin, participation of the state's EGUs in the Group 3 trading program will also be deemed to satisfy the state's good neighbor obligations with respect to the 1997 ozone NAAQS.[412]

VII. Environmental Justice Analytical Considerations and Stakeholder Outreach and Engagement

Consistent with EPA's commitment to integrating environmental justice in the agency's actions, and following the directives set forth in multiple Executive orders, the Agency has analyzed the impacts of this final rule on communities with environmental justice concerns and engaged with stakeholders representing these communities to seek input and feedback. Executive Order 12898 is discussed in section X.J of this final rule and analytical results are available in Chapter 7 of the *RIA.* This analysis is being provided for informational purposes only.

A. Introduction

Executive Order 12898 directs EPA to identify the populations of concern who are most likely to experience unequal burdens from environmental harms; specifically, minority populations, low-income populations, and indigenous peoples.[413] Additionally, Executive

[410] *https://www.epa.gov/airmarkets/part-75-petition-responses.*

[411] Only one NO_X SIP Call state—Tennessee—continues to participate in the Group 2 trading program, and the EPA has already approved other SIP provisions addressing the ongoing NO_X SIP Call obligations for Tennessee's large non-EGU boilers and combustion turbines. *See* 84 FR 7998 (March 6, 2019); 86 FR 12092 (March 2, 2021).

[412] For the remaining state transitioning from the Group 2 trading program to the Group 3 trading program under this rule—Texas—as well as the remaining states that transitioned from the Group 2 trading program to the Group 3 trading program under the Revised CSAPR Update—Maryland, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia—participation of the states' EGUs in the Group 2 trading program as required by the CSAPR Update was addressing good neighbor obligations of the states with respect to only the 2008 ozone NAAQS, not the 1997 ozone NAAQS. *See* 81 FR 74523–74526.

[413] 59 FR 7629, February 16, 1994.

Order 13985 is intended to advance racial equity and support underserved communities through Federal Government actions.[414] The EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA further defines the term fair treatment to mean that ''no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies.'' [415] In recognizing that minority and low-income populations often bear an unequal burden of environmental harms and risks, the EPA continues to consider ways of protecting them from adverse public health and environmental effects of air pollution.

B. Analytical Considerations

The EPA's environmental justice (EJ) technical guidance [416] states that:

> The analysis of potential EJ concerns for regulatory actions should address three questions:
>
> 1. Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline?
>
> 2. Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration?
>
> 3. For the regulatory option(s) under consideration, are potential EJ concerns created or mitigated compared to the baseline?

To address these questions in the EPA's first quantitative EJ analysis in the context of a transport rule, the EPA developed a unique analytical approach that considers the purpose and specifics of the final rulemaking, as well as the nature of known and potential exposures and impacts. However, due to data limitations, it is possible that our analysis failed to identify disparities that may exist, such as potential environmental justice characteristics (*e.g.,* residence of historically red lined areas), environmental impacts (*e.g.,* other ozone metrics), and more granular spatial resolutions (*e.g.,* neighborhood scale) that were not evaluated.

For the final rule, we employ two types of analytics to respond to the previous three questions: proximity analyses and exposure analyses. Both types of analyses can inform whether there are potential EJ concerns for population groups of concern in the baseline (question 1).[417] In contrast, only the exposure analyses, which are based on future air quality modeling, can inform whether there will be potential EJ concerns after implementation of the regulatory options under consideration (question 2) and whether potential EJ concerns will be created or mitigated compared to the baseline (question 3). While the exposure analysis can respond to all three questions, several caveats should be noted. For example, the air pollutant exposure metrics are limited to those used in the benefits assessment. For ozone, that is the maximum daily 8-hour average, averaged across the April through September warm season (AS–MO3) and for $PM_{2.5}$ that is the annual average. This ozone metric likely smooths potential daily ozone gradients and is not directly relatable to the National Ambient Air Quality Standard (NAAQS), whereas the $PM_{2.5}$ metric is more similar to the long term $PM_{2.5}$ standard. The air quality modeling estimates are also based on state level emissions data paired with facility-level baseline emissions, and provided at a resolution of $12km^2$. Additionally, here we focus on air quality changes due to this final rulemaking and infer post-policy exposure burden impacts.

Exposure analytic results are provided in two formats: aggregated and distributional. The aggregated results provide an overview of potential ozone exposure differences across populations at the national- and state-levels, while the distributional results show detailed information about ozone concentration changes experienced by everyone within each population.

In Chapter 7 of the *RIA* we utilize the two types of analytics to address the three EJ questions by quantitatively evaluating: (1) the proximity of affected facilities to potentially disadvantaged populations (section 7.3); and (2) the potential for disproportionate ozone and $PM_{2.5}$ concentrations in the baseline and concentration changes after rule implementation across different demographic groups (section 7.4). Each of these analyses depends on mutually exclusive assumptions, was performed to answer separate questions, and is associated with unique limitations and uncertainties.

Baseline demographic proximity analyses can be relevant for identifying populations that may be exposed to local pollutants, such as NO_2 emitted from affected sources in this final rule. However, such analyses are less useful here as they do not account for the potential impacts of this final rule on long-range concentration changes. Baseline demographic proximity analysis presented in the *RIA* suggest that larger percentages of Hispanics, African Americans, people below the poverty level, people with less educational attainment, and people linguistically isolated are living within 5 km and 10 km of an affected EGU, compared to national averages. It also finds larger percentages of African Americans, people below the poverty level, and with less educational attainment living within 5 km and 10 km of an affected non-EGU facility. Relating these results to question 1 from section 7.2 of the *RIA,* we conclude that there may be potential EJ concerns associated with directly emitted pollutants that are affected by the regulatory action (*e.g.,* NO_2) for certain population groups of concern in the baseline. However, as proximity to affected facilities does not capture variation in baseline exposure across communities, nor does it indicate that any exposures or impacts will occur, these results do not in themselves demonstrate disproportionate impacts of affected facilities in the baseline and should not be interpreted as a direct measure of exposure or impact.

Whereas proximity analyses are limited to evaluating the representativeness of populations residing nearby affected facilities, the ozone and $PM_{2.5}$ exposure analyses can provide insight into all three EJ questions. Even though both the proximity and exposure analyses can potentially improve understanding of baseline EJ concerns (question 1), the two should not be directly compared. This is because the demographic proximity analysis does not include air quality information and is based on current, not future, population information.

The baseline analysis of ozone and $PM_{2.5}$ concentration burden responds to question 1 from EPA's environmental justice technical guidance document more directly than the proximity analyses, as it evaluates a form of the environmental stressor targeted by the regulatory action. Baseline ozone and $PM_{2.5}$ analyses show that certain populations, such as Hispanics, Asians, those linguistically isolated, those less

[414] 86 FR 7009, January 20, 2021.

[415] *https://www.epa.gov/environmentaljustice.*

[416] U.S. Environmental Protection Agency (EPA), 2015. Guidance on Considering Environmental Justice During the Development of Regulatory Actions.

[417] The baseline for proximity analyses is current population information (*e.g.,* 2021), whereas the baseline for ozone exposure analyses are the future years in which the regulatory options will be implemented (*e.g.,* 2023 and 2026).

educated, and children may experience somewhat higher ozone and $PM_{2.5}$ concentrations compared to the national average. Therefore, also in response to question 1, there likely are potential environmental justice concerns associated with ozone and $PM_{2.5}$ exposures affected by the regulatory action for population groups of concern in the baseline. However, these baseline exposure results have not been fully explored and additional analyses are likely needed to understand potential implications. In addition, we infer that disparities in the ozone and $PM_{2.5}$ concentration burdens are likely to persist after implementation of the regulatory action or alternatives under consideration due to similar modeled concentration reductions across population demographics (question 2).

Question 3 asks whether potential EJ concerns will be created or mitigated as compared to the baseline. Due to the very small differences observed in the distributional analyses of post-policy ozone and $PM_{2.5}$ exposure impacts across populations, we do not find evidence that potential EJ concerns related to ozone and $PM_{2.5}$ concentrations will be created or mitigated as compared to the baseline.[418]

C. Outreach and Engagement

Prior to proposal, the EPA hosted an outreach webinar with environmental justice stakeholders to share information about the proposed rule and solicit feedback about potential environmental justice considerations. The webinar was attended by representatives of state governments, federally recognized tribes, environmental NGOs, higher education institutions, industry, and the EPA.[419] Participants were invited to comment on pre-proposal environmental justice considerations during the webinar or submit written comments to a pre-proposal non-regulatory docket.

After proposal, the EPA opened a public comment period to invite the public to submit written comments to the regulatory docket for this rulemaking.[420] The EPA also invited the public to participate in a public hearing held on April 21, 2022. A transcript of the public hearing is available in the docket for this rulemaking. Additionally, on March 31, 2022, the EPA hosted an informational webinar with non-governmental groups and environmental justice stakeholders to answer questions and share information about the proposed rule. A record of this webinar, including the informational power point shared at the webinar is available in the docket for this rulemaking.

VIII. Costs, Benefits, and Other Impacts of the Final Rule

In the *RIA* for the Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards, the EPA estimated the health and climate benefits, compliance costs, and emissions changes that may result from the final rule for the analysis period 2023 to 2042. The estimated health and climate benefits and compliance costs are presented in detail in this *RIA.* The EPA notes that for EGUs the estimated benefits and compliance costs are directly associated with fully operating existing SCRs during ozone season; fully operating existing SNCRs during ozone season; installing state-of-the-art combustion controls; imposing a backstop emissions rate on certain units that lack SCR controls; and installing SCR and SNCR post-combustion controls. The EPA also notes that for non-EGUs the estimated health benefits and compliance costs are directly associated with installing controls to meet the NO_X emissions requirements presented in section I.B of this document.

For EGUs, the EPA analyzed this action's emissions budgets using uniform control stringency represented by $1,800 per ton of NO_X (2016$) in 2023 and $11,000 per ton of NO_X (2016$) in 2026. The EPA also analyzed a more and a less stringent alternative. The more and less stringent alternatives differ from the rule in that they set different NO_X ozone season emissions budgets for the affected EGUs and different dates for large, coal-fired EGUs' compliance with the backstop emissions rate.

For non-EGUs, the EPA developed an analytical framework to determine which industries and emissions unit types to include in a proposed Transport FIP for the 2015 ozone NAAQS transport obligations. A February 28, 2022 memorandum, titled ''Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026,'' documents the analytical framework used to identify industries and emissions unit types included in the proposed FIP. To further evaluate the industries and emissions unit types identified and to establish the proposed emissions limits, the EPA reviewed Reasonably RACT rules, NSPS rules, NESHAP rules, existing technical studies, rules in approved SIP submittals, consent decrees, and permit limits. That evaluation is detailed in the Proposed Non-EGU Sectors TSD prepared for the proposed FIP. The EPA is retaining the industries and many of the emissions unit types included in the proposal in this final action. For the non-EGU industries, in the final rule we made some minor changes to the non-EGU emissions units covered, the applicability criteria, as well as provided for facility-wide emissions averaging for engines and for a low-use exemption to eliminate the need to install controls on low-use boilers.

Table VIII–1 provides the projected 2023 through 2027, 2030, 2035, and 2042 EGU NO_X, SO_2, $PM_{2.5}$, and CO_2 emissions reductions for the evaluated regulatory control alternatives. For additional information on emissions changes, see Table 4–6 and Table 4–7 in Chapter 4 of the *RIA.*

TABLE VIII–1—EGU OZONE SEASON NO_X EMISSIONS CHANGES AND ANNUAL EMISSIONS REDUCTIONS (TONS) FOR NO_X, SO_2, $PM_{2.5}$, AND CO_2 FOR THE REGULATORY CONTROL ALTERNATIVES FROM 2023–2042

	Final rule	Less stringent alternative	More stringent alternative
2023:			
NO_X (ozone season)	10,000	10,000	10,000
NO_X (annual)	15,000	15,000	15,000
SO_2 (annual)	1,000	3,000	1,000
CO_2 (annual, thousand metric tons)	....	....	....

[418] Please note, exposure results should not be extrapolated to other air pollutant. Detailed environmental justice analytical results can be found in Chapter 7 of the RIA.

[419] This does not constitute EPA's tribal consultation under E.O. 13175, which is described in section XI.F of this rule.

[420] Comments and responses regarding environmental justice considerations are available in Section 6 of the *RTC* document for this rulemaking.

TABLE VIII–1—EGU OZONE SEASON NO_X EMISSIONS CHANGES AND ANNUAL EMISSIONS REDUCTIONS (TONS) FOR NO_X, SO_2, $PM_{2.5}$, AND CO_2 FOR THE REGULATORY CONTROL ALTERNATIVES FROM 2023–2042—Continued

	Final rule	Less stringent alternative	More stringent alternative
$PM_{2.5}$ (annual)			
2024:			
NO_X (ozone season)	21,000	10,000	33,000
NO_X (annual)	25,000	15,000	57,000
SO_2 (annual)	19,000	5,000	59,000
CO_2 (annual, thousand metric tons)	10,000	4,000	20,000
$PM_{2.5}$ (annual)	1,000		1,000
2025:			
NO_X (ozone season)	32,000	10,000	56,000
NO_X (annual)	35,000	15,000	99,000
SO_2 (annual)	38,000	7,000	118,000
CO_2 (annual, thousand metric tons)	21,000	8,000	40,000
$PM_{2.5}$ (annual)	2,000	1,000	2,000
2026:			
NO_X (ozone season)	25,000	8,000	49,000
NO_X (annual)	29,000	12,000	88,000
SO_2 (annual)	29,000	5,000	104,000
CO_2 (annual, thousand metric tons)	16,000	6,000	34,000
$PM_{2.5}$ (annual)	1,000		2,000
2027:			
NO_X (ozone season)	19,000	6,000	43,000
NO_X (annual)	22,000	9,000	78,000
SO_2 (annual)	21,000	4,000	91,000
CO_2 (annual, thousand metric tons)	10,000	3,000	28,000
$PM_{2.5}$ (annual)	1,000		2,000
2030:			
NO_X (ozone season)	34,000	33,000	31,000
NO_X (annual)	62,000	59,000	50,000
SO_2 (annual)	93,000	98,000	51,000
CO_2 (annual, thousand metric tons)	26,000	23,000	8,000
$PM_{2.5}$ (annual)	1,000	1,000	
2035:			
NO_X (ozone season)	29,000	30,000	27,000
NO_X (annual)	46,000	46,000	41,000
SO_2 (annual)	21,000	19,000	15,000
CO_2 (annual, thousand metric tons)	16,000	15,000	8,000
$PM_{2.5}$ (annual)	1,000	1,000	
2042:			
NO_X (ozone season)	22,000	22,000	22,000
NO_X (annual)	23,000	22,000	21,000
SO_2 (annual)	15,000	15,000	7,000
CO_2 (annual, thousand metric tons)	9,000	8,000	4,000
$PM_{2.5}$ (annual).			

Emissions changes for NO_X, SO_2, and $PM_{2.5}$ are in tons.

Table VIII–2 provides a summary of the ozone season NO_X emissions for non-EGUs for the 20 states subject to the non-EGU emissions requirements starting in 2026, along with the estimated ozone season NO_X reductions for 2026 for the rule and the less and more stringent alternatives. The analysis in the *RIA* assumes that the estimated reductions in 2026 will be the same in later years.

TABLE VIII–2—OZONE SEASON NO_X EMISSIONS AND EMISSIONS REDUCTIONS (TONS) FOR NON-EGUS FOR THE FINAL RULE AND THE LESS AND MORE STRINGENT ALTERNATIVES

State	2019 Ozone season emissions [a]	Final rule—ozone season NO_X reductions	Less stringent—ozone season NO_X reductions	More stringent—ozone season NO_X reductions
AR	8,790	1,546	457	1,690
CA	16,562	1,600	1,432	4,346
IL	15,821	2,311	751	2,991
IN	16,673	1,976	1,352	3,428
KY	10,134	2,665	583	3,120
LA	40,954	7,142	1,869	7,687
MD	2,818	157	147	1,145
MI	20,576	2,985	760	5,087
MO	11,237	2,065	579	4,716
MS	9,763	2,499	507	2,650

TABLE VIII–2—OZONE SEASON NO_X EMISSIONS AND EMISSIONS REDUCTIONS (TONS) FOR NON-EGUS FOR THE FINAL RULE AND THE LESS AND MORE STRINGENT ALTERNATIVES—Continued

State	2019 Ozone season emissions [a]	Final rule—ozone season NO_X reductions	Less stringent—ozone season NO_X reductions	More stringent—ozone season NO_X reductions
NJ	2,078	242	242	258
NV [421]	2,544	0	0	0
NY	5,363	958	726	1,447
OH	18,000	3,105	1,031	4,006
OK	26,786	4,388	1,376	5,276
PA	14,919	2,184	1,656	4,550
TX	61,099	4,691	1,880	9,963
UT	4,232	252	52	615
VA	7,757	2,200	978	2,652
WV	6,318	1,649	408	2,100
Totals	302,425	44,616	16,786	67,728

[a] The 2019 ozone season emissions are calculated as 5/12 of the annual emissions from the following two emissions inventory files: nonegu_SmokeFlatFile_2019NEI_POINT_20210721_controlupdate_13sep2021_v0 and oilgas_SmokeFlatFile_2019NEI_POINT_20210721_controlupdate_13sep2021_v0.

For EGUs, the EPA analyzed ozone season NO_X emissions reductions and the associated costs to the power sector using the Integrated Planning Model (IPM) and its underlying data and inputs. For non-EGUs, the EPA prepared an assessment summarized in the memorandum titled *Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs,* and the memorandum includes estimated emissions reductions by state for the rule.[421]

Table VIII–3 reflects the estimates of the changes in the cost of supplying electricity for the regulatory control alternatives for EGUs and estimates of complying with the emissions requirements for non-EGUs. The costs presented in Table VIII–3 do not include monitoring and reporting costs, which EPA summarizes in section X.B.2 of this document. The monitoring and reporting costs presented in section X.B.2 are $0.35 million per year for EGUs and $3.8 million per year for non-EGUs. For EGUs, compliance costs are negative in 2026. While seemingly counterintuitive, estimating negative compliance costs in a single year is possible given IPM's objective function is to minimize the discounted net present value (NPV) of a stream of annual total cost of generation over a multi-decadal time period. As such the model may undertake a compliance pathway that pushes higher costs later into the forecast period, since future costs are discounted more heavily than near term costs. This can result in a policy scenario showing single year costs that are lower than the Baseline, but over the entire forecast horizon, the policy scenario shows higher costs.[422] For a detailed description of these cost trends, please see Chapter 4, section 4.5.2, of the *RIA.* For a detailed description of the methods and results from the memorandum titled *Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs,* see Chapter 4, sections 4.4 and 4.5.4 of the *RIA.*

TABLE VIII–3—TOTAL ESTIMATED COMPLIANCE COSTS (MILLION 2016$), 2023–2042

	Final rule	Less-stringent alternative	More-stringent alternative
2023:			
EGUs	57	56	49
Non-EGUs			
Total	57	56	49
2024:			
EGUs	(5)	(35)	840
Non-EGUs			
Total	(5)	(35)	840
2025:			
EGUs	(5)	(35)	840
Non-EGUs			
Total	(5)	(35)	840
2026:			

[421] We are not aware of existing non-EGU emissions units in Nevada that meet the applicability criteria for non-EGUs in the final rule. If any such units in fact exist, they would be subject to the requirements of the rule just as in any other state. In addition, any new emissions unit in Nevada that meets the applicability criteria in the final rule will be subject to the final rule's requirements. See section III.B.1.d.

[422] As a sensitivity, the EPA re-calculated costs assuming annual costs cannot be negative. This resulted in annualized 2023–42 costs under the final rule increasing from $448.6 million to $449.5 million (less than 1%) and did not change the conclusions of the RIA. See Section 4.5.2 of the RIA for more information.

TABLE VIII–3—TOTAL ESTIMATED COMPLIANCE COSTS (MILLION 2016$), 2023–2042—Continued

	Final rule	Less-stringent alternative	More-stringent alternative
EGUs	(5)	(35)	840
Non-EGUs	570	140	1,300
Total	570	110	2,100
2027:			
EGUs	24	(47)	760
Non-EGUs	570	140	1,300
Total	600	97	2,000
2028:			
EGUs	24	(47)	760
Non-EGUs	570	140	1,300
Total	600	97	2,000
2029:			
EGUs	24	(47)	760
Non-EGUs	570	140	1,300
Total	600	97	2,000
2030:			
EGUs	710	770	840
Non-EGUs	570	140	1,300
Total	1,300	920	2,100
2031:			
EGUs	710	770	840
Non-EGUs	570	140	1,300
Total	1,300	920	2,100
2032:			
EGUs	820	850	590
Non-EGUs	570	140	1,300
Total	1,400	990	1,900
2033:			
EGUs	820	850	590
Non-EGUs	570	140	1,300
Total	1,400	990	1,900
2034:			
EGUs	820	850	590
Non-EGUs	570	140	1,300
Total	1,400	990	1,900
2035:			
EGUs	820	850	590
Non-EGUs	570	140	1,300
Total	1,400	990	1,900
2036:			
EGUs	820	850	590
Non-EGUs	570	140	1,300
Total	1,400	990	1,900
2037:			
EGUs	820	850	590
Non-EGUs	570	140	1,300
Total	1,400	990	1,900
2038:			
EGUs	820	830	600
Non-EGUs	570	140	1,300
Total	1,400	970	1,900
2039:			
EGUs	820	830	600
Non-EGUs	570	140	1,300
Total	1,400	970	1,900
2040:			
EGUs	820	830	600

TABLE VIII–3—TOTAL ESTIMATED COMPLIANCE COSTS (MILLION 2016$), 2023–2042—Continued

	Final rule	Less-stringent alternative	More-stringent alternative
Non-EGUs	570	140	1,300
Total	1,400	970	1,900
2041:			
EGUs	820	830	600
Non-EGUs	570	140	1,300
Total	1,400	970	1,900
2042:			
EGUs	820	830	600
Non-EGUs	570	140	1,300
Total	1,400	970	1,900

Tables VIII–4 and VIII–5 report the estimated economic value of avoided premature deaths and illness in each year relative to the baseline along with the 95 percent confidence interval. In each of these tables, for each discount rate and regulatory control alternative, two benefits estimates are presented reflecting alternative ozone and $PM_{2.5}$ mortality risk estimates. For additional information on these benefits, see Chapter 5 of the *RIA.*

TABLE VIII–4—ESTIMATED DISCOUNTED ECONOMIC VALUE OF AVOIDED OZONE-RELATED PREMATURE MORTALITY AND ILLNESS FOR THE FINAL RULE AND THE LESS AND MORE STRINGENT ALTERNATIVES IN 2023

[95 Percent confidence interval; millions of 2016$] [a b]

Disc rate	Pollutant	Final rule	Less stringent alternative	More stringent alternative
3%	Ozone Benefits	$100 [$27 to $220] [c] *and* $820 [$91 to $2,100] [d].	$100 [$27 to $220] [c] *and* $810 [$91 to $2,100] [d].	$110 [$28 to $230] [c] *and* $840 [$94 to $2,200] [d].
7%	Ozone Benefits	$93 [$17 to 210] [c] *and* $730 [$75 to $1,900] [d].	$93 [$17 to $210] [c] *and* $730 [$75 to $1,900] [d].	$96 [$18 to $210] [c] *and* $750 [$77 to $2,000] [d].

[a] Values rounded to two significant figures. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] We estimated ozone benefits for changes in NO_X for the ozone season. This table does not include benefits from reductions for non-EGUs because reductions from these sources are not expected prior to 2026 when the final standards would apply to these sources.
[c] Using the pooled short-term ozone exposure mortality risk estimate.
[d] Using the long-term ozone exposure mortality risk estimate.

TABLE VIII–5—ESTIMATED DISCOUNTED ECONOMIC VALUE OF AVOIDED OZONE AND $PM_{2.5}$-RELATED PREMATURE MORTALITY AND ILLNESS FOR THE FINAL RULE AND THE LESS AND MORE STRINGENT ALTERNATIVES IN 2026

[95% Confidence interval; millions of 2016$] [a b]

Disc rate	Pollutant	Final rule	Less stringent alternative	More stringent alternative
3%	Ozone Benefits	$1,100 [$280 to $2,400] [c] *and* $9,400 [$1,000 to $25,000] [d].	$420 [$110 to $900] [c] *and* $3,400 [$380 to $8,900] [d].	$1,900 [470 to $4,000] [c] *and* $15,000 [$1,700 to $40,000] [d].
	PM Benefits	$2,000 [$220 to $5,300] *and* $4,400 [$430 to $12,000].	$530 [$57 to $1,400] *and* $1,100 [$110 to $3,100].	$6,400 [$690 to $17,000] *and* $14,000 [$1,300 to $37,000]
	Ozone plus PM Benefits.	$3,200 [$500 to $7,700] [c] *and* $14,000 [$1,500 to $36,000] [d].	$950 [$160 to $2,300] [c] *and* $4,600 [$490 to $12,000] [d].	$8,300 [$1,200 to $21,000] [c] *and* $29,000 [$3,000 to $77,000] [d].
7%	Ozone Benefits	$1,000 [$180 to $2,300] [c] *and* $8,400 [$850 to $22,000] [d].	$380 [$68 to $850] [c] *and* $3,100 [$310 to $8,100] [d].	$1,700 [$300 to $3,800] [c] *and* $14,000 [$1,400 to $36,000] [d].
	PM Benefits	$1,800 [$190 to $4,700] *and* $3,900 [$380 to $11,000].	470 [$50 to $1,200] *and* $1,000 [$100 to $2,800].	$5,800 [$600 to $15,000] *and* $12,000 [$1,200 to $33,000].
	Ozone plus PM Benefits.	$2,800 [$370 to $7,000] [c] *and* $12,000 [$1,200 to $33,000] [d].	$850 [$120 to $2,100] [c] *and* $4,100 [$410 to $11,000] [d].	$7,500 [$910 to $19,000] [c] *and* $26,000 [$2,600 to $69,000] [d].

[a] Values rounded to two significant figures. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] We estimated changes in NO_X for the ozone season and annual changes in $PM_{2.5}$ and $PM_{2.5}$ precursors in 2026.
[c] Sum of ozone mortality estimated using the pooled short-term ozone exposure risk estimate and the Di et al. (2017) long-term $PM_{2.5}$ exposure mortality risk estimate.
[d] Sum of the Turner et al. (2016) long-term ozone exposure risk estimate and the Di et al. (2017) long-term $PM_{2.5}$ exposure mortality risk estimate.

In Tables VIII–6, VIII–7, and VIII–8, the EPA presents a summary of the monetized health and climate benefits, costs, and net benefits of the rule and the more and less stringent alternatives for 2023, 2026, and 2030, respectively. There are important water quality benefits and health benefits associated with reductions in concentrations of air pollutants other than ozone and $PM_{2.5}$ that are not quantified. Discussion of the non-monetized health, welfare, and water quality benefits is found in Chapter 5 of the *RIA.* In this action, monetized climate benefits are presented for purposes of providing a complete economic impact analysis under E.O. 12866 and other relevant Executive orders. The estimates of GHG emissions changes and the monetized benefits associated with those changes is not part of the record basis for this action, which is taken to implement the good neighbor provision, CAA section 110(a)(2)(D)(i)(I), for the 2015 ozone NAAQS.

TABLE VIII–6—MONETIZED BENEFITS, COSTS, AND NET BENEFITS OF THE FINAL RULE AND LESS AND MORE STRINGENT ALTERNATIVES FOR 2023 FOR THE U.S.

[3% Discount rate for benefits, millions of 2016$] [a b]

	Final rule	Less stringent alternative	More stringent alternative
Health Benefits [c]	$100 and $820	$100 and $810	$110 and $840.
Climate Benefits	$5	$4	$5.
Total Benefits	$100 and $820	$100 and $820	$110 and $840.
Costs [d]	$57	$56	$49.
Net Benefits	$48 and $760	$48 and $760	$66 and $800.

[a] We focus results to provide a snapshot of costs and benefits in 2023, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Rows may not appear to add correctly due to rounding.
[c] The health benefits are associated with two point estimates from two different epidemiologic studies. For the purposes of presenting the values in this table the health and climate benefits are discounted at 3 percent.
[d] The costs presented in this table are 2023 annual estimates for each alternative analyzed. For EGUs, an NPV of costs was calculated using a 3.76 percent real discount rate consistent with the rate used in IPM's objective function for cost-minimization. For further information on the discount rate use, please see Chapter 4, Table 4–8 in the RIA.

TABLE VIII–7—MONETIZED BENEFITS, COSTS, AND NET BENEFITS OF THE FINAL RULE AND LESS AND MORE STRINGENT ALTERNATIVES FOR 2026 FOR THE U.S.

[3% Discount rate for benefits, millions of 2016$] [a b]

	Final rule	Less stringent alternative	More stringent alternative
Health Benefits [c]	$3,200 and $14,000	$950 and $4,600	$8,300 and $29,000.
Climate Benefits	$1,100	$420	$2,100.
Total Benefits	$4,300 and $15,000	$1,400 and $5,000	$10,000 and $31,000.
Costs [d]	$570	$110	$2,100.
Net Benefits	$3,700 and $14,000	$1,300 and $4,900	$8,300 and $29,000.

[a] We focus results to provide a snapshot of costs and benefits in 2026, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Rows may not appear to add correctly due to rounding.
[c] The health benefits are associated with two point estimates from two different epidemiologic studies. For the purposes of presenting the values in this table the health and climate benefits are discounted at 3 percent.
[d] The costs presented in this table are 2026 annual estimates for each alternative analyzed. For EGUs, an NPV of costs was calculated using a 3.76 percent real discount rate consistent with the rate used in IPM's objective function for cost-minimization. For further information on the discount rate use, please see Chapter 4, Table 4–8 in the RIA.

TABLE VIII–8—MONETIZED BENEFITS, COSTS, AND NET BENEFITS OF THE FINAL RULE AND LESS AND MORE STRINGENT ALTERNATIVES FOR 2030 FOR THE U.S.

[3% Discount rate for benefits, millions of 2016$] [a b]

	Final rule	Less stringent alternative	More stringent alternative
Health Benefits [c]	$3,400 and $15,000	$1,000 and $4,900	$9,000 and $31,000.
Climate Benefits	$1,500	$1,300	$500.
Total Benefits	$4,900 and $16,000	$2,300 and $6,200	$9,500 and $31,000.
Costs [d]	$1,300	$920	$2,100.
Net Benefits	$3,600 and $15,000	$1,400 and $5,300	$7,400 and $29,000.

[a] We focus results to provide a snapshot of costs and benefits in 2030, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Rows may not appear to add correctly due to rounding.
[c] The health benefits are associated with two point estimates from two different epidemiologic studies. For the purposes of presenting the values in this table the health and climate benefits are discounted at 3 percent.
[d] The costs presented in this table are 2030 annual estimates for each alternative analyzed. For EGUs, an NPV of costs was calculated using a 3.76 percent real discount rate consistent with the rate used in IPM's objective function for cost-minimization. For further information on the discount rate use, please see Chapter 4, Table 4–8 in the RIA.

In addition, Table VIII–9 presents estimates of the present value (PV) of the monetized benefits and costs and the equivalent annualized value (EAV), an estimate of the annualized value of the net benefits consistent with the present value, over the twenty-year period of 2023 to 2042. The estimates of the PV and EAV are calculated using discount rates of 3 and 7 percent as recommended by OMB's Circular A–4 and are presented in 2016 dollars discounted to 2023.

TABLE VIII–9—MONETIZED ESTIMATED HEALTH AND CLIMATE BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS OF THE FINAL RULE AND LESS AND MORE STRINGENT ALTERNATIVES, 2023 THROUGH 2042

[Millions 2016$, discounted to 2023]

	3 Percent discount rate		7 Percent discount rate	
	PV	EAV	PV	EAV
Health benefits				
Final Rule	$200,000	$13,000	$130,000	$12,000
Less Stringent Alternative	67,000	4,500	40,000	3,800
More Stringent Alternative	410,000	28,000	240,000	23,000
Climate Benefits [a]				
Final Rule	15,000	970	15,000	970
Less Stringent Alternative	11,000	770	11,000	770
More Stringent Alternative	14,000	920	14,000	920
Compliance Costs				
Final Rule	14,000	910	9,400	770
Less Stringent Alternative	8,700	590	5,300	500
More Stringent Alternative	25,000	1,700	17,000	1,600
Net Benefits				
Final Rule	200,000	13,000	140,000	12,000
Less Stringent Alternative	70,000	4,700	42,000	4,000
More Stringent Alternative	400,000	27,000	240,000	22,000

[a] Climate benefits are calculated using four different estimates of the social cost of carbon (SC–CO_2) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For presentational purposes in this table, the climate benefits associated with the average SC–CO_2 at a 3-percent discount rate are used in the columns displaying results of other costs and benefits that are discounted at either a 3-percent or 7-percent discount rate.

As shown in Table VIII–9, the PV of the monetized health benefits of this rule, discounted at a 3-percent discount rate, is estimated to be about $200 billion ($200,000 million), with an EAV of about $13 billion ($13,000 million). At a 7-percent discount rate, the PV of the monetized health benefits is estimated to be $130 billion ($130,000 million), with an EAV of about $12 billion ($12,000 million). The PV of the monetized climate benefits of this rule, discounted at a 3-percent discount rate, is estimated to be about $15 billion ($15,000 million), with an EAV of about $970 million. The PV of the monetized compliance costs, discounted at a 3-percent rate, is estimated to be about $14 billion ($14,000 million), with an EAV of about $910 million. At a 7-percent discount rate, the PV of the compliance costs is estimated to be about $9.4 billion ($9,400 million), with an EAV of about $770 million.

In addition to the analysis of costs and benefits as described above, for the final rule, the EPA was able to conduct a full-scale photochemical grid modeling run of the effects of the ''final rule'' emissions control scenario in 2026. This modeling can be used to estimate the impacts on projected 2026 ozone design values that are expected from the combined EGU and non-EGU control emissions reductions in this final rule. These results do not replace the AQAT-generated estimates used for our Step 3 determinations, and the EPA needed to continue to use AQAT for Step 3 determinations in order to characterize various potential control scenarios to inform these regulatory determinations. Nonetheless, though they differ slightly from the AQAT-generated air quality estimates of the final rule control scenario conducted for purposes of our Step 3 analysis (as presented in section V.D of this document), these results using full-scale photochemical grid modeling complement those estimates and confirm in all cases the regulatory conclusions reached applying AQAT.[423] Appendix 3A of the *RIA* presents the full results of the projected impacts of the final rule control scenario on ozone levels using CAMx. To briefly summarize, the largest reductions in ozone design values at identified receptors are predicted to occur in the Houston-Galveston-Brazoria, Texas area. In this area the reductions from the final rule case range from 0.7 to 0.9 ppb. At most of the receptors in both the Dallas/Ft Worth and the New York/Coastal Connecticut areas the reductions in ozone range from 0.4 to 0.5 ppb. At receptors in Indiana, Michigan, and Wisconsin near the shoreline of Lake Michigan, ozone is projected to decline by 0.3 to 0.4 ppb, but by as much as 0.5 ppb at the receptor in Muskegon, MI. Reductions of 0.1 ppb are predicted in the urban and near-urban receptors in Chicago. In the West, ozone reductions just under 0.2 ppb are predicted at receptors in Denver with slightly greater reductions, just above 0.2 ppb, at receptors in Salt Lake City. At receptors in Phoenix, California, El Paso/Las Cruces, and southeast New Mexico the reductions in ozone are predicted to be less than 0.1 ppb.

[423] Note that the EPA's ''overcontrol'' analysis relies primarily on a ''Step 3'' control scenario rather than the ''full geography'' scenario. The CAMx modeling described here captures the effects of the rule as a whole and so is more akin to the ''full geography'' scenario, which the EPA does not believe is the appropriate method for conducting overcontrol analysis. Nonetheless, as explained in the Ozone Transport Policy Analysis Final Rule TSD, the results under either scenario establish no overcontrol, and the CAMx results presented here do not call those conclusions into question.

IX. Summary of Changes to the Regulatory Text for the Federal Implementation Plans and Trading Programs for EGUs

This section describes the amendments to the regulatory text that implement the findings and remedy discussed elsewhere in this rule with respect to EGUs. The primary CFR amendments are revisions to the FIP provisions addressing states' good neighbor obligations related to ozone in 40 CFR part 52 as well as the revisions to the regulations for the CSAPR NO_X Ozone Season Group 3 Trading Program in 40 CFR part 97, subpart GGGGG. In conjunction with the amendments to the Group 3 trading program, the monitoring, recordkeeping, and reporting regulations in 40 CFR part 75 are being amended to reflect the addition of certain new reporting requirements associated with the amended trading program and the administrative appeal provisions in 40 CFR part 78 are being amended to identify certain additional types of appealable decisions of the EPA Administrator under the amended trading program. The provisions to address the transition of the EGUs in certain states from the Group 2 trading program to the Group 3 trading program are implemented in part through revisions to the regulations noted previously and in part through revisions to the regulations for the Group 2 trading program in 40 CFR part 97, subpart EEEEE.

In addition to these primary amendments, certain revisions are being made to the regulations for the other CSAPR trading programs in 40 CFR part 97, subparts AAAAA through EEEEE, for conformity with the amended provisions of the Group 3 trading program, as discussed in section VI.B.13. Documents have been included in the docket for this rule showing all of the revisions in redline-strikeout format.

A. Amendments to FIP Provisions in 40 CFR Part 52

The CSAPR, CSAPR Update, and Revised CSAPR Update FIP requirements related to ozone season NO_X emissions are set forth in 40 CFR 52.38(b) as well as other sections of part 52 specific to each covered state. The existing text of § 52.38(b)(1) identifies the trading program regulations in 40 CFR part 97, subparts BBBBB, EEEEE, and GGGGG, as constituting the relevant FIP provisions relating to seasonal NO_X emissions and transported ozone pollution. Because in this rulemaking the EPA is establishing new or amended FIP requirements not only for the types of EGUs covered by the trading programs but also for certain types of industrial sources, an amendment to § 52.38(b)(1) clarifies that the trading programs constitute the FIP provisions only for the sources meeting the applicability requirements of the trading programs. A parallel clarification is being added to §§ 52.38(a)(1) and 52.39(a) with respect to the CSAPR FIP requirements relating to annual NO_X emissions, SO_2 emissions, and transported fine particulate pollution.

The states whose EGU sources are required to participate in the CSAPR NO_X Ozone Season Group 1, Group 2, and Group 3 trading programs under the FIPs established in CSAPR, the CSAPR Update, and the Revised CSAPR Update, as well as the control periods for which those requirements apply, are identified in § 52.38(b)(2). The amendments to this paragraph expand the applicability of the Group 3 trading program to sources in the ten additional states that the EPA is adding to the Group 3 trading program starting with the 2023 control period and end the applicability of the Group 2 trading program (with the exception of certain provisions) for sources in seven of the ten states after the 2022 control period, as discussed in section VI.B.2.[424] The paragraphs within § 52.38(b)(2) are being renumbered to clarify the organization of the provisions and to facilitate cross-references from other regulatory provisions. Regarding the two states currently participating in the Group 2 trading program through approved SIP revisions that replaced the previous FIPs issued under the CSAPR Update (Alabama and Missouri), a provision indicating that the EPA will no longer administer the state trading programs adopted under those SIP revisions after the 2022 control period is being added at § 52.38(b)(16)(ii)(B).

In the Revised CSAPR Update, the EPA established several options for states to revise their SIPs to modify or replace the FIPs applicable to their sources while continuing to use the Group 3 trading program as the mechanism for meeting the states' good neighbor obligations. As in effect before this rule, § 52.38(b)(10), (11), and (12) established options to replace allowance allocations for the 2022 control period, to adopt an abbreviated SIP revision for control periods in 2023 or later years, and to adopt a full SIP revision for control periods in 2023 or later years, respectively.[425] As discussed in section VI.D, the EPA is retaining these SIP revision options and is making them available for all states covered by the Group 3 trading program after the geographic expansion. The option under § 52.38(b)(10) to replace allowance allocations for a single control period is being amended to be available for the 2024 control period, with attendant revisions to the years and dates shown in § 52.38(b)(10) (multiple paragraphs) and (b)(17)(i) as well as the Group 3 trading program regulations, as discussed in section IX.B. The options under § 52.38(b)(11) and (12) to adopt abbreviated or full SIP revisions are being amended to be available starting with the 2025 control period, with attendant revisions to § 52.38(b)(11)(iii), (b)(12)(iii), and (b)(17)(ii).[426] The removal of the previous options for states to expand applicability of the trading programs for ozone season NO_X emissions to certain non-EGUs and smaller EGUs, discussed in sections VI.D.2 and VI.D.3, is accomplished by the removal or revision of multiple paragraphs of § 52.38(b), including most notably the removal of § 52.38(b)(4)(i), (b)(5)(i), (b)(8)(i)–(ii), (b)(9)(i)–(ii), (b)(11)(i)–(iii), and (b)(12)(i)–(iii).

The changes with respect to set-asides and the treatment of units in Indian country discussed in section VI.B.9, although implemented largely through amendments to the Group 3 trading program regulations, are also implemented in part through amendments to § 52.38(b)(11) and (12). First, the text in § 52.38(b)(11)(iii)(A) and (b)(12)(iii)(A) identifying the portion of each state trading budget for which a state may establish state-determined allowance allocations is being revised to exclude any allowances in a new unit set-aside or Indian country existing unit set-aside. Second, the text in § 52.38(b)(12)(vi) identifying provisions that states may not adopt into their SIPs (because the provisions concern regulation of sources in Indian country not subject to a state's CAA implementation planning authority) are being revised to include the provisions of the amended Group 3 trading program addressing allocation and recordation of allowances from all types of set-asides. Finally, the text in § 52.38(b)(12)(vii) authorizing the EPA to modify the previous approval of a SIP revision with regard to the assurance provisions ''if and when a covered unit is located in Indian country'' are being revised to account for the fact that at least one covered unit is already located in Indian country not subject to a state's CAA planning authority.

The transitional provisions discussed in sections VI.B.12.b and VI.B.12.c to

[424] Like the previous text of § 52.38(b)(2), the final amended text expressly encompasses sources in Indian country within the respective states' borders.

[425] Revisions to the deadlines for states with approved SIP revisions to submit their state-determined allowance allocations to the EPA for subsequent recordation were finalized in an earlier final rule in this docket. See 87 FR 52473 (August 26, 2022).

[426] No state currently in the Group 3 trading program has submitted a SIP revision to make use of these options in control periods before the control periods in which the options can be used under the amended provisions.

convert certain 2017–2022 Group 2 allowances to Group 3 allowances and to recall certain 2023–2024 Group 2 allowances, although promulgated as amendments to the Group 2 trading program regulations, will necessarily be implemented after the end of the 2022 control period. Amendments clarifying that these provisions continue to apply to the relevant sources and holders of allowances notwithstanding the transition of certain states out of the Group 2 trading program after the 2022 control period are being added at § 52.38(b)(14)(iii). Cross-references clarifying that the EPA's allocations of the converted Group 3 allowances are not subject to modification through SIP revisions are also being added to the existing provisions at § 52.38(b)(11)(iii)(D) and (b)(12)(iii)(D).

The general FIP provisions applicable to all states covered by this rule as set forth in § 52.38(b)(2) are being replicated in the state-specific subparts of 40 CFR part 52 for each of the ten states that the EPA is adding to the Group 3 trading program.[427] In each such state-specific CFR subpart, provisions are being added indicating that sources in the state are required to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program with respect to emissions starting in 2023. Provisions are also being added repeating the substance of § 52.38(b)(13)(i), which generally provides that the Administrator's full and unconditional approval of a full SIP revision correcting the same SIP deficiency that is the basis for a FIP promulgated in this rulemaking would cause the FIP to no longer apply to sources subject to the state's CAA implementation planning authority, and § 52.38(b)(14)(ii), which generally provides the EPA with authority to complete recordation of EPA-determined allowance allocations for any control period for which EPA has already started such recordation notwithstanding the approval of a state's SIP revision establishing state-determined allowance allocations.

For each of the seven states that the EPA is removing from the Group 2 trading program, the provisions of the state-specific CFR subparts indicating that sources in the state are required to participate in that trading program are being revised to end that requirement with respect to emissions after 2022, and a further provision is being added repeating the substance of § 52.38(b)(14)(iii), which identifies certain provisions that continue to apply to sources and allowances notwithstanding discontinuation of a trading program with respect to a particular state.[428] In addition, for the five states that during their time in the Group 2 trading program have not exercised the option to adopt full SIP revisions to replace the FIPs issued under the CSAPR Update (all but Alabama and Missouri), obsolete provisions concerning the unexercised SIP revision option are being removed.

No amendments with respect to FIP requirements for EGUs are being made to the state-specific CFR subparts for the twelve states whose sources currently participate in the Group 3 trading program[429] except as needed to update cross-references or to implement the changes related to the treatment of Indian country, as discussed in section IX.D.

B. Amendments to Group 3 Trading Program and Related Regulations

To implement the geographic expansion of the Group 3 trading program and the revised trading budgets that are being established under the new and amended FIPs in this rulemaking, several sections of the Group 3 trading program regulations are being amended. Revisions identifying the applicable control periods, deadlines for certification of monitoring systems, and deadlines for commencement of quarterly reporting for sources not previously covered by the Group 3 trading program are being made at §§ 97.1006(c)(3)(i), 97.1030(b)(1), and 97.1034(d)(2)(i), respectively. Revisions identifying the new or revised budgets and new unit set-asides for the control periods after 2022 for all covered states are being made at § 97.1010(a)(1) and (c)(2), respectively.

Each of the enhancements to the Group 3 trading program discussed in section VI.B is also implemented primarily through revisions to the trading program regulations. The dynamic budget-setting process discussed in sections VI.B.1.b.i and VI.B.4 is implemented at § 97.1010(a)(2) through (4), and the associated revised process for determining variability limits and assurance levels discussed in section VI.B.5 is implemented at § 97.1010(e). The Group 3 allowance bank recalibration process discussed in sections VI.B.1.b.ii and VI.B.6 is implemented at § 97.1026(d). The backstop daily NO_X emissions rate component of the primary emissions limitation discussed in sections VI.B.1.c.i and VI.B.7 is implemented at §§ 97.1006(c)(1)(i) and 97.1024(b)(1) and (3), accompanied by the addition of a definition of ''backstop daily NO_X emissions rate'' and modification of the definition of ''CSAPR NO_X Ozone Season Group 3 allowance'' in §§ 97.1002 and 97.1006(c)(6). The secondary emissions limitation for sources found responsible for exceedances of the assurance levels discussed in sections VI.B.1.c.ii and VI.B.8 is implemented at §§ 97.1006(c)(1)(iii) and (iv) and (c)(3)(ii) and 97.1025(c), accompanied by the addition of a definition of ''CSAPR NO_X Ozone Season Group 3 secondary emissions limitation'' in § 97.1002.

The changes relating to set-asides, the treatment of Indian country, and unit-level allowance allocations discussed in section VI.B.9 of this document are implemented through revisions to multiple paragraphs of §§ 97.1010, 97.1011, and 97.1012, as well as limited revisions to §§ 97.1002 (definition of ''allocate or allocation'') and 97.1006(b)(2). In § 97.1010, paragraphs (b), (c), and (d) address the amounts for each control period of the Indian country existing unit set-asides, new unit set-asides, and Indian country new unit set-asides, respectively.[430] Paragraphs (b) and (d) reflect the establishment of Indian country existing unit set-asides starting with the 2023 control period and the discontinuation of Indian country new unit set-asides after the 2022 control period.

A newly added definition at § 97.1002 for ''coal-derived fuel'' (based on the existing definition in 40 CFR 72.2) helps in implementation of both the backstop daily NO_X emissions rate provisions and the unit-level allocation provisions by clarifying that the provisions apply without regard to how any coal combusted by a unit might have been processed before combustion. Another newly added definition at § 97.1002 for ''historical control period'' helps in implementation of the dynamic budget-setting provisions, the secondary emissions limitation provisions, and the

[427] *See* §§ 52.54(b) (Alabama), 52.184(a) (Arkansas), 52.1240(d) (Minnesota), 52.1824(a) (Mississippi), 52.1326(b) (Missouri), 52.1492 (Nevada), 52.1930(a) (Oklahoma), 52.2283(d) (Texas), 52.2356 (Utah), and 52.2587(e) (Wisconsin).

[428] *See* §§ 52.54(b) (Alabama), 52.184(a) (Arkansas), 52.1824(a) (Mississippi), 52.1326(b) (Missouri), 52.1930(a) (Oklahoma), 52.2283(d) (Texas), and 52.2587(e) (Wisconsin).

[429] *See* §§ 52.731(b) (Illinois), 52.789(b) (Indiana), 52.940(b) (Kentucky), 52.984(d) (Louisiana), 52.1084(b) (Maryland), 52.1186(e) (Michigan), 52.1584(e) (New Jersey), 52.1684(b) (New York), 52.1882(b) (Ohio), 52.2040(b) (Pennsylvania), 52.2440(b) (Virginia), and 52.2540(b) (West Virginia).

[430] The former § 97.1011(c), which addresses the relationships of set-asides and variability limits to state trading budgets, is being relocated to § 97.1011(f).

unit-level allocation provisions by facilitating references to data reported by a unit for periods before the unit's entry into the Group 3 trading program.

The revisions to § 97.1011 refocus the section exclusively on allocation to ''existing'' units from the portion of each state emissions budget not reserved in a new unit set-aside or Indian country new unit set-aside. In § 97.1011(a), the provision formerly in § 97.1011(a)(1) requiring allocations to existing units to be made in the amounts provided in NODAs issued by the EPA is being split into two separate provisions, with paragraph (a)(1) applying to existing units in the state and areas of Indian country covered by the state's CAA implementation planning authority and paragraph (a)(2) applying to existing units in areas of Indian country not covered by the state's CAA implementation planning authority.[431] This split will facilitate the submission and approval of SIP revisions by states interested in submitting state-determined allowance allocations for the units over which they exercise CAA implementation authority, while leaving allocations to any units outside their authority to be addressed either by the EPA or by the relevant tribe under an approved tribal implementation plan. The process for determining default allocations to existing units of allowances from state trading budgets starting with the 2026 control period is set forth in revised § 97.1011(b), while the former provisions of § 97.1011(b), which concern timing and notice procedures for allocations to new units, are being relocated to § 97.1012. The provisions addressing incorrectly allocated allowances at § 97.1011(c) are being streamlined by relocating the portions applicable to new units to § 97.1012(c). In addition, as discussed in section VI.B.9.d, § 97.1011(c)(5) is being revised to provide that, starting with the 2024 control period, any incorrectly allocated allowances recovered after May 1 of the year following the control period will not be reallocated to other units in the state but instead would be transferred to a surrender account.

The revisions to § 97.1012 retain the section's current focus on allocations to ''new'' units, generally combining the former provisions at § 97.1012 with the former provisions at § 97.1011(b) and (c) that address new units. The text of multiple paragraphs in both § 97.1012(a) and (b) is being revised as needed to reflect the change in treatment of Indian country discussed in section VI.B.9.a, under which the new unit set-asides will be used to provide allowance allocations to new units both in non-Indian country and Indian country within the borders of the respective states for control periods starting in 2023.[432] The timing and notice provisions in § 97.1012(a)(13) and (b)(13) are relocated from former § 97.1011(b)(1) and (2). The text of § 97.1012(c), addressing incorrect allocations to new units, is largely relocated from § 97.1011(c) (which addresses incorrect allocations to existing units) and reflects a parallel revision addressing the disposition of recovered allowances, as discussed in section VI.B.9.d.

The amendments to § 97.1021 implement two distinct sets of changes discussed in sections VI.B.9 and VI.D.1. First, revisions to § 97.1021(b) through (e) replace the previous schedule for recording Group 3 allowances for the 2023 and 2024 control periods established in the August 2022 Recordation Rule with an updated recordation schedule tailored to the effective date of this rule. The updated schedule also eliminates the unused former option for states to provide state-determined allowance allocations for the 2022 control period and establishes a substantively equivalent new option for states to provide state-determined allowance allocations for the 2024 control period. Second, revisions to § 97.1021(g) through (j) begin recordation for Indian country existing unit set-asides starting with allocations for the 2023 control period, modify the text to eliminate references to state-determined allocations of allowances from new unit set-asides, and end recordation for Indian country new unit set-asides after allocations for the 2022 control period.

Implementation of the revisions to the Group 3 trading program is also accomplished in part through amendments to regulations in other CFR parts. In 40 CFR part 75, which contains detailed monitoring, recordkeeping, and reporting requirements applicable to sources covered by the Group 3 trading program, the additional recordkeeping and reporting requirements discussed in section VI.B.10 of this document are implemented through the addition of §§ 75.72(f) and 75.73(f)(1)(ix) and (x) and revisions to § 75.75, and the procedures for calculating daily total heat input and daily total NO_X emissions and the procedures for apportioning NO_X mass emissions monitored at a common stack among the individual units using the common stack are being added at sections 5.3.3, 8.4(c), and 8.5.3 of appendix F to part 75. In 40 CFR part 78, which contains the administrative appeal procedures applicable to decisions of the EPA Administrator under the Group 3 trading program, § 78.1(b)(19) is being amended to add calculation of the dynamic budgets to the list of administrative decisions under the trading program regulations that will be appealable under those procedures.

C. Transitional Provisions

As discussed in section VI.B.12, the EPA is establishing several transitional provisions for sources entering the Group 3 trading program. The provisions discussed in section VI.B.12.a of this document, concerning the prorating of state emissions budgets, assurance levels, and unit-level allocations for the 2023 control period, are implemented through the Group 3 trading program regulations. Specifically, the state emissions budgets for the 2023 control period will be prorated according to procedures set out at § 97.1010(a)(1)(ii). Variability limits for the 2023 control period, and the resulting assurance levels, will be computed under § 97.1010(e) from the prorated state emissions budgets. Unit-level allocations to existing units for the 2023 control period will be computed from the prorated state emissions budgets according to procedures substantively the same as the procedures codified in § 97.1011(b) for calculating default allocations to existing units for later control periods, as discussed in section VI.B.9.b, and will be announced in the notice of data availability issued under § 97.1011(a)(1) and (2) for the 2023 through 2025 control periods.

The remaining transitional provisions are being implemented through the Group 2 trading program regulations.

[431] An additional provision currently in § 97.1011(a)(1), which clarifies that an allocation or lack of allocation to a unit in a NODA does not constitute a determination by the EPA that the unit is or is not a CSAPR NO_X Ozone Season Group 3 unit, is being relocated to § 97.1011(a)(3). The former § 97.1011(a)(2), which provides for certain existing units that cease operations to receive allocations for their first five control periods of non-operation and provides for the allowances for subsequent control periods to be allocated to the relevant state's new unit set-asides, is inconsistent with the proposed revisions to the set-asides and the default allowance allocation process, as discussed in section VI.B.9, and is being removed as obsolete.

[432] Revisions are also being made to the text of § 97.1012(a) and (b) for the control periods in 2021 and 2022 consistent with the revisions to the parallel provisions in the regulations for the other CSAPR trading programs, generally calling for allocations to units in areas of Indian country subject to a state's CAA implementation planning authority to be made from the new unit set-asides instead of from the Indian country new unit set-asides.

The creation of an additional Group 3 allowance bank for the 2023 control period through the conversion of banked 2017–2022 Group 2 allowances as discussed in section VI.B.12.b of this document is implemented at § 97.826(e).[433] Related provisions addressing the use of Group 3 allowances to satisfy after-arising compliance obligations under the Group 2 trading program or the Group 1 trading program are implemented at §§ 97.826(f)(2) and 97.526(e)(3), respectively, and related provisions addressing recordation of late-arising allocations of Group 1 allowances are implemented at § 97.526(d)(2)(iii). The recall of Group 2 allowances previously issued for the 2023 and 2024 control periods as discussed in section VI.B.12.c of this document is implemented at § 97.811(e).

Decisions of the Administrator related to the allowance bank creation provisions and the allowance recall provisions are identified as appealable decisions under 40 CFR part 78 through revisions to § 78.1(b)(17)(viii) and (ix).

D. Clarifications and Conforming Revisions

As discussed in section VI.B.13 of this document, the EPA is revising the provisions regarding allowance allocations for units in Indian country in all the CSAPR trading programs so that instead of distinguishing among units based on whether they are or are not located in Indian country, the revised provisions distinguish among units based on whether they are or are not covered by a state's CAA implementation planning authority. The revisions are implemented in multiple paragraphs of §§ 97.411(b), 97.412, 97.511(b), 97.512, 97.611(b), 97.612, 97.711(b), 97.712, 97.811(b), and 97.812. The associated revisions to states' options regarding SIP revisions to establish state-determined allowance allocations for units covered by their CAA implementation planning authority are implemented in multiple paragraphs of §§ 52.38(a) and (b) and 52.39 as well as the state-specific subparts of 40 CFR part 52.

Certain other revisions to the regulatory text in the FIP and trading program regulations are minor simplifications and clarifications. First, in the Group 2 trading program regulations, the paragraphs in § 97.810 setting forth the amounts of state emissions budgets, new unit set-asides, Indian country new unit set-asides, and variability limits for states that the EPA is transitioning out of the Group 2 trading program are being modified to indicate that the amounts are applicable under that program only for control periods through 2022.

Second, as noted in sections VI.D.2 and VI.D.3, the existing options for states subject to the NO_X SIP Call to expand applicability of the Group 2 trading program to include certain non-EGUs and smaller EGUs are being eliminated. While the most directly affected provisions are the provisions setting forth the SIP options at § 52.38(b)(4), (5), (8), (9), (12), and (13), as discussed in section IX.A of this document, the changes also render references to ''base'' units and ''base'' sources in the regulations for the Group 2 trading program and the Group 3 trading program obsolete. Removal of the references to ''base'' units and ''base'' sources affects multiple paragraphs of §§ 97.802, 97.806, 97.825, 97.1002, 97.1006, and 97.1025.

Third, to clarify the regulatory text, the EPA is removing the language in the Group 3 trading program regulations that formerly appeared at §§ 97.1002 (definition of ''common designated representative's assurance level''), 97.1006(c)(2)(iii), 97.1010(d), and 97.1011(a)(1) referencing supplemental amounts of allowances issued for the 2021 control period and associated increments to the 2021 assurance levels (each state's assurance level increment was described as 21 percent of the state's supplemental amount of allowances). In place of the removed language, the EPA is restating the amounts of the 2021 state emissions budgets in § 97.1010(a)(1)(i) so as to include the supplemental amounts of allowances and is restating the amounts of the 2021 variability limits in § 97.1010(e)(1) so as to include the associated assurance level increments. The revised language is substantively equivalent to and simpler than the previous language.

Fourth, in 40 CFR part 75, the EPA is removing obsolete text in § 75.73(c) and (f) to clarify the context for other text being added to the section, as discussed in section IX.B of this document.

Fifth, in 40 CFR part 52, the EPA is adding §§ 52.38(a)(7)(iii) and 52.39(k)(3) to clarify in §§ 52.38 and 52.39 that the Allowance Management System housekeeping provisions added by the Revised CSAPR Update at §§ 97.426(c), 97.626(c), and 97.726(c) in the regulations for the CSAPR NO_X Annual, SO_2 Group 1, and SO_2 Group 2 trading programs, respectively, continue to apply after the sources in a given state have been removed from the programs, consistent with the text of the latter provisions.

Finally, the EPA is updating cross-references throughout 40 CFR parts 52 and 97 for consistency with the other amendments being made in this rulemaking.

X. Statutory and Executive Orders Reviews

Additional information about these statutes and Executive orders (''E.O.'') can be found at *https://www2.epa.gov/laws-regulations/laws-and-executive-orders*.

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is a significant regulatory action within the scope of section 3(f)(1) of Executive Order 12866 that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to Executive Order 12866 review have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, which is contained in the ''Regulatory Impact Analysis for Final Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard'' [EPA–452–R–23–001], is available in the docket and is briefly summarized in section VIII of this document.

B. Paperwork Reduction Act (PRA)

1. Information Collection Request for Electric Generating Units

The information collection activities in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2709.01. The EPA has placed a copy of the ICR in the docket for this rule, and it is briefly summarized here.

The EPA is finalizing an information collection request (ICR), related specifically to electric generating units (EGU), for the Federal ''Good Neighbor Plan'' for the 2015 Ozone National Ambient Air Quality Standards. The rule would amend the Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 3 trading program addressing seasonal NO_X emissions in various states. Under the amendments, all EGU sources in the original twelve Group 3 states (Illinois, Indiana,

[433] The provision formerly at § 97.826(e)(1) is being relocated to § 97.826(f)(1), and the provision formerly at § 97.826(e)(2) is being removed as no longer necessary.

Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia) would remain. Additionally, EGU sources in seven states (Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin) currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program would transition from the Group 2 program to the revised Group 3 trading program beginning with the 2023 ozone season. Further, sources in three states not currently covered by any CSAPR NO_X ozone season trading program would join the revised Group 3 trading program: Minnesota, Nevada, and Utah. In total, EGU sources in 22 states would now be covered by the Group 3 program.

There is an existing ICR (OMB Control Number 2060–0667), that includes information collection requirements placed on EGU sources for the six Cross-State Air Pollution Rule (CSAPR) trading programs addressing sulfur dioxide (SO_2) emissions, annual nitrogen oxides (NO_X) emissions, or seasonal NO_X emissions in various sets of states, and the Texas SO_2 trading program which is modeled after CSAPR. This ICR accounts for the additional respondent burden related to the amendments to the CSAPR NO_X Ozone Group 3 trading program.

The principal information collection requirements under the CSAPR and Texas trading programs relate to the monitoring and reporting of emissions and associated data in accordance with 40 CFR part 75. Other information collection requirements under the programs concern the submittal of information necessary to allocate and transfer emissions allowances and the submittal of certificates of representation and other typically one-time registration forms.

Affected sources under the CSAPR and Texas trading programs are generally stationary, fossil fuel-fired boilers and combustion turbines serving generators larger than 25 megawatts (MW) producing electricity for sale. Most of these affected sources are also subject to the Acid Rain Program (ARP). The information collection requirements under the CSAPR and Texas trading programs and the ARP substantially overlap and are fully integrated. The burden and costs of overlapping requirements are accounted for in the ARP ICR (OMB Control Number 2060–0258). Thus, this ICR accounts for information collection burden and costs under the CSAPR NO_X Ozone Season Group 3 trading program that are incremental to the burden and costs already accounted for in both the ARP and CSAPR ICRs.

For most sources already reporting data under the CSAPR NO_X Ozone Season Group 3 or the CSAPR NO_X Ozone Group 2 trading programs, the reporting requirements will remain identical so there will be no incremental burden or cost. Certain sources currently reporting data will be subject to additional emissions reporting requirements under the rule requiring these sources to make a one-time monitoring plan and DAHS update. These sources include those with a common stack configuration and/or those that are large, coal-fired EGUs. Additionally, sources with a common stack configuration have the option to install additional monitoring equipment to measure emissions at each individual unit within the facility, and for purposes of estimating information collection costs and burden, the EPA assumes certain sources will utilize this option. Finally, the assessment of incremental cost and burden are required for those sources in the three states not currently reporting data under a CSAPR NO_X Ozone Season program. Sources in Minnesota are already reporting data for the CSAPR NO_X Annual program with almost identical information collection requirements, requiring only a one-time monitoring plan and DAHS update. Most of the affected sources in Nevada and Utah are already reporting data as part of the Acid Rain Program, thus only requiring a monitoring plan and DAHS update as well. There are a small number of sources in Nevada and Utah that do not report emissions data to the EPA under 40 CFR part 75 and will need to implement a Part 75 monitoring methodology which includes burdens related to installation, certification, and necessary updates.

Respondents/affected entities: Industry respondents are stationary, fossil fuel-fired boilers and combustion turbines serving electricity generators subject to the CSAPR and Texas trading programs, as well as non-source entities voluntarily participating in allowance trading activities. Potential state respondents are states that can elect to submit state-determined allowance allocations for sources located in their states.

Respondent's obligation to respond: Industry respondents: voluntary and mandatory (sections 110(a) and 301(a) of the Clean Air Act).

Estimated number of respondents: The EPA estimates that there would be 120 industry respondents.

Frequency of response: on occasion, quarterly, and annually.

Total estimated additional burden: 2,289 hours (per year). Burden is defined at 5 CFR 1320.03(b).

Total estimated additional cost: $356,623 (per year); includes $182,379 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

2. Information Collection Request for Non-Electric Generating Units

The information collection activities in this final rule have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2705.02. The EPA has filed a copy of the non-EGU ICR in the docket for this rule, and it is briefly summarized here.

ICR No. 2705.02 is a new request and it addresses the burden associated with new regulatory requirements under the final rule. Owners and operators of certain non-Electric Generating Unit (non-EGU) industry stationary sources will potentially modify or install new emissions controls and associated monitoring systems to meet the nitrogen oxides (NO_X) emissions limits of this final rule. The burden in this ICR reflects the new monitoring, calibrating, recordkeeping, reporting and testing activities required of covered industrial sources. This information is being collected to assure compliance with the final rule. In accordance with the Clean Air Act Amendments of 1990, any monitoring information to be submitted by sources is a matter of public record. Information received and identified by owners or operators as confidential business information (CBI) and approved as CBI by the EPA, in accordance with 40 CFR chapter I, part 2, subpart B, shall be maintained appropriately (see 40 CFR part 2; 41 FR 36902, September 1, 1976; amended by 43 FR 39999, September 8, 1978; 43 FR 42251, September 28, 1978; 44 FR 17674, March 23, 1979).

Respondents/affected entities: The respondents/affected entities are the owners/operators of certain non-EGU industry sources in the following industry sectors: furnaces in Glass and Glass Product Manufacturing; boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; kilns in Cement and Cement Product Manufacturing; reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; and boilers in Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and combustors and incinerators in Solid Waste Combustors and Incinerators.

Respondent's obligation to respond: Voluntary and mandatory. (Sections 110(a) and 301(a) of the Clean Air Act.) All data that is recorded or reported by respondents is required by the final rule, titled ''Federal ''Good Neighbor Plan'' for the 2015 Ozone National Ambient Air Quality Standards.''

Estimated number of respondents: 3,328.

Frequency of response: The specific frequency for each information collection activity within the non-EGU ICR is shown at the end of the ICR document in Tables 1 through 18. In general, the frequency varies across the monitoring, recordkeeping, and reporting activities. Some recordkeeping such as work plan preparation is a one-time activity whereas pipeline engine maintenance recordkeeping is conducted quarterly. Reporting frequency is on an annual basis.

Total estimated burden: 11,481 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $3,823,000 (average per year); includes $2,400,000 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities subject to the requirements of this action are small businesses, which includes EGUs and non-EGUs and are described in more detail below. In 2026, the EPA identified a total of 29 small entities affected by the rule. Of these, 2 small entities may experience costs of greater than 1 percent of revenues. In 2026 for EGUs, the EPA identified 19 small entities. The EPA's decision to exclude units smaller than 25 MW capacity from the final rule, and exclusion of uncontrolled units smaller than 100 MW from backstop emissions rates significantly reduced the burden on small entities by reducing the number of affected small entity-owned units. Further, in 2026 for non-EGUs, there are ten small entities, and two small entities are estimated to have a cost-to-sales impact between 1.7 and 2.4 percent of their revenues.

The Agency has not determined that a significant number of small entities potentially affected by the rule will have compliance costs greater than 1 percent of annual revenues during the compliance period. The EPA has concluded that there will be no significant economic impact on a substantial number of small entities (No SISNOSE) for this rule overall. Details of this analysis are presented in Chapter 6 of the *RIA,* which is in the public docket.

D. Unfunded Mandates Reform Act (UMRA)

This action contains no unfunded Federal mandate for State, local, or Tribal governments as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action imposes no enforceable duty on any State, local, or Tribal government. This action contains a Federal mandate under UMRA, 2 U.S.C. 1531–1538, that may result in expenditures of $100 million or more in any one year for the private sector. Accordingly, the costs and benefits associated with this action are discussed in section VIII of this preamble and in the *RIA,* which is in the docket for this rule. Additional details are presented in the *RIA.* This action is not subject to the requirements of UMRA section 203 because it contains no regulatory requirements that might significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the National Government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This final action has tribal implications. However, it would neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law.

The EPA is finalizing a finding that interstate transport of ozone precursor emissions from 23 upwind states (Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin) is significantly contributing to downwind nonattainment or interfering with maintenance of the 2015 ozone NAAQS in other states. The EPA is promulgating FIP requirements to eliminate interstate transport of ozone precursors from these 23 states. Under CAA section 301(d)(4), the EPA is extending FIP requirements to apply in Indian country located within the upwind geography of the final rule, including Indian reservation lands and other areas of Indian country over which the EPA or a tribe has demonstrated that a tribe has jurisdiction. The EPA's determinations in this regard are described further in section III.C.2 of this document, *Application of Rule in Indian Country and Necessary or Appropriate Finding.* The EPA finds that all covered existing and new EGU and non-EGU sources that are located in the ''301(d) FIP'' areas within the geographic boundaries of the covered states, and which would be subject to this rule if located within areas subject to state CAA planning authority, should be included in this rule. To the EPA's knowledge, only one covered existing EGU or non-EGU source is located within the 301(d) FIP areas: the Bonanza Power Plant, an EGU source, located on the Uintah and Ouray Reservation, geographically located within the borders of Utah. This final action has tribal implication because of the extension of FIP requirements into Indian country and because, in general, tribes have a vested interest in how this final rule would affect air quality.

The EPA hosted an environmental justice webinar on October 26, 2021, that was attended by state regulatory authorities, environmental groups, federally recognized tribes, and small business stakeholders. The EPA issued tribal consultation letters addressed to 574 tribes in February 2022 after the proposed rule was signed. The EPA received no further requests to facilitate additional tribal consultation for the final rule.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive order. This action is not subject to Executive Order 13045 because it implements a previously promulgated health-based Federal standard. This action's health and risk assessments are contained in Chapter 5 and 6 of the *RIA.* The EPA believes that the ozone-related benefits, $PM_{2.5}$-related benefits, and CO_2- related benefits from this final rule will further improve children's health. Additionally, the ozone and $PM_{2.5}$ EJ exposure analyses in Chapter 7 of the *RIA* suggests that nationally, children (ages 0–17) will experience at least as great a reduction in ozone and $PM_{2.5}$ exposures as adults (ages 18–64) in 2023 and 2026 under all regulatory alternatives of this rulemaking.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The EPA has prepared a Statement of Energy Effects for the final regulatory control alternative as follows. The Agency estimates a 1 percent change in retail electricity prices on average across the contiguous U.S. in the 2025 run year, a 4 percent reduction (28 GWh) in coal-fired electricity generation, a 2 percent increase (21 GWh) in natural gas-fired electricity generation, and a 1 percent increase (8 GWh) in renewable electricity generation as a result of this final rule. The EPA projects that utility power sector delivered natural gas prices will change by less than 1 percent in 2025. Details of the estimated energy effects are presented in Chapter 4 of the *RIA,* which is in the public docket.

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations (people of color and/or indigenous peoples) and low-income populations.

The EPA believes that the human health or environmental conditions that exist prior to this action result in or have the potential to result in disproportionate and adverse human health or environmental effects on people of color, low-income populations and/or Indigenous peoples. The documentation for this decision is contained in section VII of this document, *Environmental Justice Analytical Considerations and Stakeholder Outreach and Engagement,* and in Chapter 7, *Environmental Justice Impacts* of the *RIA,* which is in the public document. Briefly, proximity demographic analyses found larger percentages of Hispanics, African Americans, people below the poverty level, people with less educational attainment, and people linguistically isolated are living within 5 km and 10 km of an affected EGU, compared to national averages. It also finds larger percentages of African Americans, people below the poverty level, and with less educational attainment living within 5 km and 10 km of an affected non-EGU facility. Considering the known limitations of proximity analyses, including the inability to assess policy-specific impacts, we also performed analysis of baseline EJ ozone and $PM_{2.5}$ exposures. Baseline ozone and $PM_{2.5}$ exposure analyses show that certain populations, such as Hispanics, Asians, those linguistically isolated, those less educated, and children may experience disproportionately higher ozone and $PM_{2.5}$ exposures as compared to the national average. American Indians may also experience disproportionately higher ozone concentrations than the reference group.

The EPA believes that this action is not likely to change existing disproportionate and adverse effects on people of color, low-income populations and/or Indigenous peoples. Specifically, we do not find evidence that potential EJ concerns related to ozone or $PM_{2.5}$ exposures will be meaningfully exacerbated or mitigated in the regulatory alternatives under consideration as compared to the baseline. We infer that baseline disparities in the ozone and $PM_{2.5}$ concentration burdens are likely to persist after implementation of the regulatory action or alternatives under consideration, due to similar modeled concentration reductions across population demographics. Importantly, the action described in this rule is expected to lower ozone and $PM_{2.5}$ in many areas, including in ozone nonattainment areas, and thus mitigate some pre-existing health risks across all populations evaluated.

The EPA additionally identified and addressed environmental justice concerns by providing the public, including those communities disproportionately impacted by the burdens of pollution, opportunities for meaningful engagement with the EPA on this action through outreach activities conducted by the Agency. The information supporting this Executive order review is contained in section VII of this document.

K. Congressional Review Act

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. Because this action falls within the definition provided by 5 U.S.C. 804(2), the rule's effective date is consistent with 5 U.S.C. 801(a)(3).

L. Determinations Under CAA Section 307(b)(1) and (d)

Section 307(b)(1) of the CAA governs judicial review of final actions by the EPA. This section provides, in part, that petitions for review must be filed in the D.C. Circuit: (i) when the agency action consists of ''nationally applicable regulations promulgated, or final actions taken, by the Administrator,'' or (ii) when such action is locally or regionally applicable, but ''such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination.'' For locally or regionally applicable final actions, the CAA reserves to the EPA complete discretion whether to invoke the exception in (ii).[434]

[434] In deciding whether to invoke the exception by making and publishing a finding that an action is based on a determination of nationwide scope or effect, the Administrator takes into account a number of policy considerations, including his judgment balancing the benefit of obtaining the D.C. Continued

This rulemaking is ''nationally applicable'' within the meaning of CAA section 307(b)(1). In this final action, the EPA is applying a uniform legal interpretation and common, nationwide analytical methods with respect to the requirements of CAA section 110(a)(2)(D)(i)(I) concerning interstate transport of pollution (*i.e.,* ''good neighbor'' requirements) to promulgate FIPs that satisfy these requirements for the 2015 ozone NAAQS. Based on these analyses, the EPA is promulgating FIPs for 23 states located across a wide geographic area in eight of the ten EPA regions and ten Federal judicial circuits. Given that this action addresses implementation of the good neighbor requirements of CAA section 110(a)(2)(D)(i)(I) in a large number of states located across the country, and given the interdependent nature of interstate pollution transport and the common core of knowledge and analysis involved in promulgating these FIPs, this is a ''nationally applicable'' action within the meaning of CAA section 307(b)(1).

In the alternative, to the extent a court finds this action to be locally or regionally applicable, the Administrator is exercising the complete discretion afforded to him under the CAA to make and publish a finding that this action is based on a determination of ''nationwide scope or effect'' within the meaning of CAA section 307(b)(1). In this final action, the EPA is interpreting and applying section 110(a)(2)(d)(i)(I) of the CAA for the 2015 ozone NAAQS based on a common core of nationwide policy judgments and technical analysis concerning the interstate transport of pollutants throughout the continental U.S. In particular, the EPA is applying here the same, nationally consistent 4-step framework for assessing good neighbor obligations for the 2015 ozone NAAQS that it has applied in other nationally applicable rulemakings, such as CSAPR, the CSAPR Update, and the Revised CSAPR Update. The EPA is relying on the results from nationwide photochemical grid modeling using a 2016 base year and 2023 projection year as the primary basis for its assessment of air quality conditions and pollution contribution levels at Step 1 and Step 2 of that 4-step framework and applying a nationally uniform approach to the identification of nonattainment and maintenance receptors across the entire geographic area covered by this final rule.[435]

The Administrator finds that this is a matter on which national uniformity in judicial resolution of any petitions for review is desirable, to take advantage of the D.C. Circuit's administrative law expertise, and to facilitate the orderly development of the basic law under the Act. The Administrator also finds that consolidated review of this action in the D.C. Circuit will avoid piecemeal litigation in the regional circuits, further judicial economy, and eliminate the risk of inconsistent results for different states, and that a nationally consistent approach to the CAA's mandate concerning interstate transport of ozone pollution constitutes the best use of agency resources. The EPA's responses to comments on the appropriate venue for petitions for review are contained in section 1.10 of the *RTC* document.

For these reasons, this final action is nationally applicable or, alternatively, the Administrator is exercising the complete discretion afforded to him by the CAA and finds that this final action is based on a determination of nationwide scope or effect for purposes of CAA section 307(b)(1) and is publishing that finding in the **Federal Register**. Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the District of Columbia Circuit by August 4, 2023.

This action is subject to the provisions of section 307(d). CAA section 307(d)(1)(B) provides that section 307(d) applies to, among other things, ''the promulgation or revision of an implementation plan by the Administrator under [CAA section 110(c)].'' 42 U.S.C. 7407(d)(1)(B). This action, among other things, promulgates new Federal implementation plans pursuant to the authority of section 110(c). To the extent any portion of this final action is not expressly identified under section 307(d)(1)(B), the Administrator determines that the provisions of section 307(d) apply to such final action. *See* CAA section 307(d)(1)(V) (the provisions of section 307(d) apply to ''such other actions as the Administrator may determine'').

Circuit's authoritative centralized review versus allowing development of the issue in other contexts and the best use of agency resources.

[435] In the report on the 1977 Amendments that revised section 307(b)(1) of the CAA, Congress noted that the Administrator's determination that the ''nationwide scope or effect'' exception applies would be appropriate for any action that has a scope or effect beyond a single judicial circuit. *See* H.R. Rep. No. 95–294 at 323, 324, reprinted in 1977 U.S.C.C.A.N. 1402–03.

List of Subjects

40 CFR Part 52

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen oxides, Ozone, Particulate matter, Sulfur dioxide.

40 CFR Part 75

Environmental protection, Administrative practice and procedure, Air pollution control, Continuous emissions monitoring, Electric power plants, Nitrogen oxides, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Part 78

Environmental protection, Administrative practice and procedure, Air pollution control, Electric power plants, Nitrogen oxides, Ozone, Particulate matter, Sulfur dioxide.

40 CFR Part 97

Environmental protection, Administrative practice and procedure, Air pollution control, Electric power plants, Nitrogen oxides, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxide.

Michael S. Regan,

Administrator.

For the reasons stated in the preamble, parts 52, 75, 78, and 97 of title 40 of the Code of Federal Regulations are amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 2. Amend § 52.38 by:

■ a. In paragraph (a)(1), removing ''(NO_X), except'' and adding in its place ''(NO_X) for sources meeting the applicability criteria set forth in subpart AAAAA, except'';

■ b. In paragraph (a)(3) introductory text:

■ i. Removing ''(a)(2)(i) or (ii)'' and adding in its place ''(a)(2)''; and

■ ii. Removing ''the State and'' and adding in its place ''sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for'';

■ c. In paragraph (a)(3)(i), removing ''State and'' and adding in its place

''State and areas of Indian country within the borders of the State subject to the State's SIP authority and that'';
■ d. In paragraph (a)(4) introductory text, removing ''for the State's sources, and'' and adding in its place ''with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, and'';
■ e. Revising table 1 to paragraph (a)(4)(i)(B);
■ f. In paragraph (a)(4)(ii), removing ''deadlines for submission of allocations or auction results under paragraphs (a)(4)(i)(B) and (C)'' and adding in its place ''deadline for submission of allocations or auction results under paragraph (a)(4)(i)(B)'';
■ g. In paragraph (a)(5) introductory text, removing ''State (but not sources in any Indian country within the borders of the State), regulations'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations'';
■ h. Revising table 2 to paragraph (a)(5)(i)(B);
■ i. In paragraph (a)(5)(iv), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority'';
■ j. In paragraph (a)(5)(v), removing ''Indian country within the borders of the State, the'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority, the'';
■ k. In paragraph (a)(5)(vi), removing ''deadlines for submission of allocations or auction results under paragraphs (a)(5)(i)(B) and (C)'' and adding in its place ''deadline for submission of allocations or auction results under paragraph (a)(5)(i)(B)'';
■ l. Revising paragraphs (a)(6) and (a)(7)(ii);
■ m. Adding paragraph (a)(7)(iii);
■ n. In paragraphs (a)(8)(i) and (ii), removing ''the State and'' and adding in its place ''sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for'';
■ o. In paragraph (a)(8)(iii), removing ''State (but not sources in any Indian country within the borders of the State):'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority:'';
■ p. In paragraph (b)(1), removing ''year), except'' and adding in its place ''year) for sources meeting the applicability criteria set forth in subparts BBBBB, EEEEE, and GGGGG, except'';
■ q. Redesignating paragraphs (b)(2)(i) and (ii) as paragraphs (b)(2)(i)(A) and (B), respectively, paragraphs (b)(2)(iii) and (iv) as paragraphs (b)(2)(ii)(A) and (B), respectively, and paragraph (b)(2)(v) as paragraph (b)(2)(iii)(A);
■ r. In newly redesignated paragraph (b)(2)(ii)(A), removing ''Alabama, Arkansas, Iowa, Kansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin.'' and adding in its place ''Iowa, Kansas, and Tennessee.'';
■ s. Adding paragraphs (b)(2)(ii)(C) and (b)(2)(iii)(B) and (C);
■ t. In paragraph (b)(3) introductory text:
■ i. Removing ''or (ii)''; and
■ ii. Removing ''the State and'' and adding in its place ''sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for'';
■ u. In paragraph (b)(3)(i), removing ''State and'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority and that'';
■ v. Revising paragraph (b)(4) introductory text;
■ w. Removing and reserving paragraph (b)(4)(i);
■ x. Revising table 3 to paragraph (b)(4)(ii)(B) and paragraphs (b)(4)(iii) and (b)(5) introductory text;
■ y. Removing and reserving paragraph (b)(5)(i);
■ z. Revising table 4 to paragraph (b)(5)(ii)(B);
■ aa. In paragraph (b)(5)(v), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority'';
■ bb. In paragraph (b)(5)(vi), removing ''Indian country within the borders of the State, the'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority, the'';
■ cc. Revising paragraphs (b)(5)(vii), (b)(7) introductory text, (b)(7)(i), and (b)(8) introductory text;
■ dd. Removing and reserving paragraphs (b)(8)(i) and (ii);
■ ee. Revising paragraph (b)(8)(iii)(A), table 5 to paragraph (b)(8)(iii)(B), and paragraphs (b)(8)(iv) and (b)(9) introductory text;
■ ff. Removing and reserving paragraphs (b)(9)(i) and (ii);
■ gg. Revising paragraph (b)(9)(iii)(A) and table 6 to paragraph (b)(9)(iii)(B);
■ hh. In paragraph (b)(9)(vi), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority'';
■ ii. Revising paragraphs (b)(9)(vii) and (viii), (b)(10) introductory text, (b)(10)(i) and (ii), (b)(10)(v)(A) and (B), and (b)(11) introductory text;
■ jj. Removing and reserving paragraphs (b)(11)(i) and (ii);
■ kk. In paragraph (b)(11)(iii) introductory text, removing ''§§ 97.1011(a) and (b)(1) and 97.1012(a)'' and adding in its place ''§ 97.1011(a)(1)'';
■ ll. Revising paragraph (b)(11)(iii)(A);
mm. In paragraph (b)(11)(iii)(B):
■ i. Removing ''§ 97.1011(a)'' and adding in its place ''§ 97.1011(a)(1)''; and
■ ii. Adding ''and'' after the semicolon;
■ nn. Removing and reserving paragraph (b)(11)(iii)(C);
■ oo. Revising paragraphs (b)(11)(iii)(D), (b)(11)(iv), and (b)(12) introductory text;
■ pp. Removing and reserving paragraphs (b)(12)(i) and (ii);
■ qq. In paragraph (b)(12)(iii) introductory text, removing ''§§ 97.1011(a) and (b)(1) and 97.1012(a)'' and adding in its place ''§ 97.1011(a)(1)'';
■ rr. Revising paragraph (b)(12)(iii)(A);
■ ss. In paragraph (b)(12)(iii)(B):
■ i. Removing ''§ 97.1011(a)'' and adding in its place ''§ 97.1011(a)(1)''; and
■ ii. Adding ''and'' after the semicolon;
■ tt. Removing and reserving paragraph (b)(12)(iii)(C);
■ uu. Revising paragraphs (b)(12)(iii)(D), (b)(12)(vi) through (viii), (b)(13) introductory text, and (b)(13)(i);
■ vv. In paragraph (b)(13)(ii), removing ''regulations, including any sources made subject to such regulations pursuant to paragraph (b)(9)(ii) or (b)(12)(ii) of this section, the'' and adding in its place ''regulations the'';
■ ww. In paragraph (b)(14)(i)(F), removing ''§ 97.825(b)'' and adding in its place ''§§ 97.806(c)(2) and (3) and 97.825(b)'';
■ xx. In paragraph (b)(14)(i)(G), removing ''§ 97.826(e)'' and adding in its place ''§ 97.826(f)'';
■ yy. Revising paragraphs (b)(14)(ii) and (iii);
■ zz. In paragraph (b)(15)(i), removing ''the State and'' and adding in its place ''sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for'';
■ aaa. Revising paragraph (b)(15)(ii);
■ bbb. In paragraph (b)(15)(iii), removing ''State (but not sources in any Indian country within the borders of the State):'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority:'';

■ ccc. In paragraph (b)(16)(i)(A), removing ''the State and'' and adding in its place ''sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for'';

■ ddd. Revising paragraphs (b)(16)(i)(B) and (C);

■ eee. Redesignating paragraph (b)(16)(ii) as paragraph (b)(16)(ii)(A), and, in newly redesignated paragraph (b)(16)(ii)(A), removing ''(b)(2)(iv)'' and adding in its place ''(b)(2)(ii)(B)'';

■ fff. Adding paragraph (b)(16)(ii)(B); and

■ ggg. Revising paragraphs (b)(17)(i) through (iii).

The revisions and additions read as follows:

§ 52.38 What are the requirements of the Federal Implementation Plans (FIPs) for the Cross-State Air Pollution Rule (CSAPR) relating to emissions of nitrogen oxides?

(a) * * *

(4) * * *

(i) * * *

(B) * * *

TABLE 1 TO PARAGRAPH (a)(4)(i)(B)

Year of the control period for which CSAPR NO_X Annual allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the administrator
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(5) * * *

(i) * * *

(B) * * *

TABLE 2 TO PARAGRAPH (a)(5)(i)(B)

Year of the control period for which CSAPR NO_X Annual allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the administrator
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(6) *Withdrawal of CSAPR FIP provisions relating to NO_X annual emissions.* Except as provided in paragraph (a)(7) of this section, following promulgation of an approval by the Administrator of a State's SIP revision as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (a)(1), (a)(2)(i), and (a)(3) and (4) of this section for sources in the State and Indian country within the borders of the State subject to the State's SIP authority, the provisions of paragraph (a)(2)(i) of this section will no longer apply to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, unless the Administrator's approval of the SIP revision is partial or conditional, and will continue to apply to sources in areas of Indian country within the borders of the State not subject to the State's SIP authority, provided that if the CSAPR Federal Implementation Plan was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

(7) * * *

(ii) Notwithstanding the provisions of paragraph (a)(6) of this section, if, at the time of any approval of a State's SIP revision under this section, the Administrator has already started recording any allocations of CSAPR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart AAAAA authorizing the Administrator to complete the allocation and recordation of such allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(iii) Notwithstanding any discontinuation pursuant to paragraph (a)(2)(ii) or (a)(6) of this section of the applicability of subpart AAAAA of part 97 of this chapter to the sources in a State and areas of Indian country within the borders of the State subject to the State's SIP authority with regard to emissions occurring in any control period, the following provisions shall continue to apply with regard to all CSAPR NO_X Annual allowances at any time allocated for any control period to any source or other entity in the State and areas of Indian country within the borders of the State subject to the State's SIP authority and shall apply to all entities, wherever located, that at any time held or hold such allowances:

(A) The provisions of § 97.426(c) of this chapter (concerning the transfer of CSAPR NO_X Annual allowances between certain Allowance Management System accounts under common control).

(B) [Reserved]

* * * * *

(b) * * *

(2) * * *

(ii) * * *

(C) The provisions of subpart EEEEE of part 97 of this chapter apply to sources in each of the following States and Indian country located within the borders of such States with regard to emissions occurring in 2017 through 2022 only, except as provided in paragraph (b)(14)(iii) of this section: Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin.

(iii) * * *

(B) The provisions of subpart GGGGG of part 97 of this chapter apply to sources in each of the following States and Indian country located within the borders of such States with regard to emissions occurring in 2023 and each subsequent year: Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin.

(C) The provisions of subpart GGGGG of part 97 of this chapter apply to sources in each of the following States and Indian country located within the borders of such States with regard to emissions occurring on and after August 4, 2023, and in each subsequent year: Minnesota, Nevada, and Utah.

* * * * *

(4) *Abbreviated SIP revisions replacing certain provisions of the Federal CSAPR NO_X Ozone Season Group 1 Trading Program.* A State listed in paragraph (b)(2)(i)(A) of this section may adopt and include in a SIP revision, and the Administrator will approve, regulations replacing specified provisions of subpart BBBBB of part 97 of this chapter with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, and not substantively replacing any other provisions, as follows:

* * * * *

(ii) * * *

(B) * * *

TABLE 3 TO PARAGRAPH (b)(4)(ii)(B)

Year of the control period for which CSAPR NO_X Ozone Season Group 1 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the administrator
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(iii) Provided that the State must submit a complete SIP revision meeting the requirements of paragraph (b)(4)(ii) of this section by December 1 of the year before the year of the deadline for submission of allocations or auction results under paragraph (b)(4)(ii)(B) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (b)(4)(ii) of this section.

(5) *Full SIP revisions adopting State CSAPR NO_X Ozone Season Group 1 Trading Programs.* A State listed in paragraph (b)(2)(i)(A) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting the deficiency in the SIP that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(i), and (b)(3) and (4) of this section with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations that are substantively identical to the provisions of the CSAPR NO_X Ozone Season Group 1 Trading Program set forth in §§ 97.502 through 97.535 of this chapter, except that the SIP revision:

* * * * *

(ii) * * *

(B) * * *

TABLE 4 TO PARAGRAPH (b)(5)(ii)(B)

Year of the control period for which CSAPR NO_X Ozone Season group 1 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the administrator
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(vii) Provided that the State must submit a complete SIP revision meeting the requirements of paragraphs (b)(5)(ii) through (v) of this section by December 1 of the year before the year of the deadline for submission of allocations or auction results under paragraph (b)(5)(ii)(B) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (b)(5)(ii) of this section.

* * * * *

(7) *State-determined allocations of CSAPR NO_X Ozone Season Group 2 allowances for 2018.* A State listed in paragraph (b)(2)(ii) of this section may adopt and include in a SIP revision, and the Administrator will approve, as CSAPR NO_X Ozone Season Group 2 allowance allocation provisions replacing the provisions in § 97.811(a) of this chapter with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for the control period in 2018, a list of CSAPR NO_X Ozone Season Group 2 units and the amount of CSAPR NO_X Ozone Season Group 2 allowances allocated to each unit on such list, provided that the list of units and allocations meets the following requirements:

(i) All of the units on the list must be units that are in the State and areas of Indian country within the borders of the State subject to the State's SIP authority and that commenced commercial operation before January 1, 2015;

* * * * *

(8) *Abbreviated SIP revisions replacing certain provisions of the Federal CSAPR NO_X Ozone Season Group 2 Trading Program.* A State listed in paragraph (b)(2)(ii) of this section may adopt and include in a SIP revision, and the Administrator will approve, regulations replacing specified provisions of subpart EEEEE of part 97 of this chapter with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, and not substantively replacing any other provisions, as follows:

* * * * *

(iii) * * *

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of CSAPR NO_X Ozone Season Group 2 allowances for any such control period not exceeding the amount, under §§ 97.810(a) and 97.821 of this chapter for the State and such control period, of the CSAPR NO_X Ozone Season Group 2 trading budget minus the sum of the Indian country new unit set-aside and the amount of any CSAPR NO_X Ozone Season Group 2 allowances already allocated and recorded by the Administrator;

(B) * * *

TABLE 5 TO PARAGRAPH (b)(8)(iii)(B)

Year of the control period for which CSAPR NO_X Ozone Season Group 2 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the administrator
2019 or 2020	June 1, 2018.
2021 or 2022	June 1, 2019.
2023 or 2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(iv) Provided that the State must submit a complete SIP revision meeting the requirements of paragraph (b)(8)(iii) of this section by December 1 of the year before the year of the deadline for submission of allocations or auction results under paragraph (b)(8)(iii)(B) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (b)(8)(iii) of this section.

(9) *Full SIP revisions adopting State CSAPR NO_X Ozone Season Group 2 Trading Programs.* A State listed in paragraph (b)(2)(ii) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting the deficiency in the SIP that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(ii), and (b)(7) and (8) of this section with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations that are substantively identical to the provisions of the CSAPR NO_X Ozone Season Group 2 Trading Program set forth in §§ 97.802 through 97.835 of this chapter, except that the SIP revision:

* * * * *

(iii) * * *

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of CSAPR NO_X Ozone Season Group 2 allowances for any such control period not exceeding the amount, under §§ 97.810(a) and 97.821 of this chapter for the State and such control period, of the CSAPR NO_X Ozone Season Group 2 trading budget minus the sum of the Indian country new unit set-aside and the amount of any CSAPR NO_X Ozone Season Group 2 allowances already allocated and recorded by the Administrator;

(B) * * *

TABLE 6 TO PARAGRAPH (b)(9)(iii)(B)

Year of the control period for which CSAPR NO_X Ozone Season Group 2 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the administrator
2019 or 2020	June 1, 2018.
2021 or 2022	June 1, 2019.
2023 or 2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(vii) Provided that, if and when any covered unit is located in areas of Indian country within the borders of the State not subject to the State's SIP authority, the Administrator may modify his or her approval of the SIP revision to exclude the provisions in §§ 97.802 (definitions of ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share''), 97.806(c)(2), and 97.825 of this chapter and the portions of other provisions of subpart EEEEE of part 97 of this chapter referencing §§ 97.802, 97.806(c)(2), and 97.825 and may modify any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision to include these provisions; and

(viii) Provided that the State must submit a complete SIP revision meeting the requirements of paragraphs (b)(9)(iii) through (vi) of this section by December 1 of the year before the year of the deadline for submission of allocations or auction results under paragraph (b)(9)(iii)(B) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (b)(9)(iii) of this section.

(10) *State-determined allocations of CSAPR NO_X Ozone Season Group 3 allowances for 2024.* A State listed in paragraph (b)(2)(iii) of this section may adopt and include in a SIP revision, and the Administrator will approve, as CSAPR NO_X Ozone Season Group 3 allowance allocation provisions replacing the provisions in § 97.1011(a)(1) of this chapter with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for the control period in 2024, a list of CSAPR NO_X Ozone Season Group 3 units and the amount of CSAPR NO_X Ozone Season Group 3 allowances

allocated to each unit on such list, provided that the list of units and allocations meets the following requirements:

(i) All of the units on the list must be units that are in the State and areas of Indian country within the borders of the State subject to the State's SIP authority and that commenced commercial operation before January 1, 2021;

(ii) The total amount of CSAPR NO_X Ozone Season Group 3 allowance allocations on the list must not exceed the amount, under § 97.1010 of this chapter for the State and the control period in 2024, of the CSAPR NO_X Ozone Season Group 3 trading budget minus the sum of the Indian country existing unit set-aside and the new unit set-aside;

* * * * *

(v) * * *

(A) By August 4, 2023, the State must notify the Administrator electronically in a format specified by the Administrator of the State's intent to submit to the Administrator a complete SIP revision meeting the requirements of paragraphs (b)(10)(i) through (iv) of this section by September 1, 2023; and

(B) The State must submit to the Administrator a complete SIP revision described in paragraph (b)(10)(v)(A) of this section by September 1, 2023.

(11) *Abbreviated SIP revisions replacing certain provisions of the Federal CSAPR NO_X Ozone Season Group 3 Trading Program.* A State listed in paragraph (b)(2)(iii) of this section may adopt and include in a SIP revision, and the Administrator will approve, regulations replacing specified provisions of subpart GGGGG of part 97 of this chapter with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, and not substantively replacing any other provisions, as follows:

* * * * *

(iii) * * *

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of CSAPR NO_X Ozone Season Group 3 allowances for any such control period not exceeding the amount, under §§ 97.1010 and 97.1021 of this chapter for the State and such control period, of the CSAPR NO_X Ozone Season Group 3 trading budget minus the sum of the Indian country existing unit set-aside, the new unit set-aside, and the amount of any CSAPR NO_X Ozone Season Group 3 allowances already allocated and recorded by the Administrator;

* * * * *

(D) Does not provide for any change, after the submission deadlines in paragraph (b)(11)(iii)(B) of this section, in the allocations submitted to the Administrator by such deadlines and does not provide for any change in any allocation determined and recorded by the Administrator under subpart GGGGG of part 97 of this chapter or § 97.526(d) or § 97.826(d) or (e) of this chapter; and

(iv) Provided that the State must submit a complete SIP revision meeting the requirements of paragraph (b)(11)(iii) of this section by December 1 of the year before the year of the deadline for submission of allocations or auction results under paragraph (b)(11)(iii)(B) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (b)(11)(iii) of this section.

(12) *Full SIP revisions adopting State CSAPR NO_X Ozone Season Group 3 Trading Programs.* A State listed in paragraph (b)(2)(iii) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting the deficiency in the SIP that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(iii), and (b)(10) and (11) of this section with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations that are substantively identical to the provisions of the CSAPR NO_X Ozone Season Group 3 Trading Program set forth in §§ 97.1002 through 97.1035 of this chapter, except that the SIP revision:

* * * * *

(iii) * * *

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of CSAPR NO_X Ozone Season Group 3 allowances for any such control period not exceeding the amount, under §§ 97.1010 and 97.1021 of this chapter for the State and such control period, of the CSAPR NO_X Ozone Season Group 3 trading budget minus the sum of the Indian country existing unit set-aside, the new unit set-aside, and the amount of any CSAPR NO_X Ozone Season Group 3 allowances already allocated and recorded by the Administrator;

* * * * *

(D) Does not provide for any change, after the submission deadlines in paragraph (b)(12)(iii)(B) of this section, in the allocations submitted to the Administrator by such deadlines and does not provide for any change in any allocation determined and recorded by the Administrator under subpart GGGGG of part 97 of this chapter or § 97.526(d) or § 97.826(d) or (e) of this chapter;

* * * * *

(vi) Must not include any of the requirements imposed on any unit in areas of Indian country within the borders of the State not subject to the State's SIP authority in the provisions in §§ 97.1002 through 97.1035 of this chapter and must not include the provisions in §§ 97.1011(a)(2), 97.1012, and 97.1021(g) through (j) of this chapter, all of which provisions will continue to apply under any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision;

(vii) Provided that, if before the Administrator's approval of the SIP revision any covered unit is located in areas of Indian country within the borders of the State not subject to the State's SIP authority before the Administrator's approval of the SIP revision, the SIP revision must exclude the provisions in §§ 97.1002 (definitions of ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share''), 97.1006(c)(2), and 97.1025 of this chapter and the portions of other provisions of subpart GGGGG of part 97 of this chapter referencing §§ 97.1002, 97.1006(c)(2), and 97.1025, and further provided that, if and when after the Administrator's approval of the SIP revision any covered unit is located in areas of Indian country within the borders of the State not subject to the State's SIP authority, the Administrator may modify his or her approval of the SIP revision to exclude these provisions and may modify any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision to include these provisions; and

(viii) Provided that the State must submit a complete SIP revision meeting the requirements of paragraphs (b)(12)(iii) through (vi) of this section by December 1 of the year before the year of the deadline for submission of allocations or auction results under paragraph (b)(12)(iii)(B) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (b)(12)(iii) of this section.

(13) *Withdrawal of CSAPR FIP provisions relating to NO_X ozone season emissions; satisfaction of NO_X SIP Call requirements.* Following promulgation of an approval by the Administrator of a State's SIP revision as correcting the SIP's deficiency that is the basis for the

CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(i), and (b)(3) and (4) of this section, paragraphs (b)(1), (b)(2)(ii), and (b)(7) and (8) of this section, or paragraphs (b)(1), (b)(2)(iii), and (b)(10) and (11) of this section for sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority—

(i) Except as provided in paragraph (b)(14) of this section, the provisions of paragraph (b)(2)(i), (ii), or (iii) of this section, as applicable, will no longer apply to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, unless the Administrator's approval of the SIP revision is partial or conditional, and will continue to apply to sources in areas of Indian country within the borders of the State not subject to the State's SIP authority, provided that if the CSAPR Federal Implementation Plan was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision; and

* * * * *

(14) * * *

(ii) Notwithstanding the provisions of paragraph (b)(13)(i) of this section, if, at the time of any approval of a State's SIP revision under this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 1 allowances under subpart BBBBB of part 97 of this chapter, or allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter, or allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter, to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of such subpart authorizing the Administrator to complete the allocation and recordation of such allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(iii) Notwithstanding any discontinuation pursuant to paragraph (b)(2)(i)(B), (b)(2)(ii)(B) or (C), or (b)(13)(i) of this section of the applicability of subpart BBBBB or EEEEE of part 97 of this chapter to the sources in a State and areas of Indian country within the borders of the State subject to the State's SIP authority with regard to emissions occurring in any control period, the following provisions shall continue to apply with regard to all CSAPR NO_X Ozone Season Group 1 allowances and CSAPR NO_X Ozone Season Group 2 allowances at any time allocated for any control period to any source or other entity in the State and areas of Indian country within the borders of the State subject to the State's SIP authority and shall apply to all entities, wherever located, that at any time held or hold such allowances:

(A) The provisions of §§ 97.526(c) and 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 1 allowances and CSAPR NO_X Ozone Season Group 2 allowances between certain Allowance Management System accounts under common control);

(B) The provisions of §§ 97.526(d) and 97.826(d) and (e) of this chapter (concerning the conversion of unused CSAPR NO_X Ozone Season Group 1 allowances allocated for specified control periods to different amounts of CSAPR NO_X Ozone Season Group 2 allowances or CSAPR NO_X Ozone Season Group 3 allowances and the conversion of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for specified control periods to different amounts of CSAPR NO_X Ozone Season Group 3 allowances); and

(C) The provisions of § 97.811(d) and (e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all CSAPR NO_X Ozone Season Group 2 allowances allocated for specified control periods and recorded in specified Allowance Management System accounts).

(15) * * *

(ii) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(4) of this section as replacing the CSAPR NO_X Ozone Season Group 1 allowance allocation provisions in §§ 97.511(a) and (b)(1) and 97.512(a) of this chapter with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for the control period in 2017 or any subsequent year: [none].

* * * * *

(16) * * *

(i) * * *

(B) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(8) of this section as replacing the CSAPR NO_X Ozone Season Group 2 allowance allocation provisions in §§ 97.811(a) and (b)(1) and 97.812(a) of this chapter with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for the control period in 2019 or any subsequent year: New York.

(C) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(9) of this section as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(ii), and (b)(7) and (8) of this section with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority: Alabama, Indiana, and Missouri.

(ii) * * *

(B) Notwithstanding any provision of subpart EEEEE of part 97 of this chapter or any State's SIP, with regard to any State listed in paragraph (b)(2)(ii)(C) of this section and any control period that begins after December 31, 2022, the Administrator will not carry out any of the functions set forth for the Administrator in subpart EEEEE of part 97 of this chapter, except §§ 97.811(e) and 97.826(c) and (e) of this chapter, or in any emissions trading program provisions in a State's SIP approved under paragraph (b)(8) or (9) of this section.

(17) * * *

(i) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(10) of this section as replacing the CSAPR NO_X Ozone Season Group 3 allowance allocation provisions in § 97.1011(a)(1) of this chapter with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for the control period in 2024: [none].

(ii) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(11) of this section as replacing the CSAPR NO_X Ozone Season Group 3 allowance allocation provisions in § 97.1011(a)(1) of this chapter with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for the control period in 2025 or any subsequent year: [none].

(iii) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(12) of this section as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(iii), and (b)(10) and (11) of this section with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority: [none].

■ 3. Amend § 52.39 by:

■ a. In paragraph (a), removing ''(SO_2), except'' and adding in its place ''(SO_2) for sources meeting the applicability criteria set forth in subparts CCCCC and DDDDD, except'';

■ b. In paragraph (d) introductory text, removing ''the State and'' and adding in its place ''sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for'';

■ c. In paragraph (d)(1), removing ''State and'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority and that'';

■ d. In paragraph (e) introductory text, removing ''for the State's sources, and'' and adding in its place ''with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, and'';

■ e. Revising table 1 to paragraph (e)(1)(ii);

■ f. In paragraph (e)(2), removing ''deadlines for submission of allocations or auction results under paragraphs (e)(1)(ii) and (iii)'' and adding in its place ''deadline for submission of allocations or auction results under paragraph (e)(1)(ii)'';

■ g. In paragraph (f) introductory text, removing ''State (but not sources in any Indian country within the borders of the State), regulations'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations'';

■ h. Revising table 2 to paragraph (f)(1)(ii);

■ i. In paragraph (f)(4), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority'';

■ j. In paragraph (f)(5), removing ''Indian country within the borders of the State, the'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority, the'';

■ k. In paragraph (f)(6), removing ''deadlines for submission of allocations or auction results under paragraphs (f)(1)(ii) and (iii)'' and adding in its place ''deadline for submission of allocations or auction results under paragraph (f)(1)(ii)'';

■ l. In paragraph (g) introductory text:

■ i. Removing ''(c)(1) or (2)'' and adding in its place ''(c)''; and

■ ii. Removing ''the State and'' and adding in its place ''sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for'';

■ m. In paragraph (g)(1), removing ''State and'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority and that'';

■ n. In paragraph (h) introductory text, removing ''for the State's sources, and'' and adding in its place ''with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, and'';

■ o. Revising table 3 to paragraph (h)(1)(ii);

■ p. In paragraph (h)(2), removing ''deadlines for submission of allocations or auction results under paragraphs (h)(1)(ii) and (iii)'' and adding in its place ''deadline for submission of allocations or auction results under paragraph (h)(1)(ii)'';

■ q. In paragraph (i) introductory text, removing ''State (but not sources in any Indian country within the borders of the State), regulations'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations'';

■ r. Revising table 4 to paragraph (i)(1)(ii);

■ s. In paragraph (i)(4), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority'';

■ t. In paragraph (i)(5), removing ''Indian country within the borders of the State, the'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority, the'';

■ u. In paragraph (i)(6), removing ''deadlines for submission of allocations or auction results under paragraphs (i)(1)(ii) and (iii)'' and adding in its place ''deadline for submission of allocations or auction results under paragraph (i)(1)(ii)'';

■ v. Revising paragraphs (j) and (k)(2);

■ w. Adding paragraph (k)(3);

■ x. In paragraphs (l)(1) and (2), removing ''the State and'' and adding in its place ''sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for'';

■ y. In paragraph (l)(3), removing ''State (but not sources in any Indian country within the borders of the State):'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority:''.

■ z. In paragraphs (m)(1) and (2), removing ''the State and'' and adding in its place ''sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for''; and

■ aa. In paragraph (m)(3), removing ''State (but not sources in any Indian country within the borders of the State):'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority:''.

The revisions and addition read as follows:

§ 52.39 What are the requirements of the Federal Implementation Plans (FIPs) for the Cross-State Air Pollution Rule (CSAPR) relating to emissions of sulfur dioxide?

* * * * *

(e) * * *

(1) * * *

(ii) * * *

TABLE 1 TO PARAGRAPH (e)(1)(ii)

Year of the control period for which CSAPR SO_2 group 1 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the administrator
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(f) * * *

(1) * * *

(ii) * * *

TABLE 2 TO PARAGRAPH (f)(1)(ii)

Year of the control period for which CSAPR SO_2 group 1 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the administrator
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(h) * * *

(1) * * *

(ii) * * *

TABLE 3 TO PARAGRAPH (h)(1)(ii)

Year of the control period for which CSAPR SO_2 group 2 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the administrator
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(i) * * *

(1) * * *

(ii) * * *

TABLE 4 TO PARAGRAPH (i)(1)(ii)

Year of the control period for which CSAPR SO_2 group 2 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the administrator
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(j) *Withdrawal of CSAPR FIP provisions relating to SO_2 emissions.* Except as provided in paragraph (k) of this section, following promulgation of an approval by the Administrator of a State's SIP revision as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (a), (b), (d), and (e) of this section or paragraphs (a), (c)(1), (g), and (h) of this section for sources in the State and Indian country within the borders of the State subject to the State's SIP authority, the provisions of paragraph (b) or (c)(1) of this section, as applicable, will no longer apply to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, unless the Administrator's approval of the SIP revision is partial or conditional, and will continue to apply to sources in areas of Indian country within the borders of the State not subject to the State's SIP authority, provided that if the CSAPR Federal Implementation Plan was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

(k) * * *

(2) Notwithstanding the provisions of paragraph (j) of this section, if, at the time of any approval of a State's SIP revision under this section, the Administrator has already started recording any allocations of CSAPR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter, or allocations of CSAPR SO_2 Group 2 allowances under subpart DDDDD of part 97 of this chapter, to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of such subpart authorizing the Administrator to complete the allocation and recordation of such allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(3) Notwithstanding any discontinuation pursuant to paragraph

(c)(2) or (j) of this section of the applicability of subpart CCCCC or DDDDD of part 97 of this chapter to the sources in a State and areas of Indian country within the borders of the State subject to the State's SIP authority with regard to emissions occurring in any control period, the following provisions shall continue to apply with regard to all CSAPR SO_2 Group 1 allowances and CSAPR SO_2 Group 2 allowances at any time allocated for any control period to any source or other entity in the State and areas of Indian country within the borders of the State subject to the State's SIP authority and shall apply to all entities, wherever located, that at any time held or hold such allowances:

(i) The provisions of §§ 97.626(c) and 97.726(c) of this chapter (concerning the transfer of CSAPR SO_2 Group 1 allowances and CSAPR SO_2 Group 2 allowances between certain Allowance Management System accounts under common control).

(ii) [Reserved]

* * * * *

■ 4. Add §§ 52.40 through 52.46 to subpart A to read as follows:

Sec.

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§ 52.40 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from sources not subject to the CSAPR ozone season trading program?

(a) *Purpose.* This section establishes Federal Implementation Plan requirements for new and existing units in the industries specified in paragraph (b) of this section to eliminate significant contribution to nonattainment, or interference with maintenance, of the 2015 8-hour ozone National Ambient Air Quality Standards in other states pursuant to 42 U.S.C. 7410(a)(2)(D)(i)(I).

(b) *Definitions.* The terms used in this section and §§ 52.41 through § 52.46 are defined as follows:

Calendar year means the period between January 1 and December 31, inclusive, for a given year.

Existing affected unit means any affected unit for which construction commenced before August 4, 2023.

New affected unit means any affected unit for which construction commenced on or after August 4, 2023.

Operator means any person who operates, controls, or supervises an affected unit and shall include, but not be limited to, any holding company, utility system, or plant manager of such affected unit.

Owner means any holder of any portion of the legal or equitable title in an affected unit.

Potential to emit means the maximum capacity of a unit to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the unit to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a unit.

Rolling average means the weighted average of all data, meeting quality assurance and quality control (QA/QC) requirements in this part or otherwise normalized, collected during the applicable averaging period. The period of a rolling average stipulates the frequency of data averaging and reporting. To demonstrate compliance with an operating parameter a 30-day rolling average period requires calculation of a new average value each operating day and shall include the average of all the hourly averages of the specific operating parameter. For demonstration of compliance with an emissions limit based on pollutant concentration, a 30-day rolling average is comprised of the average of all the hourly average concentrations over the previous 30 operating days. For demonstration of compliance with an emissions limit based on lbs-pollutant per production unit, the 30-day rolling average is calculated by summing the hourly mass emissions over the previous 30 operating days, then dividing that sum by the total production during the same period.

(c) *General requirements.* (1) The NO_X emissions limitations or emissions control requirements and associated compliance requirements for the following listed source categories not subject to the CSAPR ozone season trading program constitute the Federal Implementation Plan provisions that relate to emissions of NO_X during the ozone season (defined as May 1 through September 30 of a calendar year): §§ 52.41 for engines in the Pipeline Transportation of Natural Gas Industry, 52.42 for kilns in the Cement and Concrete Product Manufacturing Industry, 52.43 for reheat furnaces in the Iron and Steel Mills and Ferroalloy Manufacturing Industry, 52.44 for furnaces in the Glass and Glass Product Manufacturing Industry, 52.45 for boilers in the Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills industries, and 52.46 for Municipal Waste Combustors.

(2) The provisions of this section or § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 apply to affected units located in each of the following States, including Indian country located within the borders of such States, beginning in the 2026 ozone season and in each subsequent ozone season: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia.

(3) The testing, monitoring, recordkeeping, and reporting requirements of this section or § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 only apply during the ozone season, except as otherwise specified in these sections. Additionally, if an owner or operator of an affected unit chooses to conduct a performance or compliance test outside of the ozone season, all recordkeeping, reporting, and notification requirements associated

with that test shall apply, without regard to whether they occur during the ozone season.

(d) *Requests for extension of compliance.* (1) The owner or operator of an existing affected unit under § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 that cannot comply with the applicable requirements in those sections by May 1, 2026, due to circumstances entirely beyond the owner or operator's control, may request an initial compliance extension to a date certain no later than May 1, 2027. The extension request must contain a demonstration of necessity consistent with the requirements of paragraph (d)(3) of this section.

(2) If, after the EPA has granted a request for an initial compliance extension, the source remains unable to comply with the applicable requirements in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 by the extended compliance date due to circumstances entirely beyond the owner or operator's control, the owner or operator may apply for a second compliance extension to a date certain no later than May 1, 2029. The extension request must contain an updated demonstration of necessity consistent with the requirements of paragraph (d)(3) of this section.

(3) Each request for a compliance extension shall demonstrate that the owner or operator has taken all steps possible to install the controls necessary for compliance with the applicable requirements in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 by the applicable compliance date and shall:

(i) Identify each affected unit for which the owner or operator is seeking the compliance extension;

(ii) Identify and describe the controls to be installed at each affected unit to comply with the applicable requirements in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46;

(iii) Identify the circumstances entirely beyond the owner or operator's control that necessitate additional time to install the identified controls;

(iv) Identify the date(s) by which on-site construction, installation of control equipment, and/or process changes will be initiated;

(v) Identify the owner or operator's proposed compliance date. A request for an initial compliance extension under paragraph (d)(1) of this section must specify a proposed compliance date no later than May 1, 2027, and state whether the owner or operator anticipates a need to request a second compliance extension. A request for a second compliance extension under paragraph (d)(2) of this section must specify a proposed compliance date no later than May 1, 2029, and identify additional actions taken by the owner or operator to ensure that the affected unit(s) will be in compliance with the applicable requirements in this section by that proposed compliance date;

(vi) Include all information obtained from control technology vendors demonstrating that the identified controls cannot be installed by the applicable compliance date;

(vii) Include any and all contract(s) entered into for the installation of the identified controls or an explanation as to why no contract is necessary or obtainable; and

(viii) Include any permit(s) obtained for the installation of the identified controls or, where a required permit has not yet been issued, a copy of the permit application submitted to the permitting authority and a statement from the permitting authority identifying its anticipated timeframe for issuance of such permit(s).

(4) Each request for a compliance extension shall be submitted via the Compliance and Emissions Data Reporting Interface (CEDRI) or analogous electronic submission system provided by the EPA no later than 180 days prior to the applicable compliance date. Until an extension has been granted by the Administrator under this section, the owner or operator of an affected unit shall comply with all applicable requirements of this section and shall remain subject to the May 1, 2026 compliance date or the initial extended compliance date, as applicable. A denial will be effective as of the date of denial.

(5) The owner or operator of an affected unit who has requested a compliance extension under this paragraph (d)(5) and is required to have a title V permit shall apply to have the relevant title V permit revised to incorporate the conditions of the extension of compliance. The conditions of a compliance extension granted under this paragraph (d)(5) will be incorporated into the affected unit's title V permit according to the provisions of an EPA-approved state operating permit program or the Federal title V regulations in 40 CFR part 71, whichever apply.

(6) Based on the information provided in any request made under paragraph (d) of this section or other information, the Administrator may grant an extension of time to comply with applicable requirements in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 consistent with the provisions of paragraph (d)(1) or (2) of this section. The decision to grant an extension will be provided by notification via the CEDRI or analogous electronic submission system provided by the EPA and publicly available, and will identify each affected unit covered by the extension; specify the termination date of the extension; and specify any additional conditions that the Administrator deems necessary to ensure timely installation of the necessary controls (*e.g.,* the date(s) by which on-site construction, installation of control equipment, and/or process changes will be initiated).

(7) The Administrator will provide notification via the CEDRI or analogous electronic submission system provided by the EPA to the owner or operator of an affected unit who has requested a compliance extension under this paragraph (d)(7) whether the submitted request is complete, that is, whether the request contains sufficient information to make a determination, within 60 calendar days after receipt of the original request and within 60 calendar days after receipt of any supplementary information.

(8) The Administrator will provide notification via the CEDRI or analogous electronic submission system provided by the EPA, which shall be publicly available, to the owner or operator of a decision to grant or intention to deny a request for a compliance extension within 60 calendar days after providing written notification pursuant to paragraph (d)(7) of this section that the submitted request is complete.

(9) Before denying any request for an extension of compliance, the Administrator will provide notification via the CEDRI or analogous electronic submission system provided by the EPA to the owner or operator in writing of the Administrator's intention to issue the denial, together with:

(i) Notice of the information and findings on which the intended denial is based; and

(ii) Notice of opportunity for the owner or operator to present via the CEDRI or analogous electronic submission system provided by the EPA, within 15 calendar days after he/she is notified of the intended denial, additional information or arguments to the Administrator before further action on the request.

(10) The Administrator's final decision to deny any request for an extension will be provided via the CEDRI or analogous electronic submission system provided by the EPA and publicly available, and will set forth the specific grounds on which the denial is based. The final decision will be made within 60 calendar days after presentation of additional information

or argument (if the request is complete), or within 60 calendar days after the deadline for the submission of additional information or argument under paragraph (d)(9)(ii) of this section, if no such submission is made.

(11) The granting of an extension under this section shall not abrogate the Administrator's authority under section 114 of the Clean Air Act (CAA or the Act).

(e) *Requests for case-by-case emissions limits.* (1) The owner or operator of an existing affected unit under § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 that cannot comply with the applicable requirements in those sections due to technical impossibility or extreme economic hardship may submit to the Administrator, by August 5, 2024, a request for approval of a case-by-case emissions limit. The request shall contain information sufficient for the Administrator to confirm that the affected unit is unable to comply with the applicable emissions limit, due to technical impossibility or extreme economic hardship, and to establish an appropriate alternative case-by-case emissions limit for the affected unit. Until a case-by-case emissions limit has been approved by the Administrator under this section, the owner or operator shall remain subject to all applicable requirements in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46. A denial will be effective as of the date of denial.

(2) Each request for a case-by-case emissions limit shall include, but not be limited to, the following:

(i) A demonstration that the affected unit cannot achieve the applicable emissions limit with available control technology due to technical impossibility or extreme economic hardship.

(A) A demonstration of technical impossibility shall include:

(*1*) Uncontrolled NO_X emissions for the affected unit established with a CEMS, or stack tests obtained during steady state operation in accordance with the applicable reference test methods of 40 CFR part 60, appendix A–4, any alternative test method approved by the EPA as of June 5, 2023, under 40 CFR 59.104(f), 60.8(b)(3), 61.13(h)(1)(ii), 63.7(e)(2)(ii)(2), or 65.158(a)(2) and available at the EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by the EPA through notice-and-comment rulemaking; and

(*2*) A demonstration that the affected unit cannot meet the applicable emissions limit even with available control technology, including:

(*i*) Stack test data or other emissions data for the affected unit; or

(*ii*) A third-party engineering assessment demonstrating that the affected unit cannot meet the applicable emissions limit with available control technology.

(B) A demonstration of extreme economic hardship shall include at least three vendor estimates of the costs of installing control technology necessary to meet the applicable emissions limit and other information that demonstrates, to the satisfaction of the Administrator, that the cost of complying with the applicable emissions limit would present an extreme economic hardship relative to the costs borne by other comparable sources in the industry.

(ii) An analysis of available control technology options and a proposed case-by-case emissions limit that represents the lowest emissions limitation technically achievable by the affected unit without causing extreme economic hardship relative to the costs borne by other comparable sources in the industry. The owner or operator may propose additional measures to reduce NO_X emissions, such as operational standards or work practice standards.

(iii) Calculations of the NO_X emissions reduction to be achieved through implementation of the proposed case-by-case emissions limit and any additional proposed measures, the difference between this NO_X emissions reduction level and the NO_X emissions reductions that would have occurred if the affected unit complied with the applicable emissions limitations in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46, and a description of the methodology used for these calculations.

(3) The owner or operator of an affected unit who has requested a case-by-case emissions limit under this paragraph (e)(3) and is required to have a title V permit shall apply to have the relevant title V permit revised to incorporate the case-by-case emissions limit. Any case-by-case emissions limit approved under this paragraph (e)(3) will be incorporated into the affected unit's title V permit according to the provisions of an EPA-approved state operating permit program or the Federal title V regulations in 40 CFR part 71, whichever apply.

(4) Based on the information provided in any request made under this paragraph (e)(4) or other information, the Administrator may approve a case-by-case emissions limit that will apply to an affected unit in lieu of the applicable emissions limit in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46. The decision to approve a case-by-case emissions limit will be provided via the CEDRI or analogous electronic submission system provided by the EPA in paragraph (d) of this section and publicly available, and will identify each affected unit covered by the case-by-case emissions limit.

(5) The Administrator will provide notification via the CEDRI or analogous electronic submission system provided by the EPA in paragraph (d) of this section to the owner or operator of an affected unit who has requested a case-by-case emissions limit under this paragraph (e)(5) whether the submitted request is complete, that is, whether the request contains sufficient information to make a determination, within 60 calendar days after receipt of the original request and within 60 calendar days after receipt of any supplementary information.

(6) The Administrator will provide notification via the CEDRI or analogous electronic submission system described by the EPA in paragraph (d) of this section, which shall be publicly available, to the owner or operator of a decision to approve or intention to deny the request within 60 calendar days after providing notification pursuant to paragraph (e)(5) of this section that the submitted request is complete.

(7) Before denying any request for a case-by-case emissions limit, the Administrator will provide notification via the CEDRI or analogous electronic submission system provided by the EPA to the owner or operator in writing of the Administrator's intention to issue the denial, together with:

(i) Notice of the information and findings on which the intended denial is based; and

(ii) Notice of opportunity for the owner or operator to present via the CEDRI or analogous electronic submission system provided by the EPA, within 15 calendar days after he/she is notified of the intended denial, additional information or arguments to the Administrator before further action on the request.

(8) The Administrator's final decision to deny any request for a case-by-case emissions limit will be provided by notification via the CEDRI or analogous electronic submission system provided by the EPAand publicly available, and will set forth the specific grounds on which the denial is based. The final decision will be made within 60 calendar days after presentation of additional information or argument (if the request is complete), or within 60 calendar days after the deadline for the

submission of additional information or argument under paragraph (e)(7)(ii) of this section, if no such submission is made.

(9) The approval of a case-by-case emissions limit under this section shall not abrogate the Administrator's authority under section 114 of the Act.

(f) *Recordkeeping requirements.* (1) The owner or operator of an affected unit subject to the provisions of this section or § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 shall maintain files of all information (including all reports and notifications) required by these sections recorded in a form suitable and readily available for expeditious inspection and review. The files shall be retained for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. At minimum, the most recent 2 years of data shall be retained on site. The remaining 3 years of data may be retained off site. Such files may be maintained on microfilm, on a computer, on computer floppy disks, on magnetic tape disks, or on microfiche.

(2) Any records required to be maintained by § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 that are submitted electronically via the EPA's Compliance and Emissions Data Reporting Interface (CEDRI) may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to the EPA as part of an on-site compliance evaluation.

(g) *CEDRI reporting requirements.* (1) You shall submit the results of the performance test following the procedures specified in paragraphs (g)(1)(i) through (iii) of this section:

(i) Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test. Submit the results of the performance test to the EPA via the CEDRI or analogous electronic reporting approach provided by the EPA to report data required by § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website.

(ii) Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test. The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI.

(iii)(A) The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as confidential business information (CBI). Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information submitted under paragraph (g)(1) or (2) of this section, you should submit a complete file, including information claimed to be CBI, to the EPA.

(B) The file must be generated using the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website.

(C) Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

(D) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the Office of Air Quality Planning and Standards (OAQPS) CBI Office at the email address *oaqpscbi@epa.gov*, and as described in this paragraph (g), should include clear CBI markings and be flagged to the attention of Lead of 2015 Ozone Transport FIP. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(E) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Lead of 2015 Ozone Transport FIP. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(F) All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(G) You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described in paragraphs (g)(1) and (2) of this section.

(2) Annual reports must be submitted via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46.

(3) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (g)(3)(i) through (vii) of this section.

(i) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(ii) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(iii) The outage may be planned or unplanned.

(iv) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(v) You must provide to the Administrator a written description identifying:

(A) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(vi) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(vii) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(4) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (g)(4)(i) through (v) of this section.

(i) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected unit, its contractors, or any entity controlled by the affected unit that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected unit (*e.g.,* large scale power outage).

(ii) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(iii) You must provide to the Administrator:

(A) A written description of the force majeure event;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(iv) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(v) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

§ 52.41 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Pipeline Transportation of Natural Gas Industry?

(a) *Definitions.* All terms not defined in this paragraph (a) shall have the meaning given to them in the Act and in subpart A of 40 CFR part 60.

Affected unit means an engine meeting the applicability criteria of this section.

Cap means the total amount of NO_X emissions, in tons per day on a 30-day rolling average basis, that is collectively allowed from all of the affected units covered by a Facility-Wide Averaging Plan and is calculated as the sum each affected unit's NO_X emissions at the emissions limit applicable to such unit under paragraph (c) of this section, converted to tons per day in accordance with paragraph (d)(3) of this section.

Emergency engine means any stationary reciprocating internal combustion engine (RICE) that meets all of the criteria in paragraphs (i) and (ii) of this definition. All emergency stationary RICE must comply with the requirements specified in paragraph (b)(1) of this section in order to be considered emergency engines. If the engine does not comply with the requirements specified in paragraph (b)(1), it is not considered an emergency engine under this section.

(i) The stationary engine is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(ii) The stationary RICE is operated under limited circumstances for purposes other than those identified in paragraph (i) of this definition, as specified in paragraph (b)(1) of this section.

Facility means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same ''Major Group'' (*i.e.,* which have the same first two digit code as described in the Standard Industrial Classification Manual, 1987). For purposes of this section, a facility may not extend beyond the 20 states identified in § 52.40(b)(2).

Four stroke means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

ISO conditions means 288 Kelvin (15 °C), 60 percent relative humidity, and 101.3 kilopascals pressure.

Lean burn means any two-stroke or four-stroke spark ignited reciprocating internal combustion engine that does not meet the definition of a rich burn engine.

Local Distribution Companies (LDCs) are companies that own or operate distribution pipelines, but not interstate pipelines or intrastate pipelines, that physically deliver natural gas to end users and that are within a single state that are regulated as separate operating companies by State public utility commissions or that operate as independent municipally-owned distribution systems. LDCs do not include pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and farm taps upstream of the local distribution company inlet.

Local Distribution Company (LDC) custody transfer station means a metering station where the LDC receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

Nameplate rating means the manufacturer's maximum design capacity in horsepower (hp) at the installation site conditions. Starting from the completion of any physical change in the engine resulting in an increase in the maximum output (in hp) that the engine is capable of producing on a steady state basis and during continuous operation, such increased maximum output shall be as specified by the person conducting the physical change.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane) or non-hydrocarbons, composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Natural gas-fired means that greater than or equal to 90% of the engine's heat input, excluding recirculated or recuperated exhaust heat, is derived from the combustion of natural gas.

Natural gas processing plant means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas production facility means all equipment at a single stationary source directly associated with one or more natural gas wells upstream of the natural gas processing plant. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

Operating day means a 24-hour period beginning at 12:00 midnight during which any fuel is combusted at any time in the engine.

Pipeline transportation of natural gas means the movement of natural gas through an interconnected network of compressors and pipeline components, including the compressor and pipeline network used to transport the natural gas from processing plants over a distance (intrastate or interstate) to and from storage facilities, to large natural gas end-users, and prior to delivery to a ''local distribution company custody transfer station'' (as defined in this section) of an LDC that provides the natural gas to end-users. *Pipeline transportation of natural gas* does not include natural gas production facilities, natural gas processing plants, or the portion of a compressor and pipeline network that is upstream of a natural gas processing plant.

Reciprocating internal combustion engine (RICE) means a reciprocating engine in which power, produced by heat and/or pressure that is developed in the engine combustion chambers by the burning of a mixture of air and fuel, is subsequently converted to mechanical work.

Rich burn means any four-stroke spark ignited reciprocating internal combustion engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Internal combustion engines originally manufactured as rich burn engines but modified with passive emissions control technology for nitrogen oxides (NO_X) (such as pre-combustion chambers) will be considered lean burn engines. Existing affected unit where there are no manufacturer's recommendations regarding air/fuel ratio will be considered rich burn engines if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Spark ignition means a reciprocating internal combustion engine utilizing a spark plug (or other sparking device) to ignite the air/fuel mixture and with operating characteristics significantly similar to the theoretical Otto combustion cycle.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Two stroke means a type of reciprocating internal combustion engine which completes the power cycle in a single crankshaft revolution by combining the intake and compression operations into one stroke (one-half revolution) and the power and exhaust operations into a second stroke. This system requires auxiliary exhaust scavenging of the combustion products and inherently runs lean (excess of air) of stoichiometry.

(b) *Applicability.* You are subject to the requirements under this section if you own or operate a new or existing natural gas-fired spark ignition engine, other than an emergency engine, with a nameplate rating of 1,000 hp or greater that is used for pipeline transportation of natural gas and is located within any of the States listed in § 52.40(c)(2), including Indian country located within the borders of any such State(s).

(1) For purposes of this section, the owner or operator of an emergency stationary RICE must operate the RICE according to the requirements in paragraphs (b)(1)(i) through (iii) of this section to be treated as an emergency stationary RICE. In order for stationary RICE to be treated as an emergency RICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for up to 50 hours per year, as described in paragraphs (b)(1)(i) through (iii), is prohibited. If you do not operate the RICE according to the requirements in paragraphs (b)(1)(i) through (iii), the RICE will not be considered an emergency engine under this section and must meet all requirements for affected units in this section.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) The owner or operator may operate your emergency stationary RICE for maintenance checks and readiness testing for a maximum of 100 hours per calendar year, provided that the tests are recommended by a Federal, state, or local government agency, the manufacturer, the vendor, or the insurance company associated with the engine. Any operation for non-emergency situations as allowed by paragraph (b)(1)(iii) of this section counts as part of the 100 hours per calendar year allowed by paragraph (b)(1)(ii) of this section. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records confirming that Federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year. Any approval of a petition for additional hours granted by the Administrator under 40 CFR part 63, subpart ZZZZ, shall constitute approval by the Administrator of the same petition under this paragraph (b)(1)(ii).

(iii) Emergency stationary RICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (b)(1)(ii) of this section.

(2) If you own or operate a natural gas-fired two stroke lean burn spark ignition engine manufactured after July 1, 2007 that is meeting the applicable emissions limits in 40 CFR part 60, subpart JJJJ, table 1, the engine is not an affected unit under this section and you do not have to comply with the requirements of this section.

(3) If you own or operate a natural gas-fired four stroke lean or rich burn spark ignition engine manufactured after July 1, 2010, that is meeting the applicable emissions limits in 40 CFR part 60, subpart JJJJ, table 1, the engine is not an affected unit under this section and you do not have to comply with the requirements of this section.

(c) *Emissions limitations.* If you are the owner or operator of an affected unit, you must meet the following emissions limitations on a 30-day rolling average basis during the 2026 ozone season and in each ozone season thereafter:

(1) Natural gas-fired four stroke rich burn spark ignition engine: 1.0 grams per hp-hour (g/hp-hr);

(2) Natural gas-fired four stroke lean burn spark ignition engine: 1.5 g/hp-hr; and

(3) Natural gas-fired two stroke lean burn spark ignition engine: 3.0 g/hp-hr.

(d) *Facility-Wide Averaging Plan.* If you are the owner or operator of a facility containing more than one affected unit, you may submit a request via the CEDRI or analogous electronic submission system provided by the EPA to the Administrator for approval of a proposed Facility-Wide Averaging Plan as an alternative means of compliance with the applicable emissions limits in paragraph (c) of this section. Any such request shall be submitted to the Administrator on or before October 1st of the year prior to each emissions averaging year. The Administrator will approve a proposed Facility-Wide Averaging Plan submitted under this paragraph (d) if the Administrator determines that the proposed Facility-Wide Averaging Plan meets the requirements of this paragraph (d), will provide total emissions reductions equivalent to or greater than those achieved by the applicable emissions limits in paragraph (c), and identifies satisfactory means for determining initial and continuous compliance, including appropriate testing, monitoring, recordkeeping, and reporting requirements. You may only include affected units (*i.e.,* engines meeting the applicability criteria in paragraph (b) of this section) in a Facility-Wide Averaging Plan. Upon EPA approval of a proposed Facility-Wide Averaging Plan, you cannot withdraw any affected unit listed in such plan, and the terms of the plan may not be changed unless approved in writing by the Administrator.

(1) Each request for approval of a proposed Facility-Wide Averaging Plan shall include, but not be limited to:

(i) The address of the facility;

(ii) A list of all affected units at the facility that will be covered by the plan, identified by unit identification number, the engine manufacturer's name, and model;

(iii) For each affected unit, a description of any existing NO_X emissions control technology and the date of installation, and a description of any NO_X emissions control technology to be installed and the projected date of installation;

(iv) Identification of the emissions cap, calculated in accordance with paragraph (d)(3) of this section, that all affected units covered by the proposed Facility-Wide Averaging Plan will be subject to during the ozone season, together with all assumptions included in such calculation; and

(iv) Adequate provisions for testing, monitoring, recordkeeping, and reporting for each affected unit.

(2) Upon the Administrator's approval of a proposed Facility-Wide Averaging Plan, the owner or operator of the affected units covered by the Facility-Wide Averaging Plan shall comply with the cap identified in the plan in lieu of the emissions limits in paragraph (c) of this section. You will be in compliance with the cap if the sum of NO_X emissions from all units covered by the Facility-Wide Averaging Plan, in tons per day on a 30-day rolling average basis, is less than or equal to the cap.

(3) The owner or operator will calculate the cap according to equation 1 to this paragraph (d)(3). You will monitor and record daily hours of engine operation for use in calculating the cap on a 30-day rolling average basis. You will base the hours of operation on hour readings from a non-resettable hour meter or an equivalent monitoring device.

Equation 1 to Paragraph (d)(3)

$$Cap\ (tons\ per\ day) = 907{,}184.74\ x \sum_{i=1}^{N} (R_{li}\ x\ DC\ x\ H_i)$$

Where:

H_i = the average daily operating hours based on the highest consecutive 30-day period during the ozone season of the two most recent years preceding the emissions averaging year (hours).

i = each affected unit included in the Cap.

N = number of affected units.

DC = the engine manufacturer's design maximum capacity in horsepower (hp) at the installation site conditions.

R_{li} = the emissions limit for each affected unit from paragraph (c) of this section (grams/hp-hr).

(i) Any affected unit for which less than two years of operating data are available shall not be included in the Facility-Wide Averaging Plan unless the owner or operator extrapolates the available operating data for the affected unit to two years of operating data, for use in calculating the emissions cap in accordance with paragraph (d)(3) of this section.

(ii) [Reserved]

(4) The owner or operator of an affected units covered by an EPA-approved Facility-Wide Averaging Plan will be in violation of the cap if the sum of NO_X emissions from all such units, in tons per day on a 30-day rolling average basis, exceeds the cap. Each day of noncompliance by each affected unit covered by the Facility-Wide Averaging Plan shall be a violation of the cap until corrective action is taken to achieve compliance.

(e) *Testing and monitoring requirements.* (1) If you are the owner or operator of an affected unit subject to a NO_X emissions limit under paragraph (c) of this section, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions.

(2) If you are the owner or operator of an affected unit and are operating a NO_X continuous emissions monitoring system (CEMS) that monitors NO_X emissions from the affected unit, you may use the CEMS data in lieu of the annual performance tests and parametric monitoring required under this section. You must meet the following requirements for using CEMS to monitor NO_X emissions:

(i) You shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring NO_X emissions and either oxygen (O_2) or carbon dioxide (CO_2).

(ii) The CEMS shall be operated and data recorded during all periods of operation during the ozone season of the affected unit except for CEMS breakdowns and repairs. Data shall be recorded during calibration checks and zero and span adjustments.

(iii) The 1-hour average NO_X emissions rates measured by the CEMS shall be used to calculate the average emissions rates to demonstrate compliance with the applicable emissions limits in this section.

(iv) The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(v) When NO_X emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data will be obtained by using standby monitoring systems, Method 7 of 40 CFR part 60, appendix A–4, Method 7A of 40 CFR part 60, appendix A–4, or other approved reference methods to provide emissions data for a minimum of 75 percent of the operating hours in each affected unit operating day, in at least 22 out of 30 successive operating days.

(3)(i) If you are the owner or operator of a new affected unit, you must conduct an initial performance test within six months of engine startup and conduct subsequent performance tests every twelve months thereafter to demonstrate compliance. If pollution control equipment is installed to comply with a NO_X emissions limit in paragraph (c) of this section, however, the initial performance test shall be conducted within 90 days of such installation.

(ii) If you are the owner or operator of an existing affected unit, you must conduct an initial performance test within six months of becoming subject to an emissions limit under paragraph (c) of this section and conduct subsequent performance tests every twelve months thereafter to demonstrate compliance. If pollution control equipment is installed to comply with a NO_X emissions limit in paragraph (c) of this section, however, the initial performance test shall be conducted within 90 days of such installation.

(iii) If you are the owner or operator of a new or existing affected unit that is only operated during peak demand periods outside of the ozone season and the engine's hours of operation during the ozone season are 50 hours or less, the affected unit is not subject to the testing and monitoring requirements of this paragraph (e)(3)(iii) as long as you record and report your hours of operation during the ozone season in accordance with paragraphs (f) and (g) of this section.

(iv) If you are the owner or operator of an affected unit, you must conduct all performance tests consistent with the requirements of 40 CFR 60.4244 in accordance with the applicable reference test methods identified in table 2 to subpart JJJJ of 40 CFR part 60, any alternative test method approved by the EPA as of June 5, 2023, under 40 CFR 59.104(f), 60.8(b)(3), 61.13(h)(1)(ii), 63.7(e)(2)(ii), or 65.158(a)(2) and available at the EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by the EPA through notice-and-comment rulemaking. To determine compliance with the NO_X emissions limit in paragraph (c) of this section, the emissions rate shall be calculated in accordance with the requirements of 40 CFR 60.4244(d).

(4) If you are the owner or operator of an affected unit that has a non-selective catalytic reduction (NSCR) control device to reduce emissions, you must:

(i) Monitor the inlet temperature to the catalyst daily and conduct maintenance if the temperature is not within the observed inlet temperature range from the most recent performance test or the temperatures specified by the manufacturer if no performance test was required by this section; and

(ii) Measure the pressure drop across the catalyst monthly and conduct maintenance if the pressure drop across the catalyst changes by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the most recent performance test.

(5) If you are the owner of operator of an affected unit not using an NSCR control device to reduce emissions, you are required to conduct continuous parametric monitoring to assure compliance with the applicable emissions limits according to the requirements in paragraphs (e)(5)(i) through (vi) of this section.

(i) You must prepare a site-specific monitoring plan that includes all of the following monitoring system design, data collection, and quality assurance and quality control elements:

(A) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(B) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements.

(C) Equipment performance evaluations, system accuracy audits, or other audit procedures.

(D) Ongoing operation and maintenance procedures in accordance with the requirements of paragraph (e)(1) of this section.

(E) Ongoing recordkeeping and reporting procedures in accordance with the requirements of paragraphs (f) and (g) of this section.

(ii) You must continuously monitor the selected operating parameters according to the procedures in your site-specific monitoring plan.

(iii) You must collect parametric monitoring data at least once every 15 minutes.

(iv) When measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(v) You must conduct performance evaluations, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(vi) You must conduct a performance evaluation of each parametric monitoring device in accordance with your site-specific monitoring plan.

(6) If you are the owner or operator of an affected unit that is only operated during peak periods outside of the ozone season and your hours of operation during the ozone season are 0, you are not subject to the testing and monitoring requirements of this paragraph (e)(6) so long as you record and report your hours of operation during the ozone season in accordance with paragraphs (f) and (g) of this section.

(f) *Recordkeeping requirements.* If you are the owner or operator of an affected unit, you must keep records of:

(1) Performance tests conducted pursuant to paragraph (e)(2) of this section, including the date, engine settings on the date of the test, and documentation of the methods and results of the testing.

(2) Catalyst monitoring required by paragraph (e)(3) of this section, if applicable, and any actions taken to address monitored values outside the temperature or pressure drop parameters, including the date and a description of actions taken.

(3) Parameters monitored pursuant to the facility's site-specific parametric monitoring plan.

(4) Hours of operation on a daily basis.

(5) Tuning, adjustments, or other combustion process adjustments and the date of the adjustment(s).

(6) For any Facility-Wide Averaging Plan approved by the Administrator under paragraph (d) of this section, daily calculations of total NO_X emissions to demonstrate compliance with the cap during the ozone season. You must use the equation in this paragraph (f)(6) to calculate total NO_X emissions from all affected units covered by the Facility-Wide Averaging Plan, in tons per day on a 30-day rolling average basis, for purposes of determining compliance with the cap during the ozone season. A new 30-day rolling average emissions rate in tpd is calculated for each operating day during the ozone season, using the 30-day rolling average daily operating hours for the preceding 30 operating days.

Equation 2 to Paragraph (f)(6)

$$\sum_{i=1}^{N} (R_{ai}\ x\ DC\ x\ H_{ai}) \leq Cap\ (tons\ per\ day)$$

Where:

H_{ai} = the consecutive 30-day rolling average daily operating hours for the preceding 30 operating days during ozone season (hours).
i = each affected unit.
N = number of affected units.
DC = the engine manufacturer's maximum design capacity in horsepower (hp) at the installation site conditions.
R_{ai} = the actual emissions rate for each affected unit based on the most recent performance test results, (grams/hp-hr).

(g) *Reporting requirements.* (1) If you are the owner or operator of an affected unit, you must submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in § 52.40(g) within 60 days after completing each performance test required by this section.

(2) If you are the owner or operator of an affected unit, you are required to submit excess emissions reports for any excess emissions that occurred during the reporting period. Excess emissions are defined as any calculated 30-day rolling average NO_X emissions rate that exceeds the applicable emissions limit in paragraph (c) of this section. Excess emissions reports must be submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section following the procedures specified in § 52.40(g).

(3) If you are the owner or operator of an affected unit, you must submit an annual report in PDF format to the EPA by January 30th of each year via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section. Annual reports shall be submitted following the procedures in paragraph (g) of this section. The report shall contain the following information:

(i) The name and address of the owner and operator;

(ii) The address of the subject engine;

(iii) Longitude and latitude coordinates of the subject engine;

(iv) Identification of the subject engine;

(v) Statement of compliance with the applicable emissions limit under paragraph (c) of this section or a Facility-Wide Averaging Plan under paragraph (d) of this section;

(vi) Statement of compliance regarding the conduct of maintenance and operations in a manner consistent with good air pollution control practices for minimizing emissions;

(vii) The date and results of the performance test conducted pursuant to paragraph (e) of this section;

(viii) Any records required by paragraph (f) of this section, including records of parametric monitoring data, to demonstrate compliance with the applicable emissions limit under paragraph (c) of this section or a Facility-Wide Averaging Plan under paragraph (d) of this section, if applicable;

(ix) If applicable, a statement documenting any change in the operating characteristics of the subject engine; and

(x) A statement certifying that the information included in the annual report is complete and accurate.

§ 52.42 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Cement and Concrete Product Manufacturing Industry?

(a) *Definitions.* All terms not defined in this paragraph (a) shall have the meaning given to them in the Act and in subpart A of 40 CFR part 60.

Affected unit means a cement kiln meeting the applicability criteria of this section.

Cement kiln means an installation, including any associated pre-heater or pre-calciner devices, that produces clinker by heating limestone and other materials to produce Portland cement.

Cement plant means any facility manufacturing cement by either the wet or dry process.

Clinker means the product of a cement kiln from which finished cement is manufactured by milling and grinding.

Operating day means a 24-hour period beginning at 12:00 midnight during which the kiln produces clinker at any time.

(b) *Applicability.* You are subject to the requirements of this section if you own or operate a new or existing cement kiln that emits or has the potential to emit 100 tons per year or more of NO_X on or after August 4, 2023, and is located within any of the States listed in § 52.40(c)(2), including Indian country located within the borders of any such State(s). Any existing cement kiln with a potential to emit of 100 tons per year or more of NO_X on August 4, 2023, will continue to be subject to the requirements of this section even if that unit later becomes subject to a physical or operational limitation that lowers its potential to emit below 100 tons per year of NO_X.

(c) *Emissions limitations.* If you are the owner or operator of an affected unit, you must meet the following emissions limitations on a 30-day rolling average basis during the 2026 ozone season and in each ozone season thereafter:

(1) Long wet kilns: 4.0 lb/ton of clinker;

(2) Long dry kilns: 3.0 lb/ton of clinker;

(3) Preheater kilns: 3.8 lb/ton of clinker;

(4) Precalciner kilns: 2.3 lb/ton of clinker; and

(5) Preheater/Precalciner kilns: 2.8 lb/ton of clinker.

(d) *Testing and monitoring requirements.* (1) If you are the owner or operator of an affected unit you must conduct performance tests, on an annual basis, in accordance with the applicable reference test methods of 40 CFR part 60, appendix A–4, any alternative test method approved by the EPA as of June 5, 2023, under 40 CFR 59.104(f), 60.8(b)(3), 61.13(h)(1)(ii), 63.7(e)(2)(ii), or 65.158(a)(2) and available at the EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by the EPA through notice-and-comment rulemaking. The annual performance test does not have to be performed during the ozone season. You must calculate and record the 30-operating day rolling average emissions rate of NO_X as the total of all hourly emissions data for a cement kiln in the preceding 30 days, divided by the total tons of clinker produced in that kiln during the same 30-operating day period, using equation 1 to this paragraph (d)(1):

Equation 1 to Paragraph (d)(1)

$$E_{30D} = k\left(\frac{\sum_{i=1}^{N} Ci\ Qi}{P}\right)$$

Where:

E_{30D} = 30 kiln operating day average emissions rate of NO_X, in lbs/ton of clinker.
Ci = Concentration of NO_X for hour i, in ppm.
Qi = Volumetric flow rate of effluent gas for hour i, where Ci and Qi are on the same basis (either wet or dry), in scf/hr.

P = 30 days of clinker production during the same Time period as the NO_X emissions measured, in tons.
k = Conversion factor, 1.194×10^{-7} for NO_X, in lb/scf/ppm.
n = Number of kiln operating hours over 30 kiln operating days.

(2) If you are the owner or operator of an affected unit and are operating a NO_X continuous emissions monitoring system (CEMS) that monitors NO_X emissions from the affected unit, you may use the CEMS data in lieu of the annual performance tests and parametric monitoring required under this section. You must meet the following requirements for using CEMS to monitor NO_X emissions:

(i) You shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring NO_X emissions and either oxygen (O_2) or carbon dioxide (CO_2).

(ii) The CEMS shall be operated and data recorded during all periods of operation during the ozone season of the affected unit except for CEMS breakdowns and repairs. Data shall be recorded during calibration checks and zero and span adjustments.

(iii) The 1-hour average NO_X emissions rates measured by the CEMS shall be expressed in terms of lbs/ton of clinker and shall be used to calculate the average emissions rates to demonstrate compliance with the applicable emissions limits in this section.

(iv) The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(v) When NO_X emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emissions data will be obtained by using standby monitoring systems, Method 7 of 40 CFR part 60, appendix A–4, Method 7A of 40 CFR part 60, appendix A–4, or other approved reference methods to provide emissions data for a minimum of 75 percent of the operating hours in each affected unit operating day, in at least 22 out of 30 successive operating days.

(3) If you are the owner or operator of an affected unit not operating NO_X CEMS, you must conduct an initial performance test before the 2026 ozone season to establish appropriate indicator ranges for operating parameters and continuously monitor those operator parameters consistent with the requirements of paragraphs (d)(3)(i) through (v) of this section.

(i) You must monitor and record kiln stack exhaust gas flow rate, hourly clinker production rate or kiln feed rate, and kiln stack exhaust temperature during the initial performance test and subsequent annual performance tests to demonstrate continuous compliance with your NO_X emissions limits.

(ii) You must determine hourly clinker production by one of two methods:

(A) Install, calibrate, maintain, and operate a permanent weigh scale system to record weight rates of the amount of clinker produced in tons of mass per hour. The system of measuring hourly clinker production must be maintained within ±5 percent accuracy; or

(B) Install, calibrate, maintain, and operate a permanent weigh scale system to measure and record weight rates of the amount of feed to the kiln in tons of mass per hour. The system of measuring feed must be maintained within ±5 percent accuracy. Calculate your hourly clinker production rate using a kiln specific feed-to-clinker ratio based on reconciled clinker production rates determined for accounting purposes and recorded feed rates. This ratio should be updated monthly. Note that if this ratio changes at clinker reconciliation, you must use the new ratio going forward, but you do not have to retroactively change clinker production rates previously estimated.

(C) For each kiln operating hour for which you do not have data on clinker production or the amount of feed to the kiln, use the value from the most recent previous hour for which valid data are available.

(D) If you measure clinker production directly, record the daily clinker production rates; if you measure the kiln feed rates and calculate clinker production, record the daily kiln feed and clinker production rates.

(iii) You must use the kiln stack exhaust gas flow rate, hourly kiln production rate or kiln feed rate, and kiln stack exhaust temperature during the initial performance test and subsequent annual performance tests as indicators of NO_X operating parameters to demonstrate continuous compliance and establish site-specific indicator ranges for these operating parameters.

(iv) You must repeat the performance test annually to reassess and adjust the site-specific operating parameter indicator ranges in accordance with the results of the performance test.

(v) You must report and include your ongoing site-specific operating parameter data in the annual reports required under paragraph (e) of this section and semi-annual title V monitoring reports to the relevant permitting authority.

(e) *Recordkeeping requirements.* If you are the owner or operator of an affected unit, you shall maintain records of the following information for each day the affected unit operates:

(1) Calendar date;

(2) The average hourly NO_X emissions rates measured or predicted;

(3) The 30-day average NO_X emissions rates calculated at the end of each affected unit operating day from the measured or predicted hourly NO_X emissions rates for the preceding 30 operating days;

(4) Identification of the affected unit operating days when the calculated 30-day average NO_X emissions rates are in excess of the applicable site-specific NO_X emissions limit with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the affected unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emissions data have been excluded from the calculation of average emissions rates and the reasons for excluding data;

(7) If a CEMS is used to verify compliance:

(i) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(ii) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3 in appendix B to 40 CFR part 60; and

(iii) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of 40 CFR part 60, appendix F;

(8) Operating parameters required under paragraph (d) of this section to demonstrate compliance during the ozone season;

(9) Each fuel type, usage, and heat content; and

(10) Clinker production rates.

(f) *Reporting requirements.* (1) If you are the owner or operator of an affected unit, you shall submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in § 52.40(g) within 60 days after the date of completing each performance test required by this section.

(2) If you are the owner or operator of an affected unit, you are required to submit excess emissions reports for any excess emissions that occurred during the reporting period. Excess emissions are defined as any calculated 30-day rolling average NO_X emissions rate that exceeds the applicable emissions limit established under paragraph (c) of this section. Excess emissions reports must

be submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section following the procedures specified in § 52.40(g).

(3) If you are the owner or operator of an affected unit, you shall submit an annual report in PDF format to the EPA by January 30th of each year via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section. Annual reports shall be submitted following the procedures in § 52.40(g). The report shall include records all records required by paragraph (d) of this section, including record of CEMS data or operating parameters required by paragraph (d) to demonstrate continuous compliance the applicable emissions limits under paragraph (c) of this section.

(g) *Initial notification requirements for existing affected units.* (1) The requirements of this paragraph (g) apply to the owner or operator of an existing affected unit.

(2) The owner or operator of an existing affected unit that emits or has a potential to emit 100 tons per year or greater as of August 4, 2023, shall notify the Administrator via the CEDRI or analogous electronic submission system provided by the EPA that the unit is subject to this section. The notification, which shall be submitted not later than December 4, 2023, shall be submitted in PDF format to the EPA via CEDRI, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The notification shall provide the following information:

(i) The name and address of the owner or operator;

(ii) The address (*i.e.,* physical location) of the affected unit;

(iii) An identification of the relevant standard, or other requirement, that is the basis for the notification and the unit's compliance date; and

(iv) A brief description of the nature, size, design, and method of operation of the facility and an identification of the types of emissions points (units) within the facility subject to the relevant standard.

§ 52.43 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Iron and Steel Mills and Ferroalloy Manufacturing Industry?

(a) *Definitions.* All terms not defined in this paragraph (a) shall have the meaning given to them in the Act and in subpart A of 40 CFR part 60.

Affected unit means any reheat furnace meeting the applicability criteria of this section.

Day means a calendar day unless expressly stated to be a business day. In computing any period of time for recordkeeping and reporting purposes where the last day would fall on a Saturday, Sunday, or Federal holiday, the period shall run until the close of business of the next business day.

Low NO_X burner means a burner designed to reduce flame turbulence by the mixing of fuel and air and by establishing fuel-rich zones for initial combustion, thereby reducing the formation of NO_X.

Low-NO_X technology means any post-combustion NO_X control technology capable of reducing NO_X emissions by 40% from baseline emission levels as measured during pre-installation testing.

Operating day means a 24-hour period beginning at 12:00 midnight during which any fuel is combusted at any time in the reheat furnace.

Reheat furnace means a furnace used to heat steel product—including metal ingots, billets, slabs, beams, blooms and other similar products—for the purpose of deformation and rolling.

(b) *Applicability.* The requirements of this section apply to each new or existing reheat furnace at an iron and steel mill or ferroalloy manufacturing facility that directly emits or has the potential to emit 100 tons per year or more of NO_X on or after August 4, 2023, does not have low-NO_X burners installed, and is located within any of the States listed in § 52.40(c)(2), including Indian country located within the borders of any such State(s). Any existing reheat furnace with a potential to emit of 100 tons per year or more of NO_X on August 4, 2023, will continue to be subject to the requirements of this section even if that unit later becomes subject to a physical or operational limitation that lowers its potential to emit below 100 tons per year of NO_X.

(c) *Emissions control requirements.* If you are the owner or operator of an affected unit without low-NO_X burners already installed, you must install and operate low-NO_X burners or equivalent alternative low-NO_X technology designed to achieve at least a 40% reduction from baseline NO_X emissions in accordance with the work plan established pursuant to paragraph (d) of this section. You must meet the emissions limit established under paragraph (d) on a 30-day rolling average basis.

(d) *Work plan requirements.* (1) The owner or operator of each affected unit must submit a work plan for each affected unit by August 5, 2024. The work plan must be submitted via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section following the procedures specified in § 52.40(g). Each work plan must include a description of the affected unit and rated production and energy capacities, identification of the low-NO_X burner or alternative low NO_X technology selected, and the phased construction timeframe by which you will design, install, and consistently operate the device. Each work plan shall also include, where applicable, performance test results obtained no more than five years before August 4, 2023, to be used as baseline emissions testing data providing the basis for required emissions reductions. If no such data exist, then the owner or operator must perform pre-installation testing as described in paragraph (e)(3) of this section.

(2) The owner or operator of an affected unit shall design each low-NO_X burner or alternative low-NO_X technology identified in the work plan to achieve NO_X emission reductions by a minimum of 40% from baseline emission levels measured during performance testing that meets the criteria set forth in paragraph (e)(1) of this section, or during pre-installation testing as described in paragraph (e)(3) of this section. Each low-NO_X burner or alternative low-NO_X technology shall be continuously operated during all production periods according to paragraph (c) of this section.

(3) The owner or operator of an affected unit shall establish an emissions limit in the work plan that the affected unit must comply with in accordance with paragraph (c) of this section.

(4) The EPA's action on work plans:

(i) The Administrator will provide via the CEDRI or analogous electronic submission system provided by the EPA notification to the owner or operator of an affected unit if the submitted work plan is complete, that is, whether the request contains sufficient information to make a determination, within 60 calendar days after receipt of the original work plan and within 60 calendar days after receipt of any supplementary information.

(ii) The Administrator will provide notification via the CEDRI or analogous electronic submission system provided by the EPA, which shall be publicly available, to the owner or operator of a decision to approve or intention to disapprove the work plan within 60 calendar days after providing written notification pursuant to paragraph (d)(4)(i) of this section that the submitted work plan is complete.

(iii) Before disapproving a work plan, the Administrator will notify the owner or operator via the CEDRI or analogous electronic submission system provided by the EPA of the Administrator's intention to issue the disapproval, together with:

(A) Notice of the information and findings on which the intended disapproval is based; and

(B) Notice of opportunity for the owner or operator to present in writing, within 15 calendar days after he/she is notified of the intended disapproval, additional information or arguments to the Administrator before further action on the work plan.

(iv) The Administrator's final decision to disapprove a work plan will be via the CEDRI or analogous electronic submission system provided by the EPA and publicly available, and will set forth the specific grounds on which the disapproval is based. The final decision will be made within 60 calendar days after presentation of additional information or argument (if the submitted work plan is complete), or within 60 calendar days after the deadline for the submission of additional information or argument under paragraph (d)(5)(iii)(B) of this section, if no such submission is made.

(v) If the Administrator disapproves the submitted work plan for failure to satisfy the requirements of paragraphs (c) and (d)(1) through (3) of this section, or if the owner or operator of an affected unit fails to submit a work plan by August 5, 2024, the owner or operator will be in violation of this section. Each day that the affected unit operates following such disapproval or failure to submit shall constitute a violation.

(e) *Testing and monitoring requirements.* (1) If you are the owner or operator of an affected unit you must conduct performance tests, on an annual basis, in accordance with the applicable reference test methods of 40 CFR part 60, appendix A–4, any alternative test method approved by the EPA as of June 5, 2023, under 40 CFR 59.104(f), 60.8(b)(3), 61.13(h)(1)(ii), 63.7(e)(2)(ii), or 65.158(a)(2) and available at the EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by the EPA through notice-and-comment rulemaking. The annual performance test does not have to be performed during the ozone season.

(2) If you are the owner or operator of an affected unit and are operating a NO_X continuous emissions monitoring system (CEMS) that monitors NO_X emissions from the affected unit, you may use the CEMS data in lieu of the annual performance tests and parametric monitoring required under this section. You must meet the following requirements for using CEMS to monitor NO_X emissions:

(i) You shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring NO_X emissions and either oxygen (O_2) or carbon dioxide (CO_2).

(ii) The CEMS shall be operated and data recorded during all periods of operation during the ozone season of the affected unit except for CEMS breakdowns and repairs. Data shall be recorded during calibration checks and zero and span adjustments.

(iii) The 1-hour average NO_X emissions rates measured by the CEMS shall be expressed in form of the emissions limit established in the work plan and shall be used to calculate the average emissions rates to demonstrate compliance with the applicable emissions limits established in the work plan.

(iv) The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(v) When NO_X emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emissions data will be obtained by using standby monitoring systems, Method 7 of 40 CFR part 60, appendix A–4, Method 7A of 40 CFR part 60, appendix A–4, or other approved reference methods to provide emissions data for a minimum of 75 percent of the operating hours in each affected unit operating day, in at least 22 out of 30 successive operating days.

(3) If you are the owner or operator of an affected unit not operating NO_X CEMS, you must conduct an initial performance test before the 2026 ozone season to establish appropriate indicator ranges for operating parameters and continuously monitor those operator parameters consistent with the requirements of paragraphs (e)(3)(i) through (iv) of this section.

(i) You must monitor and record stack exhaust gas flow rate and temperature during the initial performance test and subsequent annual performance tests to demonstrate continuous compliance with your NO_X emissions limits.

(ii) You must use the stack exhaust gas flow rate and temperature during the initial performance test and subsequent annual performance tests to establish a site-specific indicator for these operating parameters.

(iii) You must repeat the performance test annually to reassess and adjust the site-specific operating parameter indicator ranges in accordance with the results of the performance test.

(iv) You must report and include your ongoing site-specific operating parameter data in the annual reports required under paragraph (f) of this section and semi-annual title V monitoring reports to the relevant permitting authority.

(f) *Recordkeeping requirements.* If you are the owner or operator of an affected unit, you shall maintain records of the following information for each day the affected unit operates:

(1) Calendar date;

(2) The average hourly NO_X emissions rates measured or predicted;

(3) The 30-day average NO_X emissions rates calculated at the end of each affected unit operating day from the measured or predicted hourly NO_X emissions rates for the preceding 30 operating days;

(4) Identification of the affected unit operating days when the calculated 30-day average NO_X emissions rates are in excess of the applicable site-specific NO_X emissions limit with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the affected unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emissions data have been excluded from the calculation of average emissions rates and the reasons for excluding data;

(7) If a CEMS is used to verify compliance:

(i) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(ii) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3 in appendix B to 40 CFR part 60; and

(iii) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of 40 CFR part 60, appendix F;

(8) Operating parameters required under paragraph (d) of this section to demonstrate compliance during the ozone season; and

(9) Each fuel type, usage, and heat content.

(g) *Reporting requirements.* (1) If you are the owner or operator of an affected unit, you shall submit a final report via the CEDRI or analogous electronic submission system provided by the EPA, by no later than March 30, 2026, certifying that installation of each selected control device has been completed. You shall include in the report the dates of final construction and relevant performance testing, where applicable, demonstrating compliance with the selected emission limits pursuant to paragraphs (c) and (d) of this section.

(2) If you are the owner or operator of an affected unit, you must submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in § 52.40(g) within 60 days after the date of completing each performance test required by this section.

(3) If you are the owner or operator of an affected unit, you are required to submit excess emissions reports for any excess emissions that occurred during the reporting period. Excess emissions are defined as any calculated 30-day rolling average NO_X emissions rate that exceeds the applicable emissions limit established under paragraphs (c) and (d) of this section. Excess emissions reports must be submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section following the procedures specified in § 52.40(g).

(4) If you are the owner or operator of an affected unit, you shall submit an annual report in PDF format to the EPA by January 30th of each year via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section. Annual reports shall be submitted following the procedures in § 52.40(g). The report shall include records all records required by paragraphs (e) and (f) of this section, including record of CEMS data or operating parameters required by paragraph (e) to demonstrate compliance the applicable emissions limits established under paragraphs (c) and (d) of this section.

(h) *Initial notification requirements for existing affected units.* (1) The requirements of this paragraph (h) apply to the owner or operator of an existing affected unit.

(2) The owner or operator of an existing affected unit that emits or has a potential to emit 100 tons per year or more of NO_X as of August 4, 2023, shall notify the Administrator via the CEDRI or analogous electronic submission system provided by the EPA that the unit is subject to this section. The notification, which shall be submitted not later than December 4, 2023, shall be submitted in PDF format to the EPA via CEDRI, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The notification shall provide the following information:

(i) The name and address of the owner or operator;

(ii) The address (*i.e.,* physical location) of the affected unit;

(iii) An identification of the relevant standard, or other requirement, that is the basis for the notification and the unit's compliance date; and

(iv) A brief description of the nature, size, design, and method of operation of the facility and an identification of the types of emissions points (units) within the facility subject to the relevant standard.

§ 52.44 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Glass and Glass Product Manufacturing Industry?

(a) *Definitions.* All terms not defined in this paragraph (a) shall have the meaning given to them in the Act and in subpart A of 40 CFR part 60.

Affected units means a glass manufacturing furnace meeting the applicability criteria of this section.

Borosilicate recipe means glass product composition of the following approximate ranges of weight proportions: 60 to 80 percent silicon dioxide, 4 to 10 percent total R_2O (*e.g.,* Na_2O and K_2O), 5 to 35 percent boric oxides, and 0 to 13 percent other oxides.

Container glass means glass made of soda-lime recipe, clear or colored, which is pressed and/or blown into bottles, jars, ampoules, and other products listed in Standard Industrial Classification (SIC) 3221 (SIC 3221).

Flat glass means glass made of soda-lime recipe and produced into continuous flat sheets and other products listed in SIC 3211.

Glass melting furnace means a unit comprising a refractory vessel in which raw materials are charged, melted at high temperature, refined, and conditioned to produce molten glass. The unit includes foundations, superstructure and retaining walls, raw material charger systems, heat exchangers, melter cooling system, exhaust system, refractory brick work, fuel supply and electrical boosting equipment, integral control systems and instrumentation, and appendages for conditioning and distributing molten glass to forming apparatuses. The forming apparatuses, including the float bath used in flat glass manufacturing and flow channels in wool fiberglass and textile fiberglass manufacturing, are not considered part of the glass melting furnace.

Glass produced means the weight of the glass pulled from the glass melting furnace.

Idling means the operation of a glass melting furnace at less than 25% of the permitted production capacity or fuel use capacity as stated in the operating permit.

Lead recipe means glass product composition of the following ranges of weight proportions: 50 to 60 percent silicon dioxide, 18 to 35 percent lead oxides, 5 to 20 percent total R_2O (*e.g.,* Na_2O and K_2O), 0 to 8 percent total R_2O_3 (*e.g.,* Al_2O_3), 0 to 15 percent total RO (*e.g.,* CaO, MgO), other than lead oxide, and 5 to 10 percent other oxides.

Operating day means a 24-hr period beginning at 12:00 midnight during which the furnace combusts fuel at any time but excludes any period of startup, shutdown, or idling during which the affected unit complies with the requirements in paragraphs (d) through (f) of this section, as applicable.

Pressed and blown glass means glass which is pressed, blown, or both, including textile fiberglass, noncontinuous flat glass, noncontainer glass, and other products listed in SIC 3229. It is separated into: Glass of borosilicate recipe, Glass of soda-lime and lead recipes, and Glass of opal, fluoride, and other recipes.

Raw material means minerals, such as silica sand, limestone, and dolomite; inorganic chemical compounds, such as soda ash (sodium carbonate), salt cake (sodium sulfate), and potash (potassium carbonate); metal oxides and other metal-based compounds, such as lead oxide, chromium oxide, and sodium antimonate; metal ores, such as chromite and pyrolusite; and other substances that are intentionally added to a glass manufacturing batch and melted in a glass melting furnace to produce glass. Metals that are naturally-occurring trace constituents or contaminants of other substances are not considered to be raw materials.

Shutdown means the period of time during which a glass melting furnace is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to a cold or ambient temperature as the fuel supply is turned off.

Soda-lime recipe means glass product composition of the following ranges of weight proportions: 60 to 75 percent silicon dioxide, 10 to 17 percent total R_2O (*e.g.,* Na_2O and K_2O), 8 to 20 percent total RO but not to include any PbO (*e.g.,* CaO, and MgO), 0 to 8 percent total R_2O_3 (*e.g.,* Al_2O_3), and 1 to 5 percent other oxides.

Startup means the period of time, after initial construction or a furnace rebuild, during which a glass melting furnace is heated to operating temperatures by the primary furnace combustion system, and systems and instrumentation are brought to stabilization.

Textile fiberglass means fibrous glass in the form of continuous strands having uniform thickness.

Wool fiberglass means fibrous glass of random texture, including accoustical board and tile (mineral wool), fiberglass insulation, glass wool, insulation (rock wool, fiberglass, slag, and silicia minerals), and mineral wool roofing mats.

(b) *Applicability.* You are subject to the requirements under this section if you own or operate a new or existing glass manufacturing furnace that directly emits or has the potential to emit 100 tons per year or more of NO_X on or after August 4, 2023, and is located within any of the States listed in § 52.40(c)(2), including Indian country located within the borders of any such State(s). Any existing glass manufacturing furnace with a potential to emit of 100 tons per year or more of NO_X on August 4, 2023, will continue to be subject to the requirements of this section even if that unit later becomes subject to a physical or operational limitation that lowers its potential to emit below 100 tons per year of NO_X.

(c) *Emissions limitations.* If you are the owner or operator of an affected unit, you must meet the emissions limitations in paragraphs (c)(1) and (2) of this section on a 30-day rolling average basis during the 2026 ozone season and in each ozone season thereafter. For the 2026 ozone season, the emissions limitations in paragraphs (c)(1) and (2) do not apply during shutdown and idling if the affected unit complies with the requirements in paragraphs (e) and (f) of this section, as applicable. For the 2027 and subsequent ozone seasons, the emissions limitations in paragraphs (c)(1) and (2) do not apply during startup, shutdown, and idling, if the affected unit complies with the requirements in paragraphs (d) through (f) of this section, as applicable.

(1) Container glass, pressed/blown glass, or fiberglass manufacturing furnace: 4.0 lb/ton of glass; and

(2) Flat glass manufacturing furnace: 7.0 lb/ton of glass.

(d) *Startup requirements.* (1) If you are the owner or operator of an affected unit, you shall submit via the CEDRI or analogous electronic submission system provided by the EPA, no later than 30 days prior to the anticipated date of startup, the following information to assure proper operation of the furnace:

(i) A detailed list of activities to be performed during startup and explanations to support the length of time needed to complete each activity.

(ii) A description of the material process flow rates, system operating parameters, and other information that the owner or operator shall monitor and record during the startup period.

(iii) Identification of the control technologies or strategies to be utilized.

(iv) A description of the physical conditions present during startup periods that prevent the controls from being effective.

(v) A reasonably precise estimate as to when physical conditions will have reached a state that allows for the effective control of emissions.

(2) The length of startup following activation of the primary furnace combustion system may not exceed:

(i) Seventy days for a container, pressed or blown glass furnace;

(ii) Forty days for a fiberglass furnace; and

(iii) One hundred and four days for a flat glass furnace and for all other glass melting furnaces not covered under paragraphs (d)(2)(i) and (ii) of this section.

(3) During the startup period, the owner or operator of an affected unit shall maintain the stoichiometric ratio of the primary furnace combustion system so as not to exceed 5 percent excess oxygen, as calculated from the actual fuel and oxidant flow measurements for combustion in the affected unit.

(4) The owner or operator of an affected unit shall place the emissions control system in operation as soon as technologically feasible during startup to minimize emissions.

(e) *Shutdown requirements.* (1) If you are the owner or operator of an affected unit, you shall submit via the CEDRI or analogous electronic submission system provided by the EPA to the Administrator, no later than 30 days prior to the anticipated date of shutdown, the following information to assure proper operation of the furnace:

(i) A detailed list of activities to be performed during shutdown and explanations to support the length of time needed to complete each activity.

(ii) A description of the material process flow rates, system operating parameters, and other information that the owner or operator shall monitor and record during the shutdown period.

(iii) Identification of the control technologies or strategies to be utilized.

(iv) A description of the physical conditions present during shutdown periods that prevent the controls from being effective.

(v) A reasonably precise estimate as to when physical conditions will have reached a state that allows for the effective control of emissions.

(2) The duration of a shutdown, as measured from the time the furnace operations drop below 25% of the permitted production capacity or fuel use capacity to when all emissions from the furnace cease, may not exceed 20 days.

(3) If you are the owner or operator of an affected unit, you shall operate the emissions control system whenever technologically feasible during shutdown to minimize emissions.

(f) *Idling requirements.* (1) If you are the owner or operator of an affected unit, you shall operate the emissions control system whenever technologically feasible during idling to minimize emissions.

(2) If you are the owner or operator of an affected unit, your NO_X emissions during idling may not exceed the amount calculated using the following equation: Pounds per day emissions limit of NO_X = (Applicable NO_X emissions limit specified in paragraph (c) of this section expressed in pounds per ton of glass produced) × (Furnace permitted production capacity in tons of glass produced per day).

(3) To demonstrate compliance with the alternative daily NO_X emissions limit identified in paragraph (f)(2) of this section during periods of idling, the owners or operators of an affected unit shall maintain records consistent with paragraph (h)(3) of this section.

(g) *Testing and monitoring requirements.* (1) If you own or operate an affected unit subject to the NO_X emissions limits under paragraph (c) of this section you must conduct performance tests, on an annual basis, in accordance with the applicable reference test methods of 40 CFR part 60, appendix A–4, any alternative test method approved by the EPA as of June 5, 2023, under 40 CFR 59.104(f), 60.8(b)(3), 61.13(h)(1)(ii), 63.7(e)(2)(ii), or 65.158(a)(2) and available at the EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by the EPA through notice-and-comment rulemaking. The annual performance test does not have to be performed during the ozone season. Owners or operators of affected units must calculate and record the 30-day rolling average emissions rate of NO_X as the total of all hourly emissions data for an affected unit in the preceding 30 days, divided by the total tons of glass produced in that affected unit during the same 30-day period. Direct measurement or material balance using good engineering practice shall be used to determine the amount of glass produced during the performance test.

The rate of glass produced is defined as the weight of glass pulled from the affected unit during the performance test divided by the number of hours taken to perform the performance test.

(2) If you are the owner or operator of an affected unit subject to the NO_X emissions limits under paragraph (c)(1) of this section and are operating a NO_X CEMS that monitors NO_X emissions from the affected unit, you may use the CEMS data in lieu of the annual performance tests and parametric monitoring required under this section. You must meet the following requirements for using CEMS to monitor NO_X emissions:

(i) You shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring NO_X emissions and either oxygen (O_2) or carbon dioxide (CO_2).

(ii) The CEMS shall be operated and data recorded during all periods of operation during the ozone season of the affected unit except for CEMS breakdowns and repairs. Data shall be recorded during calibration checks and zero and span adjustments.

(iii) The 1-hour average NO_X emissions rates measured by the CEMS shall be expressed in terms of lbs/ton of glass and shall be used to calculate the average emissions rates to demonstrate compliance with the applicable emissions limits in this section.

(iv) The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(v) When NO_X emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emissions data will be obtained by using standby monitoring systems, Method 7 of 40 CFR part 60, appendix A–4, Method 7A of 40 CFR part 60, appendix A–4, or other approved reference methods to provide emissions data for a minimum of 75 percent of the operating hours in each affected unit operating day, in at least 22 out of 30 successive operating days.

(3) If you are the owner or operator of an affected unit not operating NO_X CEMS, you must conduct an initial performance test before the 2026 ozone season to establish appropriate indicator ranges for operating parameters and continuously monitor those operator parameters consistent with the requirements of paragraphs (g)(3)(i) through (iv) of this section.

(i) You must monitor and record stack exhaust gas flow rate, hourly glass production, and stack exhaust gas temperature during the initial performance test and subsequent annual performance tests to demonstrate continuous compliance with your NO_X emissions limits.

(ii) You must use the stack exhaust gas flow rate, hourly glass production, and stack exhaust gas temperature during the initial performance test and subsequent annual performance tests as NO_X CEMS indicators to demonstrate continuous compliance and establish a site-specific indicator ranges for these operating parameters.

(iii) You must repeat the performance test annually to reassess and adjust the site-specific operating parameter indicator ranges in accordance with the results of the performance test.

(iv) You must report and include your ongoing site-specific operating parameter data in the annual reports required under paragraph (h) of this section and semi-annual title V monitoring reports to the relevant permitting authority.

(4) If you are the owner or operator of an affected unit seeking to comply with the requirements for startup under paragraph (d) of this section or shutdown under paragraph (e) of this section in lieu of the applicable emissions limit under paragraph (c) of this section, you must monitor material process flow rates, fuel throughput, oxidant flow rate, and the selected system operating parameters in accordance with paragraphs (d)(1)(ii) and (e)(1)(ii) of this section.

(h) *Recordkeeping requirements.* (1) If you are the owner or operator of an affected unit, you shall maintain records of the following information for each day the affected unit operates:

(i) Calendar date;

(ii) The average hourly NO_X emissions rates measured or predicted;

(iii) The 30-day average NO_X emissions rates calculated at the end of each affected unit operating day from the measured or predicted hourly NO_X emissions rates for the preceding 30 operating days;

(iv) Identification of the affected unit operating days when the calculated 30-day average NO_X emissions rates are in excess of the applicable site-specific NO_X emissions limit with the reasons for such excess emissions as well as a description of corrective actions taken;

(v) Identification of the affected unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(vi) Identification of the times when emissions data have been excluded from the calculation of average emissions rates and the reasons for excluding data;

(vii) If a CEMS is used to verify compliance:

(A) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(B) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3 in appendix B to 40 CFR part 60; and

(C) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of 40 CFR part 60, appendix F;

(D) Operating parameters required under paragraph (g) to demonstrate compliance during the ozone season;

(viii) Each fuel type, usage, and heat content; and

(ix) Glass production rate.

(2) If you are the owner or operator of an affected unit, you shall maintain all records necessary to demonstrate compliance with the startup and shutdown requirements in paragraphs (d) and (e) of this section, including but not limited to records of material process flow rates, system operating parameters, the duration of each startup and shutdown period, fuel throughput, oxidant flow rate, and any additional records necessary to determine whether the stoichiometric ratio of the primary furnace combustion system exceeded 5 percent excess oxygen during startup.

(3) If you are the owner or operator of an affected unit, you shall maintain records of daily NO_X emissions in pounds per day for purposes of determining compliance with the applicable emissions limit for idling periods under paragraph (f)(2) of this section. Each owner or operator shall also record the duration of each idling period.

(i) *Reporting requirements.* (1) If you are the owner or operator of an affected unit, you must submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in § 52.40(g) within 60 days after the date of completing each performance test required by this section.

(2) If you are the owner or operator of an affected unit, you are required to submit excess emissions reports for any excess emissions that occurred during the reporting period. Excess emissions are defined as any calculated 30-day rolling average NO_X emissions rate that exceeds the applicable emissions limit in paragraph (c) of this section. Excess emissions reports must be submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section following the procedures specified in § 52.40(g).

(3) If you own or operate an affected unit, you shall submit an annual report in PDF format to the EPA by January 30th of each year via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section. Annual reports shall be submitted following the procedures in § 52.40(g). The report shall include records all records required by paragraph (g) of this section, including record of CEMS data or operating parameters to demonstrate continuous compliance the applicable emissions limits under paragraphs (c) of this section.

(j) *Initial notification requirements for existing affected units.* (1) The requirements of this paragraph (j) apply to the owner or operator of an existing affected unit.

(2) The owner or operator of an existing affected unit that emits or has a potential to emit greater than 100 tons per year or greater as of August 4, 2023, shall notify the Administrator via the CEDRI or analogous electronic submission system provided by the EPA that the unit is subject to this section. The notification, which shall be submitted not later than June 23, 2023, shall be submitted in PDF format to the EPA via CEDRI, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The notification shall provide the following information:

(i) The name and address of the owner or operator;

(ii) The address (*i.e.,* physical location) of the affected unit;

(iii) An identification of the relevant standard, or other requirement, that is the basis for the notification and the unit's compliance date; and

(iv) A brief description of the nature, size, design, and method of operation of the facility and an identification of the types of emissions points (units) within the facility subject to the relevant standard.

§ 52.45 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, the Pulp, Paper, and Paperboard Mills Industries, Metal Ore Mining, and the Iron and Steel and Ferroalloy Manufacturing Industries?

(a) *Definitions.* All terms not defined in this paragraph (a) shall have the meaning given to them in the Act and in subpart A of 40 CFR part 60.

Affected unit means an industrial boiler meeting the applicability criteria of this section.

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled.

Coal means ''coal'' as defined in 40 CFR 60.41b.

Distillate oil means ''distillate oil'' as defined in 40 CFR 60.41b.

Maximum heat input capacity means means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Natural gas means ''natural gas'' as defined in 40 CFR 60.41.

Operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Residual oil means ''residual oil'' as defined in 40 CFR 60.41c.

(b) *Applicability.* (1) The requirements of this section apply to each new or existing boiler with a design capacity of 100 mmBtu/hr or greater that receives 90% or more of its heat input from coal, residual oil, distillate oil, natural gas, or combinations of these fuels in the previous ozone season, is located at sources that are within the Basic Chemical Manufacturing industry, the Petroleum and Coal Products Manufacturing industry, the Pulp, Paper, and Paperboard industry, the Metal Ore Mining industry, and the Iron and Steel and Ferroalloys Manufacturing industry and which is located within any of the States listed in § 52.40(c)(2), including Indian country located within the borders of any such State(s). The requirements of this section do not apply to an emissions unit that meets the requirements for a low-use exemption as provided in paragraph (b)(2) of this section.

(2) If you are the owner or operator of a boiler meeting the applicability criteria of paragraph (b)(1) of this section that operates less than 10% per year on an hourly basis, based on the three most recent years of use and no more than 20% in any one of the three years, you are exempt from meeting the emissions limits of this section and are only subject to the recordkeeping and reporting requirements of paragraph (f)(2) of this section.

(i) If you are the owner or operator of an affected unit that exceeds the 10% per year hour of operation over three years or the 20% hours of operation per year criteria, you can no longer comply via the low-use exemption provisions and must meet the applicable emissions limits and other applicable provisions as soon as possible but not later than one year from the date eligibility as a low-use boiler was negated by exceedance of the low-use boiler criteria.

(ii) [Reserved]

(c) *Emissions limitations.* If you are the owner or operator of an affected unit, you must meet the following emissions limitations on a 30-day rolling average basis during the 2026 ozone season and in each ozone season thereafter:

(1) Coal-fired industrial boilers: 0.20 lbs NO_X/mmBtu;

(2) Residual oil-fired industrial boilers: 0.20 lbs NO_X/mmBtu;

(3) Distillate oil-fired industrial boilers: 0.12 lbs NO_X/mmBtu;

(4) Natural gas-fired industrial boilers: 0.08 lbs NO_X/mmBtu; and

(5) Boilers using combinations of fuels listed in paragraphs (c)(1) through (4) of this section: such units shall comply with a NO_X emissions limit derived by summing the products of each fuel's heat input and respective emissions limit and dividing by the sum of the heat input contributed by each fuel.

(d) *Testing and monitoring requirements.* (1) If you are the owner or operator of an affected unit, you shall conduct an initial compliance test as described in 40 CFR 60.8 using the continuous system for monitoring NO_X specified by EPA Test Method 7E of 40 CFR part 60, appendix A–4, to determine compliance with the emissions limits for NO_X identified in paragraph (c) of this section. In lieu of the timing of the compliance test described in 40 CFR 60.8(a), you shall conduct the test within 90 days from the installation of the pollution control equipment used to comply with the NO_X emissions limits in paragraph (c) of this section and no later than May 1, 2026.

(i) For the initial compliance test, you shall monitor NO_X emissions from the affected unit for 30 successive operating days and the 30-day average emissions rate will be used to determine compliance with the NO_X emissions limits in paragraph (c) of this section. You shall calculate the 30-day average emission rate as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(ii) You are not required to conduct an initial compliance test if the affected unit is subject to a pre-existing, federally enforceable requirement to monitor its NO_X emissions using a

CEMS in accordance with 40 CFR 60.13 or 40 CFR part 75.

(2) If you are the owner or operator of an affected unit with a heat input capacity of 250 mmBTU/hr or greater, you are subject to the following monitoring requirements:

(i) You shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring NO_X emissions and either oxygen (O_2) or carbon dioxide (CO_2), unless the Administrator has approved a request from you to use an alternative monitoring technique under paragraph (d)(2)(vii) of this section. If you have previously installed a NO_X emissions rate CEMS to meet the requirements of 40 CFR 60.13 or 40 CFR part 75 and continue to meet the ongoing requirements of 40 CFR 60.13 or 40 CFR part 75, that CEMS may be used to meet the monitoring requirements of this section.

(ii) You shall operate the CEMS and record data during all periods of operation during the ozone season of the affected unit except for CEMS breakdowns and repairs. You shall record data during calibration checks and zero and span adjustments.

(iii) You shall express the 1-hour average NO_X emissions rates measured by the CEMS in terms of lbs/mmBtu heat input and shall be used to calculate the average emissions rates under paragraph (c) of this section.

(iv) Following the date on which the initial compliance test is completed, you shall determine compliance with the applicable NO_X emissions limit in paragraph (c) of this section during the ozone season on a continuous basis using a 30-day rolling average emissions rate unless you monitor emissions by means of an alternative monitoring procedure approved pursuant to paragraph (d)(2)(vii) of this section. You shall calculate a new 30-day rolling average emissions rate for each operating day as the average of all the hourly NO_X emissions data for the preceding 30 operating days.

(v) You shall follow the procedures under 40 CFR 60.13 for installation, evaluation, and operation of the continuous monitoring systems. Additionally, you shall use a span value of 1000 ppm NO_X for affected units combusting coal and span value of 500 ppm NO_X for units combusting oil or gas. As an alternative to meeting these span values, you may elect to use the NO_X span values determined according to section 2.1.2 in appendix A to 40 CFR part 75.

(vi) When you are unable to obtain NO_X emissions data because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, you will obtain emissions data by using standby monitoring systems, Method 7 of 40 CFR part 60, appendix A–4, Method 7A of 40 CFR part 60, appendix A–4, or other approved reference methods to provide emissions data for a minimum of 75 percent of the operating hours in each affected unit operating day, in at least 22 out of 30 successive operating days.

(vii) You may delay installing a CEMS for NO_X until after the initial performance test has been conducted. If you demonstrate during the performance test that emissions of NO_X are less than 70 percent of the applicable emissions limit in paragraph (c) of this section, you are not required to install a CEMS for measuring NO_X. If you demonstrate your affected unit emits less than 70 percent of the applicable emissions limit chooses to not install a CEMS, you must submit a written request to the Administrator that documents the results of the initial performance test and includes an alternative monitoring procedure that will be used to track compliance with the applicable NO_X emissions limit(s) in paragraph (c) of this section. The Administrator may consider the request and, following public notice and comment, may approve the alternative monitoring procedure with or without revision, or disapprove the request. Upon receipt of a disapproved request, you will have one year to install a CEMS.

(3) If you are the owner or operator of an affected unit with a heat input capacity less than 250 mmBTU/hr, you must monitor NO_X emission via the requirements of paragraph (e)(1) of this section or you must monitor NO_X emissions by conducting an annual test in conjunction with the implementation of a monitoring plan meeting the following requirements:

(i) You must conduct an initial performance test over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the NO_X emission standards under paragraph (c) of this section using Method 7, 7A, or 7E of appendix A–4 to 40 CFR part 60, Method 320 of appendix A to 40 CFR part 63, or other approved reference methods.

(ii) You must conduct annual performance tests once per calendar year to demonstrate compliance with the NO_X emission standards under paragraph (c) of this section over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, or 7E of appendix A–4 to 40 CFR part 60, Method 320 of appendix A to 40 CFR part 63, or other approved reference methods. The annual performance test must be conducted before the affected units operates more than 400 hours in a given year.

(iii) You must develop and comply with a monitoring plan that relates the operational parameters to emissions of the affected unit. The owner or operator of each affected unit shall develop a monitoring plan that identifies the operating conditions of the affected unit to be monitored and the records to be maintained in order to reliably predict NO_X emissions and determine compliance with the applicable emissions limits of this section on a continuous basis. You shall include the following information in the plan:

(A) You shall identify the specific operating parameters to be monitored and the relationship between these operating parameters and the applicable NO_X emission rates. Operating parameters of the affected unit include, but are not limited to, the degree of staged combustion (*i.e.,* the ratio of primary air to secondary and/or tertiary air) and the level of excess air (*i.e.,* flue gas O_2 level).

(B) You shall include the data and information used to identify the relationship between NO_X emission rates and these operating conditions.

(C) *You shall identify:* how these operating parameters, including steam generating unit load, will be monitored on an hourly basis during periods of operation of the affected unit; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating parameters will be representative and accurate; and the type and format of the records of these operating parameters, including steam generating unit load, that you will maintain.

(4) You shall submit the monitoring plan to the EPA via the CEDRI reporting system, and request that the relevant permitting agency incorporate the monitoring plan into the facility's title V permit.

(e) *Recordkeeping requirements.* (1) If you are the owner or operator of an affected unit, which is not a low-use boiler, you shall maintain records of the following information for each day the affected unit operates during the ozone season:

(i) Calendar date;

(ii) The average hourly NO_X emissions rates (expressed as lbs NO_2/mmBtu heat input) measured or predicted;

(iii) The 30-day average NO_X emissions rates calculated at the end of each affected unit operating day from the measured or predicted hourly NO_X emissions rates for the preceding 30 steam generating unit operating days;

(iv) Identification of the affected unit operating days when the calculated 30-day rolling average NO_X emissions rates are in excess of the applicable NO_X emissions limit in paragraph (c) of this section with the reasons for such excess emissions as well as a description of corrective actions taken;

(v) Identification of the affected unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(vi) Identification of the times when emissions data have been excluded from the calculation of average emissions rates and the reasons for excluding data;

(vii) Identification of ''F'' factor used for calculations, method of determination, and type of fuel combusted;

(viii) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(ix) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3 in appendix B to 40 CFR part 60;

(x) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of 40 CFR part 60, appendix F; and

(xi) The type and amounts of each fuel combusted.

(2) If you are the owner or operator of an affected unit complying as a low-use boiler, you must maintain the following records consistent with the requirements of § 52.40(g):

(i) Identification and location of the boiler;

(ii) Nameplate capacity;

(iii) The fuel or fuels used by the boiler;

(iv) For each operating day, the type and amount of fuel combusted, and the date and total number of hours of operation; and

(v) the annual hours of operation for each of the prior 3 years, and the 3-year average hours or operation.

(f) *Reporting requirements.* (1) If you are the owner or operator of an affected unit, you must submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in § 52.40(g) within 60 days after the date of completing each performance test required by this section.

(2) If you are the owner or operator of an affected unit, you are required to submit excess emissions reports for any excess emissions that occurred during the reporting period. Excess emissions are defined as any calculated 30-day rolling average NO_X emissions rate, as determined under paragraph (e)(1)(iii) of this section, that exceeds the applicable emissions limit in paragraph (c) of this section. Excess emissions reports must be submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section following the procedures specified in § 52.40(g).

(3) If you are the owner or operator an affected unit subject to the continuous monitoring requirements for NO_X under paragraph (d) of this section, you shall submit reports containing the information recorded under paragraph (d) of this section as described in paragraph (e)(1) of this section. You shall submit compliance reports for continuous monitoring in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section following the procedures specified in § 52.40(g).

(4) If you are the owner or operator of an affected unit, you shall submit an annual report in PDF format to the EPA by January 30th of each year via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section. Annual reports shall be submitted following the procedures in § 52.40(g).

§ 52.46 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from Municipal Waste Combustors?

(a) *Definitions.* All terms not defined in this paragraph (a) shall have the meaning given them in the Act and in subpart A of 40 CFR part 60.

Affected unit means a municipal waste combustor meeting the applicability criteria of this section.

Chief facility operator means the person in direct charge and control of the operation of a municipal waste combustor and who is responsible for daily onsite supervision, technical direction, management, and overall performance of the facility.

Mass burn refractory municipal waste combustor means a field-erected combustor that combusts municipal solid waste in a refractory wall furnace. Unless otherwise specified, this includes combustors with a cylindrical rotary refractory wall furnace.

Mass burn rotary waterwall municipal waste combustor means a field-erected combustor that combusts municipal solid waste in a cylindrical rotary waterwall furnace or on a tumbling-tile grate.

Mass burn waterwall municipal waste combustor means a field-erected combustor that combusts municipal solid waste in a waterwall furnace.

Municipal waste combustor, MWC, or *municipal waste combustor unit* means:

(i) Means any setting or equipment that combusts solid, liquid, or gasified MSW including, but not limited to, field-erected incinerators (with or without heat recovery), modular incinerators (starved-air or excess-air), boilers (*i.e.,* steam-generating units), furnaces (whether suspension-fired, grate-fired, mass-fired, air curtain incinerators, or fluidized bed-fired), and pyrolysis/combustion units. Municipal waste combustors do not include pyrolysis/combustion units located at plastics/rubber recycling units. Municipal waste combustors do not include internal combustion engines, gas turbines, or other combustion devices that combust landfill gases collected by landfill gas collection systems.

(ii) The boundaries of a MWC are defined as follows. The MWC unit includes, but is not limited to, the MSW fuel feed system, grate system, flue gas system, bottom ash system, and the combustor water system. The MWC boundary starts at the MSW pit or hopper and extends through:

(A) The combustor flue gas system, which ends immediately following the heat recovery equipment or, if there is no heat recovery equipment, immediately following the combustion chamber;

(B) The combustor bottom ash system, which ends at the truck loading station or similar ash handling equipment that transfer the ash to final disposal, including all ash handling systems that are connected to the bottom ash handling system; and

(C) The combustor water system, which starts at the feed water pump and ends at the piping exiting the steam drum or superheater.

(iii) The MWC unit does not include air pollution control equipment, the stack, water treatment equipment, or the turbine generator set.

Municipal waste combustor unit capacity means the maximum charging rate of a municipal waste combustor unit expressed in tons per day of municipal solid waste combusted, calculated according to the procedures under paragraph (e)(4) of this section.

Shift supervisor means the person who is in direct charge and control of the operation of a municipal waste combustor and who is responsible for onsite supervision, technical direction, management, and overall performance of the facility during an assigned shift.

(b) *Applicability.* The requirements of this section apply to each new or existing municipal waste combustor unit with a combustion capacity greater than 250 tons per day (225 megagrams per day) of municipal solid waste and which is located within any of the States listed in § 52.40(c)(2), including Indian country located within the borders of any such State(s).

(c) *Emissions limitations.* If you are the owner or operator of an affected unit, you must meet the following emissions limitations at all times, except during startup and shutdown, on a 30-day rolling average basis during the 2026 ozone season and in each ozone season thereafter:

(1) 110 ppmvd at 7 percent oxygen on a 24-hour block averaging period; and

(2) 105 ppmvd at 7 percent oxygen on a 30-day rolling averaging period.

(d) *Startup and shutdown requirements.* If you are the owner or operator of an affected unit, you must comply with the following requirements during startup and shutdown:

(1) During periods of startup and shutdown, you shall meet the following emissions limits at stack oxygen content:

(i) 110 ppmvd at stack oxygen content on a 24-hour block averaging period; and

(ii) 105 ppmvd at stack oxygen content on a 30-day rolling averaging period.

(2) Duration of startup and shutdown, periods are limited to 3 hours per occurrence.

(3) The startup period commences when the affected unit begins the continuous burning of municipal solid waste and does not include any warmup period when the affected unit is combusting fossil fuel or other nonmunicipal solid waste fuel, and no municipal solid waste is being fed to the combustor.

(4) Continuous burning is the continuous, semicontinuous, or batch feeding of municipal solid waste for purposes of waste disposal, energy production, or providing heat to the combustion system in preparation for waste disposal or energy production. The use of municipal solid waste solely to provide thermal protection of the grate or hearth during the startup period when municipal solid waste is not being fed to the grate is not considered to be continuous burning.

(5) The owner and operator of an affected unit shall minimize NO_X emissions by operating and optimizing the use of all installed pollution control technology and combustion controls consistent with the technological limitations, manufacturers' specifications, good engineering and maintenance practices, and good air pollution control practices for minimizing emissions (as defined in 40 CFR 60.11(d)) for such equipment and the unit at all times the unit is in operation.

(e) *Testing and monitoring requirements.* (1) If you are the owner or operator of an affected unit, you shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring the oxygen or carbon dioxide content of the flue gas at each location where NO_X are monitored and record the output of the system. You shall comply with the following test procedures and test methods:

(i) You shall use a span value of 25 percent oxygen for the oxygen monitor or 20 percent carbon dioxide for the carbon dioxide monitor;

(ii) You shall install, evaluate, and operate the CEMS in accordance with 40 CFR 60.13;

(iii) You shall complete the initial performance evaluation no later than 180 days after the date of initial startup of the affected unit, as specified under 40 CFR 60.8;

(iv) You shall operate the monitor in conformance with Performance Specification 3 in 40 CFR part 60, appendix B, except for section 2.3 (relative accuracy requirement);

(v) You shall operate the monitor in accordance with the quality assurance procedures of 40 CFR part 60, appendix F, except for section 5.1.1 (relative accuracy test audit); and

(vi) If you select carbon dioxide for use in diluent corrections, you shall establish the relationship between oxygen and carbon dioxide levels during the initial performance test according to the following procedures and methods:

(A) This relationship may be reestablished during performance compliance tests; and

(B) You shall submit the relationship between carbon dioxide and oxygen concentrations to the EPA as part of the initial performance test report and as part of the annual test report if the relationship is reestablished during the annual performance test.

(2) If you are the owner or operator of an affected unit, you shall use the following procedures and test methods to determine compliance with the NO_X emission limits in paragraph (c) of this section:

(i) If you are not already operating a CEMS in accordance with 40 CFR 60.13, you shall conduct an initial performance test for nitrogen oxides consistent with 40 CFR 60.8.

(ii) You shall install and operate the NO_X CEMS according to Performance Specification 2 in 40 CFR part 60, appendix B, and shall follow the requirements of 40 CFR 60.58b(h)(10).

(iii) Quarterly accuracy determinations and daily calibration drift tests for the CEMS shall be performed in accordance with Procedure 1 in 40 CFR part 60, appendix F.

(iv) When NO_X continuous emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained using other monitoring systems as approved by the EPA or EPA Reference Method 19 in 40 CFR part 60, appendix A–7, to provide, as necessary, valid emissions data for a minimum of 90 percent of the hours per calendar quarter and 95 percent of the hours per calendar year the unit is operated and combusting municipal solid waste.

(v) You shall use EPA Reference Method 19, section 4.1, in 40 CFR part 60, appendix A–7, for determining the daily arithmetic average NO_X emissions concentration.

(A) You may request that compliance with the NO_X emissions limit be determined using carbon dioxide measurements corrected to an equivalent of 7 percent oxygen. The relationship between oxygen and carbon dioxide levels for the affected unit shall be established as specified in paragraph (e)(1)(vi) of this section.

(B) [Reserved]

(vi) At a minimum, you shall obtain valid CEMS hourly averages for 90 percent of the operating hours per calendar quarter and for 95 percent of the operating hours per calendar year that the affected unit is combusting municipal solid waste:

(A) At least 2 data points per hour shall be used to calculate each 1-hour arithmetic average.

(B) Each NO_X 1-hour arithmetic average shall be corrected to 7 percent oxygen on an hourly basis using the 1-hour arithmetic average of the oxygen (or carbon dioxide) continuous emissions monitoring system data.

(vii) The 1-hour arithmetic averages section shall be expressed in parts per million by volume (dry basis) and used to calculate the 24-hour daily arithmetic average concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under 40 CFR 60.13(e)(2).

(viii) All valid CEMS data must be used in calculating emissions averages even if the minimum CEMS data requirements of paragraph (e)(2)(iv) of this section are not met.

(ix) The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the CEMS. The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the municipal waste combustor unit.

(3) If you are the owner or operator of an affected unit, you must determine compliance with the startup and shutdown requirements of paragraph (d) of this section by following the requirements in paragraphs (e)(3)(i) and (ii) of this section:

(i) You can measure CEMS data at stack oxygen content. You can dismiss or exclude CEMS data from compliance calculations, but you shall record and report CEMS data in accordance with the provisions of 40 CFR 60.59b(d)(7).

(ii) You shall determine compliance with the NO_X mass loading emissions limitation for periods of startup and shutdown by calculating the 24-hour average of all hourly average NO_X emissions concentrations from continuous emissions monitoring systems.

(A) You shall perform this calculations using stack flow rates derived from flow monitors, for all the hours during the 3-hour startup or shutdown period and the remaining 21 hours of the 24-hour period.

(B) [Reserved]

(4) If you are the owner or operator of an affected unit, you shall calculate municipal waste combustor unit capacity using the following procedures:

(i) For municipal waste combustor units capable of combusting municipal solid waste continuously for a 24-hour period, municipal waste combustor unit capacity shall be calculated based on 24 hours of operation at the maximum charging rate. The maximum charging rate shall be determined as specified in paragraphs (e)(4)(i)(A) and (B) of this section as applicable.

(A) For combustors that are designed based on heat capacity, the maximum charging rate shall be calculated based on the maximum design heat input capacity of the unit and a heating value of 12,800 kilojoules per kilogram for combustors firing refuse-derived fuel and a heating value of 10,500 kilojoules per kilogram for combustors firing municipal solid waste that is not refuse-derived fuel.

(B) For combustors that are not designed based on heat capacity, the maximum charging rate shall be the maximum design charging rate.

(ii) For batch feed municipal waste combustor units, municipal waste combustor unit capacity shall be calculated as the maximum design amount of municipal solid waste that can be charged per batch multiplied by the maximum number of batches that could be processed in a 24-hour period. The maximum number of batches that could be processed in a 24-hour period is calculated as 24 hours divided by the design number of hours required to process one batch of municipal solid waste, and may include fractional batches (*e.g.,* if one batch requires 16 hours, then 24/16, or 1.5 batches, could be combusted in a 24-hour period). For batch combustors that are designed based on heat capacity, the design heating value of 12,800 kilojoules per kilogram for combustors firing refuse-derived fuel and a heating value of 10,500 kilojoules per kilogram for combustors firing municipal solid waste that is not refuse-derived fuel shall be used in calculating the municipal waste combustor unit capacity in megagrams per day of municipal solid waste.

(f) *Recordkeeping requirements.* If you are the owner or operator of an affected unit, you shall maintain records of the following information, as applicable, for each affected unit consistent with the requirements of § 52.40(g).

(1) The calendar date of each record.

(2) The emissions concentrations and parameters measured using continuous monitoring systems.

(i) All 1-hour average NO_X emissions concentrations.

(ii) The average concentrations and percent reductions, as applicable, including all 24-hour daily arithmetic average NO_X emissions concentrations.

(3) Identification of the calendar dates and times (hours) for which valid hourly NO_X emissions, including reasons for not obtaining the data and a description of corrective actions taken.

(4) Identification of each occurrence that NO_X emissions data, or operational data (*i.e.,* unit load) have been excluded from the calculation of average emissions concentrations or parameters, and the reasons for excluding the data.

(5) The results of daily drift tests and quarterly accuracy determinations for CEMS, as required under 40 CFR part 60, appendix F, Procedure 1.

(6) The following records:

(i) Records showing the names of the municipal waste combustor chief facility operator, shift supervisors, and control room operators who have been provisionally certified by the American Society of Mechanical Engineers or an equivalent State-approved certification program as required by 40 CFR 60.54b(a) including the dates of initial and renewal certifications and documentation of current certification;

(ii) Records showing the names of the municipal waste combustor chief facility operator, shift supervisors, and control room operators who have been fully certified by the American Society of Mechanical Engineers or an equivalent State-approved certification program as required by 40 CFR 60.54b(b) including the dates of initial and renewal certifications and documentation of current certification;

(iii) Records showing the names of the municipal waste combustor chief facility operator, shift supervisors, and control room operators who have completed the EPA municipal waste combustor operator training course or a State-approved equivalent course as required by 40 CFR 60.54b(d) including documentation of training completion; and

(iv) Records of when a certified operator is temporarily off site. Include two main items:

(A) If the certified chief facility operator and certified shift supervisor are off site for more than 12 hours, but for 2 weeks or less, and no other certified operator is on site, record the dates that the certified chief facility operator and certified shift supervisor were off site.

(B) When all certified chief facility operators and certified shift supervisors are off site for more than 2 weeks and no other certified operator is on site, keep records of four items:

(*1*) Time of day that all certified persons are off site.

(*2*) The conditions that cause those people to be off site.

(*3*) The corrective actions taken by the owner or operator of the affected unit to ensure a certified chief facility operator or certified shift supervisor is on site as soon as practicable.

(*4*) Copies of the reports submitted every 4 weeks that summarize the actions taken by the owner or operator of the affected unit to ensure that a certified chief facility operator or certified shift supervisor will be on site as soon as practicable.

(7) Records showing the names of persons who have completed a review of the operating manual as required by 40 CFR 60.54b(f) including the date of the initial review and subsequent annual reviews.

(8) Records of steps taken to minimize emissions during startup and shutdown as required by paragraph (d)(5) of this section.

(g) *Reporting requirements.* (1) If you are the owner or operator of an affected unit, you must submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in § 52.40(g) within 60 days after the date of completing each performance test required by this section.

(2) If you are the owner or operator of an affected unit, you shall submit an annual report in PDF format to the EPA by January 30th of each year via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section. Annual reports shall be submitted following the procedures in § 52.40(g). The report shall include all information required by paragraph (e) of this section, including CEMS data to demonstrate compliance with the applicable emissions limits under paragraph (c) of this section.

Subpart B—Alabama

■ 5. Amend § 52.54 by revising paragraphs (b)(2) and (3) and adding paragraphs (b)(4) and (5) to read as follows:

§ 52.54 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b) * * *

(2) The owner and operator of each source and each unit located in the State of Alabama and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 through 2022. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(ii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's SIP.

(3) The owner and operator of each source and each unit located in the State of Alabama and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's SIP.

(4) Notwithstanding the provisions of paragraphs (b)(2) and (3) of this section, if, at the time of the approval of Alabama's SIP revision described in paragraph (b)(2) or (3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances or CSAPR NO_X Ozone Season Group 3 allowances under subpart EEEEE or GGGGG, respectively, of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of such subpart authorizing the Administrator to complete the allocation and recordation of such allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (b)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State and Indian country within the borders of the State for control periods after 2022) shall continue to apply.

Subpart E—Arkansas

■ 6. Amend § 52.184 by:

■ a. Redesignating paragraphs (a) through (c) as paragraphs (a)(1) through (3);

■ b. In newly redesignated paragraph (a)(2):

■ i. Removing ''2017 and each subsequent year'' and adding in its place ''2017 through 2022''; and

■ ii. Removing the second sentence;

■ c. Revising newly redesignated paragraph (a)(3); and

■ d. Adding paragraphs (a)(4) and (5) and (b).

The revision and additions read as follows:

§ 52.184 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) * * *

(3) The owner and operator of each source and each unit located in the State of Arkansas and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Arkansas' State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii), except to the extent the Administrator's approval is partial or conditional.

(4) Notwithstanding the provisions of paragraph (a)(3) of this section, if, at the time of the approval of Arkansas' SIP revision described in paragraph (a)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (a)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State for control periods after 2022) shall continue to apply.

(b) The owner and operator of each source located in the State of Arkansas and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart F—California

■ 7. Add § 52.284 to read as follows:

§ 52.284 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

The owner and operator of each source located in the State of California and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart O—Illinois

■ 8. Amend § 52.731 by:
■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.731 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Illinois and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart P—Indiana

■ 9. Amend § 52.789 by:
■ a. In paragraph (b)(2), removing ''(b)(2)(iv), except'' and adding in its place ''(b)(2)(ii), except'';
■ b. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ c. Adding paragraph (c).

The addition reads as follows:

§ 52.789 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Indiana and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart S—Kentucky

■ 10. Amend § 52.940 by:
■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.940 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Kentucky and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart T—Louisiana

■ 11. Amend § 52.984 by:
■ a. In paragraph (d)(3), revising the second and third sentences;
■ b. Revising paragraph (d)(4);
■ c. In paragraph (d)(5), adding ''and Indian country within the borders of the State'' after ''in the State''; and
■ d. Adding paragraph (e).

The revision and addition read as follows:

§ 52.984 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(d) * * *

(3) * * * The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Louisiana's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Louisiana's SIP.

(4) Notwithstanding the provisions of paragraph (d)(3) of this section, if, at the time of the approval of Louisiana's SIP revision described in paragraph (d)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

* * * * *

(e) The owner and operator of each source located in the State of Louisiana and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart V—Maryland

■ 12. Amend § 52.1084 by:
■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.1084 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Maryland

and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart X—Michigan

■ 13. Amend § 52.1186 by:
■ a. In paragraph (e)(3), revising the second and third sentences;
■ b. Revising paragraph (e)(4);
■ c. In paragraph (e)(5), adding ''and Indian country within the borders of the State'' after ''in the State''; and
■ d. Adding paragraph (f).

The revision and addition read as follows:

§ 52.1186 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(e) * * *

(3) * * * The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Michigan's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Michigan's SIP.

(4) Notwithstanding the provisions of paragraph (e)(3) of this section, if, at the time of the approval of Michigan's SIP revision described in paragraph (e)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

* * * * *

(f) The owner and operator of each source located in the State of Michigan and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart Y—Minnesota

■ 14. Amend § 52.1240 by adding paragraph (d) to read as follows:

§ 52.1240 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(d)(1) The owner and operator of each source and each unit located in the State of Minnesota and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Minnesota's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Minnesota's SIP.

(2) Notwithstanding the provisions of paragraph (d)(1) of this section, if, at the time of the approval of Minnesota's SIP revision described in paragraph (d)(1) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart Z—Mississippi

■ 15. Amend § 52.1284 by:
■ a. Redesignating paragraphs (a) through (c) as paragraphs (a)(1) through (3);
■ b. In newly redesignated paragraph (a)(2):
■ i. Removing ''2017 and each subsequent year'' and adding in its place ''2017 through 2022''; and
■ ii. Removing the second and third sentences;
■ c. Revising newly redesignated paragraph (a)(3); and
■ d. Adding paragraphs (a)(4) and (5) and (b).

The revision and additions read as follows:

§ 52.1284 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) * * *

(3) The owner and operator of each source and each unit located in the State of Mississippi and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Mississippi's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Mississippi's SIP.

(4) Notwithstanding the provisions of paragraph (a)(3) of this section, if, at the time of the approval of Mississippi's SIP revision described in paragraph (a)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (a)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State and Indian country within the borders of the State for control periods after 2022) shall continue to apply.

(b) The owner and operator of each source located in the State of Mississippi and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart AA—Missouri

■ 16. Amend § 52.1326 by revising paragraph (b)(2) and (3) and adding paragraphs (b)(4) and (5) and (c) to read as follows:

§ 52.1326 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b) * * *

(2) The owner and operator of each source and each unit located in the State of Missouri and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 through 2022. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Missouri's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(ii), except to the extent the Administrator's approval is partial or conditional.

(3) The owner and operator of each source and each unit located in the State of Missouri and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Missouri's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii), except to the extent the Administrator's approval is partial or conditional.

(4) Notwithstanding the provisions of paragraphs (b)(2) and (3) of this section, if, at the time of the approval of Missouri's SIP revision described in paragraph (b)(2) or (3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances or CSAPR NO_X Ozone Season Group 3 allowances under subpart EEEEE or GGGGG, respectively, of part 97 of this chapter to units in the State for a control period in any year, the provisions of such subpart authorizing the Administrator to complete the allocation and recordation of such allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (b)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State for control periods after 2022) shall continue to apply.

(c) The owner and operator of each source located in the State of Missouri and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart DD—Nevada

■ 17. Add § 52.1492 to read as follows:

§ 52.1492 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Nevada and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Nevada's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Nevada's SIP.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Nevada's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within

the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b) The owner and operator of each source located in the State of Nevada and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart FF—New Jersey

■ 18. Amend § 52.1584 by:

■ a. In paragraph (e)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and

■ b. Adding paragraph (f).

The addition reads as follows:

§ 52.1584 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(f) The owner and operator of each source located in the State of New Jersey and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart HH—New York

■ 19. Amend § 52.1684 by:

■ a. In paragraph (b)(3), revising the second and third sentences;

■ b. Revising paragraph (b)(4);

■ c. In paragraph (b)(5), adding ''and Indian country within the borders of the State'' after ''in the State''; and

■ d. Adding paragraph (c).

The revision and addition read as follows:

§ 52.1684 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b) * * *

(3) * * * The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to New York's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to New York's SIP.

(4) Notwithstanding the provisions of paragraph (b)(3) of this section, if, at the time of the approval of New York's SIP revision described in paragraph (b)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

* * * * *

(c) The owner and operator of each source located in the State of New York and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart KK—Ohio

■ 20. Amend § 52.1882 by:

■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and

■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.1882 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Ohio and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart LL—Oklahoma

■ 21. Amend § 52.1930 by:

■ a. Redesignating paragraphs (a) through (c) as paragraphs (a)(1) through (3);

■ b. In newly redesignated paragraph (a)(2):

■ i. Removing ''2017 and each subsequent year'' and adding in its place ''2017 through 2022''; and

■ ii. Removing the second and third sentences;

■ c. Revising newly redesignated paragraph (a)(3); and

■ d. Adding paragraphs (a)(4) and (5) and (b).

The revision and additions read as follows:

§ 52.1930 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) * * *

(3) The owner and operator of each source and each unit located in the State of Oklahoma and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Oklahoma's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Oklahoma's SIP.

(4) Notwithstanding the provisions of paragraph (a)(3) of this section, if, at the time of the approval of Oklahoma's SIP revision described in paragraph (a)(3) of this section, the Administrator has already started recording any allocations

of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (a)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State and Indian country within the borders of the State for control periods after 2022) shall continue to apply.

(b) The owner and operator of each source located in the State of Oklahoma and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart NN—Pennsylvania

■ 22. Amend § 52.2040 by:

■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and

■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.2040 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Pennsylvania and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart SS—Texas

■ 23. Amend § 52.2283 by:

■ a. In paragraph (d)(2):

■ i. Removing ''2017 and each subsequent year'' and adding in its place ''2017 through 2022''; and

■ ii. Removing the second and third sentences;

■ b. Revising paragraph (d)(3); and

■ c. Adding paragraphs (d)(4) and (5) and (e).

The revision and additions read as follows:

§ 52.2283 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(d) * * *

(3) The owner and operator of each source and each unit located in the State of Texas and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Texas' State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Texas' SIP.

(4) Notwithstanding the provisions of paragraph (d)(3) of this section, if, at the time of the approval of Texas' SIP revision described in paragraph (d)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (d)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State and Indian country within the borders of the State for control periods after 2022) shall continue to apply.

(e) The owner and operator of each source located in the State of Texas and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart TT—Utah

■ 24. Add § 52.2356 to read as follows:

§ 52.2356 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Utah and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Utah's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal

Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Utah's SIP.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Utah's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b) The owner and operator of each source located in the State of Utah and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart VV—Virginia

■ 25. Amend § 52.2440 by:
■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.2440 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Virginia and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart XX—West Virginia

■ 26. Amend § 52.2540 by:
■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.2540 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of West Virginia and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart YY—Wisconsin

■ 27. Amend § 52.2587 by:
■ a. In paragraph (e)(2):
■ i. Removing ''2017 and each subsequent year'' and adding in its place ''2017 through 2022''; and
■ ii. Removing the second and third sentences;
■ b. Revising paragraph (e)(3); and
■ c. Adding paragraphs (e)(4) and (5).

The revision and additions read as follows:

§ 52.2587 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(e) * * *

(3) The owner and operator of each source and each unit located in the State of Wisconsin and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Wisconsin's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Wisconsin's SIP.

(4) Notwithstanding the provisions of paragraph (e)(3) of this section, if, at the time of the approval of Wisconsin's SIP revision described in paragraph (e)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (e)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State and Indian country within the borders of the State for control periods after 2022) shall continue to apply.

PART 75—CONTINUOUS EMISSION MONITORING

■ 28. The authority citation for part 75 is revised to read as follows:

Authority: 42 U.S.C. 7401–7671q and 7651k note.

Subpart H—NO_X Mass Emissions Provisions

■ 29. Amend § 75.72 by:
■ a. In paragraph (c)(3), removing ''appendix B of this part'' and adding in its place ''appendix B to this part'';
■ b. In paragraph (e)(1)(ii), removing ''heat input from'' and adding in its place ''heat input rate to'';
■ c. In paragraph (e)(2), removing ''appendix D of this part'' and adding in its place ''appendix D to this part''; and

■ d. Adding paragraph (f).

The addition reads as follows:

§ 75.72 Determination of NO_X mass emissions for common stack and multiple stack configurations.

* * * * *

(f) *Procedures for apportioning hourly NO_X mass emission rate to the unit level.* If the owner or operator of a unit determining hourly NO_X mass emission rate at a common stack under this section is subject to a State or Federal NO_X mass emissions reduction program under subpart GGGGG of part 97 of this chapter or under a state implementation plan approved pursuant to § 52.38(b)(12) of this chapter, then on and after January 1, 2024, the owner or operator shall apportion the hourly NO_X mass emissions rate at the common stack to each unit using the common stack based on the ratio of the hourly heat input rate for each such unit to the total hourly heat input rate for all such units, in conjunction with the appropriate unit and stack operating times, according to the procedures in section 8.5.3 of appendix F to this part.

* * * * *

■ 30. Amend § 75.73 by:

■ a. Revising paragraph (a)(3);

■ b. In paragraph (c)(1), removing ''NO_X emissions'' and adding in its place ''NO_X emissions'';

■ c. Adding a heading to paragraph (c)(2);

■ d. Revising paragraphs (c)(3) and (f)(1) introductory text;

■ e. Removing and reserving paragraph (f)(1)(i)(B);

■ f. In paragraph (f)(1)(ii)(G), removing ''appendix D;'' and adding in its place ''appendix D to this part;'';

■ g. Adding paragraphs (f)(1)(ix) and (x);

■ h. Adding a heading to paragraph (f)(2); and

■ i. Revising paragraph (f)(4).

The revisions and additions read as follows:

§ 75.73 Recordkeeping and reporting.

(a) * * *

(3) For each hour when the unit is operating, NO_X mass emission rate, calculated in accordance with section 8 of appendix F to this part.

* * * * *

(c) * * *

(2) *Monitoring plan updates.* * * *

(3) *Contents of the monitoring plan.* Each monitoring plan shall contain the information in § 75.53(g)(1) in electronic format and the information in § 75.53(g)(2) in hardcopy format. In addition, to the extent applicable, each monitoring plan shall contain the information in § 75.53(h)(1)(i) and (h)(2)(i) in electronic format and the information in § 75.53(h)(1)(ii) and (h)(2)(ii) in hardcopy format. For units using the low mass emissions excepted methodology under § 75.19, the monitoring plan shall include the additional information in § 75.53(h)(4)(i) and (ii). The monitoring plan also shall include a seasonal controls indicator and an ozone season fuel-switching flag.

* * * * *

(f) * * *

(1) *Electronic submission.* The designated representative for an affected unit shall electronically report the data and information in this paragraph (f)(1) and in paragraphs (f)(2) and (3) of this section to the Administrator quarterly, unless the unit has been placed in long-term cold storage (as defined in § 72.2 of this chapter). Each electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter. Each electronic report shall include the information provided in paragraphs (f)(1)(i) through (x) of this section and shall also include the date of report generation. A unit placed into long-term cold storage is exempted from submitting quarterly reports beginning with the calendar quarter following the quarter in which the unit is placed into long-term cold storage, provided that the owner or operator shall submit quarterly reports for the unit beginning with the data from the quarter in which the unit recommences operation (where the initial quarterly report contains hourly data beginning with the first hour of recommenced operation of the unit).

* * * * *

(ix) On and after on January 1, 2024, for a unit subject to subpart GGGGG of part 97 of this chapter or a state implementation plan approved under § 52.38(b)(12) of this chapter and determining NO_X mass emission rate at a common stack, apportioned hourly NO_X mass emission rate for the unit, lb/hr.

(x) On and after January 1, 2024, for a unit that is subject to subpart GGGGG of part 97 of this chapter or a state implementation plan approved under § 52.38(b)(12) of this chapter, that lists coal or a solid coal-derived fuel as a fuel in the unit's monitoring plan under § 75.53 for any portion of the ozone season in the year for which data are being reported, that serves a generator of 100 MW or larger nameplate capacity, and that is not a circulating fluidized bed boiler, provided that through December 31, 2029, the requirements under this paragraph (f)(1)(x) shall apply to a unit in a given calendar year only if the unit also was equipped with selective catalytic reduction controls on or before September 30 of the previous year:

(A) Daily NO_X emissions (lbs) for each day of the reporting period;

(B) Daily heat input (mmBtu) for each day of the reporting period;

(C) Daily average NO_X emission rate (lb/mmBtu, rounded to the nearest thousandth) for each day of the reporting period;

(D) Daily NO_X emissions (lbs) exceeding the applicable backstop daily NO_X emission rate for each day of the reporting period;

(E) Cumulative NO_X emissions (tons, rounded to the nearest tenth) exceeding the applicable backstop daily NO_X emission rate during the ozone season; and

(F) Cumulative NO_X emissions (tons, rounded to the nearest tenth) exceeding the applicable backstop daily NO_X emission rate during the ozone season by more than 50 tons, calculated as the remainder of the amount calculated under paragraph (f)(1)(x)(E) of this section minus 50, but not less than zero.

(2) *Verification of identification codes and formulas.* * * *

(4) *Electronic format, method of submission, and explanatory information.* The designated representative shall comply with all of the quarterly reporting requirements in § 75.64(d), (f), and (g).

■ 31. Revise § 75.75 to read as follows:

§ 75.75 Additional ozone season calculation procedures.

(a) The owner or operator of a unit that is required to calculate daily or ozone season heat input shall do so by summing the unit's hourly heat input determined according to the procedures in this part for all hours in which the unit operated during the day or ozone season.

(b) The owner or operator of a unit that is required to determine daily or ozone season NO_X emission rate (in lbs/mmBtu) shall do so by dividing daily or ozone season NO_X mass emissions (in lbs) determined in accordance with this subpart, by daily or ozone season heat input determined in accordance with paragraph (a) of this section.

■ 32. Amend appendix F to part 75 by:

■ a. Adding section 5.3.3;

■ b. In section 8.1.2, revising the introductory text preceding Equation F–25;

■ c. In section 8.4, revising the introductory text, paragraph (a) introductory text (preceding Equation F–27), and paragraph (b) introductory text (preceding Equation F–27a) and adding paragraph (c);

■ d. In section 8.5.2, removing ''the hourly NO_X mass emissions at each unit'' and adding in its place ''hourly NO_X mass emissions at the common stack''; and

■ e. Adding section 8.5.3.

The additions and revisions read as follows:

Appendix F to Part 75—Conversion Procedures

* * * * *

5. Procedures for Heat Input

* * * * *

5.3 Heat Input Summation (for Heat Input Determined Using a Flow Monitor and Diluent Monitor)

* * * * *

5.3.3 Calculate total daily heat input for a unit using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_d = \sum_{h=1}^{24} HI_h t_h$$

(Eq. F-18c)

Where:

HI_d = Total heat input for a unit for the day, mmBtu.

HI_h = Heat input rate for the unit for hour ''h'' from Equation F–15, F–16, F–17, F–18, F–21a, or F–21b to this appendix, mmBtu/hr.

t_h = Unit operating time, fraction of the hour (0.00 to 1.00, in equal increments from one hundredth to one quarter of an hour, at the option of the owner or operator).

h = Designation of a particular hour.

* * * * *

8. Procedures for NO_X Mass Emissions

* * * * *

8.1.2 If NO_X emission rate is measured at a common stack and heat input rate is measured at the unit level, calculate the hourly heat input rate at the common stack according to the following formula:

* * * * *

8.4 Use the following equations to calculate daily, quarterly, cumulative ozone season, and cumulative year-to-date NO_X mass emissions:

(a) When hourly NO_X mass emissions are reported in lb., use Eq. F–27 to this appendix to calculate quarterly, cumulative ozone season, and cumulative year-to-date NO_X mass emissions in tons.

* * * * *

(b) When hourly NO_X mass emission rate is reported in lb/hr, use Eq. F–27a to this appendix to calculate quarterly, cumulative ozone season, and cumulative year-to-date NO_X mass emissions in tons.

* * * * *

(c) To calculate daily NO_X mass emissions for a unit in pounds, use Eq. F–27b to this appendix.

$$M_{(NOX)_d} = \sum_{h=1}^{24} E_{(NOX)_h}\, t_h$$

(Eq. F-27b)

Where:

$M_{(NOX)d}$ = NO_X mass emissions for a unit for the day, pounds.

$E_{(NOX)h}$ = NO_X mass emission rate for the unit for hour ''h'' from Equation F–24a, F–26a, F–26b, or F–28, lb/hr.

t_h = Unit operating time, fraction of the hour (0.00 to 1.00, in equal increments from one hundredth to one quarter of an hour, at the option of the owner or operator).

h = Designation of a particular hour.

* * * * *

8.5.3 Where applicable, the owner or operator of a unit that determines hourly NO_X mass emission rate at a common stack shall apportion hourly NO_X mass emissions rate to the units using the common stack based on the hourly heat input rate, using Equation F–28 to this appendix:

$$E_{(NOX)_i} = E_{(NOX)_{CS}} \left(\frac{t_{CS}}{t_i}\right)\left[\frac{HI_i t_i}{\sum_{i=1}^{n} HI_i t_i}\right]$$

(Eq. F-28)

Where:

$E_{(NOX)i}$ = Apportioned NO_X mass emission rate for the hour for unit ''i'', lb/hr.

$E_{(NOX)CS}$ = NO_X mass emission rate for the hour at the common stack, lb/hr.

HI_i = Heat input rate for the hour for unit ''i'','' from Equation F–15, F–16, F–17, F–18, F–21a, or F–21b to this appendix, mmBtu/hr.

t_i = Operating time for unit ''i'', fraction of the hour (0.00 to 1.00, in equal increments from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CS} = Common stack operating time, fraction of the hour (0.00 to 1.00, in equal increments from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Number of units using the common stack.

i = Designation of a particular unit.

* * * * *

PART 78—APPEAL PROCEDURES

■ 33. The authority citation for part 78 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

■ 34. Amend § 78.1 by:

■ a. In paragraphs (b)(13)(i), (b)(14)(i), (b)(15)(i), (b)(16)(i), and (b)(17)(i), removing ''decision on the'' and adding in its place ''calculation of an'';

■ b. In paragraph (b)(17)(viii), adding ''or (e)'' after ''§ 97.826(d)'';
■ c. In paragraph (b)(17)(ix), adding ''or (e)'' after ''§ 97.811(d)'';
■ d. In paragraph (b)(18)(i), removing ''decision on the'' and adding in its place ''calculation of an''; and
■ e. Revising paragraph (b)(19).

The revision reads as follows:

§ 78.1 Purpose and scope.

* * * * *

(b) * * *

(19) Under subpart GGGGG of part 97 of this chapter:

(i) The calculation of a dynamic trading budget under § 97.1010(a)(4) of this chapter.

(ii) The calculation of an allocation of CSAPR NO_X Ozone Season Group 3 allowances under § 97.1011 or § 97.1012 of this chapter.

(iii) The decision on the transfer of CSAPR NO_X Ozone Season Group 3 allowances under § 97.1023 of this chapter.

(iv) The decision on the deduction of CSAPR NO_X Ozone Season Group 3 allowances under § 97.1024, § 97.1025, or § 97.1026(d) of this chapter.

(v) The correction of an error in an Allowance Management System account under § 97.1027 of this chapter.

(vi) The adjustment of information in a submission and the decision on the deduction and transfer of CSAPR NO_X Ozone Season Group 3 allowances based on the information as adjusted under § 97.1028 of this chapter.

(vii) The finalization of control period emissions data, including retroactive adjustment based on audit.

(viii) The approval or disapproval of a petition under § 97.1035 of this chapter.

* * * * *

PART 97—FEDERAL NO_X BUDGET TRADING PROGRAM, CAIR NO_X AND SO_2 TRADING PROGRAMS, CSAPR NO_X AND SO_2 TRADING PROGRAMS, AND TEXAS SO_2 TRADING PROGRAM

■ 35. The authority citation for part 97 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7426, 7491, 7601, and 7651, *et seq.*

Subpart AAAAA—CSAPR NO_X Annual Trading Program

§ 97.402 [Amended]

■ 36. Amend § 97.402 by:
■ a. In the definition of ''CSAPR NO_X Ozone Season Group 1 Trading Program'', removing ''(b)(2)(i) and (ii), and'' and adding in its place ''(b)(2)(i), and'';
■ b. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and''; and
■ c. In the definition of ''CSAPR NO_X Ozone Season Group 3 Trading Program'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and''.

§ 97.411 [Amended]

■ 37. Amend § 97.411 by:
■ a. In paragraphs (b)(1)(i)(A) and (B), removing ''State, in accordance'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance''; and
■ b. In paragraphs (b)(2)(i)(A) and (B), removing ''Indian country within the borders of a State, in accordance'' and adding in its place ''areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance''.

§ 97.412 [Amended]

■ 38. Amend § 97.412 by:
■ a. In paragraph (a) introductory text, removing ''State, the Administrator'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator'';
■ b. In paragraphs (a)(3)(iii) and (a)(5), adding ''and areas of Indian country within the borders of the State subject to the State's SIP authority'' after ''in the State'';
■ c. In paragraph (a)(10), removing ''State, is allocated'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, is allocated'';
■ d. In paragraph (b) introductory text, removing ''Indian country within the borders of each State, the Administrator'' and adding in its place ''areas of Indian country within the borders of each State not subject to the State's SIP authority, the Administrator''; and
■ e. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority''.

§ 97.426 [Amended]

■ 39. In § 97.426, amend paragraph (c) by:
■ a. Removing ''set forth in'' and adding in its place ''established under''; and
■ b. Removing ''State (or Indian'' and adding in its place ''State (and Indian''.

Subpart BBBBB—CSAPR NO_X Ozone Season Group 1 Trading Program

§ 97.502 [Amended]

■ 40. Amend § 97.502 by:
■ a. In the definition of ''CSAPR NO_X Ozone Season Group 1 Trading Program'', removing ''(b)(2)(i) and (ii), and'' and adding in its place ''(b)(2)(i), and'';
■ b. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and'';
■ c. In the definition of ''CSAPR NO_X Ozone Season Group 3 allowance'':
■ i. Adding ''or (e)'' after ''§ 97.826(d)''; and
■ ii. Adding ''or less'' after ''one ton'';
■ d. In the definition of ''CSAPR NO_X Ozone Season Group 3 Trading Program'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and''; and
■ e. In the definition of ''State'', removing ''(b)(2)(i) and (ii), and'' and adding in its place ''(b)(2)(i), and''.

§ 97.511 [Amended]

■ 41. Amend § 97.511 by:
■ a. In paragraphs (b)(1)(i)(A) and (B), removing ''State, in accordance'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance''; and
■ b. In paragraphs (b)(2)(i)(A) and (B), removing ''Indian country within the borders of a State, in accordance'' and adding in its place ''areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance''.

§ 97.512 [Amended]

■ 42. Amend § 97.512 by:
■ a. In paragraph (a) introductory text, removing ''State, the Administrator'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator'';
■ b. In paragraphs (a)(3)(iii) and (a)(5), adding ''and areas of Indian country within the borders of the State subject to the State's SIP authority'' after ''in the State'';
■ c. In paragraph (a)(10), removing ''State, is allocated'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, is allocated'';
■ d. In paragraph (b) introductory text, removing ''Indian country within the borders of each State, the Administrator'' and adding in its place ''areas of Indian country within the borders of each State not subject to the

State's SIP authority, the Administrator''; and

■ e. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority''.

■ 43. Amend § 97.526 by:

■ a. In paragraph (c):

■ i. Removing ''set forth in'' and adding in its place ''established under''; and

■ ii. Removing ''State (or Indian'' and adding in its place ''State (and Indian'';

■ b. In paragraph (d)(1) introductory text, removing ''§ 52.38(b)(2)(i) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(i)(A) of this chapter (and'';

■ c. In paragraph (d)(1)(ii), removing ''except a State listed in § 52.38(b)(2)(i)'' and adding in its place ''listed in § 52.38(b)(2)(ii)'';

■ d. In paragraph (d)(1)(iv), removing ''§ 52.38(b)(2)(iii) or (iv) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(ii) of this chapter (and'';

■ e. Revising paragraph (d)(2)(i);

■ f. In paragraph (d)(2)(ii), removing ''§ 52.38(b)(2)(v) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(iii)(A) of this chapter (and'';

■ g. Adding paragraph (d)(2)(iii);

■ h. In paragraph (e)(1), removing ''§ 52.38(b)(2)(ii) of this chapter (or Indian'' and adding in its place ''§ 52.38(b)(2)(i)(B) of this chapter (and Indian'';

■ i. In paragraph (e)(2), removing ''§ 52.38(b)(2)(iv) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(ii)(B) of this chapter (and''; and

■ j. Adding paragraph (e)(3).

The revisions and additions read as follows:

§ 97.526 Banking and conversion.

* * * * *

(d) * * *

(2)(i) Except as provided in paragraphs (d)(2)(ii) and (iii) of this section, after the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section, upon any determination that would otherwise result in the initial recordation of a given number of CSAPR NO_X Ozone Season Group 1 allowances in the compliance account for a source in a State listed in § 52.38(b)(2)(ii) of this chapter (and Indian country within the borders of such a State), the Administrator will not record such CSAPR NO_X Ozone Season Group 1 allowances but instead will allocate and record in such account an amount of CSAPR NO_X Ozone Season Group 2 allowances for the control period in 2017 computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 1 allowances divided by the conversion factor determined under paragraph (d)(1)(ii) of this section.

* * * * *

(iii) After the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section and § 97.826(e)(1), upon any determination that would otherwise result in the initial recordation of a given number of CSAPR NO_X Ozone Season Group 1 allowances in the compliance account for a source in a State listed in § 52.38(b)(2)(iii)(B) of this chapter (and Indian country within the borders of such a State), the Administrator will not record such CSAPR NO_X Ozone Season Group 1 allowances but instead will allocate and record in such account an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 1 allowances divided by the conversion factor determined under paragraph (d)(1)(ii) of this section and further divided by the conversion factor determined under § 97.826(e)(1)(ii).

(e) * * *

(3) After the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section and § 97.826(e)(1), the owner or operator of a CSAPR NO_X Ozone Season Group 1 source in a State listed in § 52.38(b)(2)(ii)(C) of this chapter (and Indian country within the borders of such a State) may satisfy a requirement to hold a given number of CSAPR NO_X Ozone Season Group 1 allowances for the control period in 2015 or 2016 by holding instead, in a general account established for this sole purpose, an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 (or any later control period for which the allowance transfer deadline defined in § 97.1002 has passed) computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 1 allowances divided by the conversion factor determined under paragraph (d)(1)(ii) of this section and further divided by the conversion factor determined under § 97.826(e)(1)(ii).

Subpart CCCCC—CSAPR SO_2 Group 1 Trading Program

§ 97.602 [Amended]

■ 44. Amend § 97.602 by:

■ a. In the definition of ''CSAPR NO_X Ozone Season Group 1 Trading Program'', removing ''(b)(2)(i) and (ii), and'' and adding in its place ''(b)(2)(i), and'';

■ b. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and''; and

■ c. In the definition of ''CSAPR NO_X Ozone Season Group 3 Trading Program'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and''.

§ 97.611 [Amended]

■ 45. Amend § 97.611 by:

■ a. In paragraphs (b)(1)(i)(A) and (B), removing ''State, in accordance'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance''; and

■ b. In paragraphs (b)(2)(i)(A) and (B), removing ''Indian country within the borders of a State, in accordance'' and adding in its place ''areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance''.

§ 97.612 [Amended]

■ 46. Amend § 97.612 by:

■ a. In paragraph (a) introductory text, removing ''State, the Administrator'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator'';

■ b. In paragraphs (a)(3)(iii) and (a)(5), adding ''and areas of Indian country within the borders of the State subject to the State's SIP authority'' after ''in the State'';

■ c. In paragraph (a)(10), removing ''State, is allocated'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, is allocated'';

■ d. In paragraph (b) introductory text, removing ''Indian country within the borders of each State, the Administrator'' and adding in its place ''areas of Indian country within the borders of each State not subject to the State's SIP authority, the Administrator''; and

■ e. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority''.

§ 97.626 [Amended]

■ 47. In § 97.626, amend paragraph (c) by:

■ a. Removing ''set forth in'' and adding in its place ''established under''; and

■ b. Removing ''State (or Indian'' and adding in its place ''State (and Indian''.

Subpart DDDDD—CSAPR SO_2 Group 2 Trading Program

■ 48. Amend § 97.702 by:
■ a. In the definition of ''Alternate designated representative'', removing ''or CSAPR NO_X Ozone Season Group 2 Trading Program, then'' and adding in its place ''CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, then'';
■ b. In the definition of ''CSAPR NO_X Ozone Season Group 1 Trading Program'', removing ''(b)(2)(i) and (ii), and'' and adding in its place ''(b)(2)(i), and'';
■ c. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and'';
■ d. Adding in alphabetical order a definition for ''CSAPR NO_X Ozone Season Group 3 Trading Program''; and
■ e. In the definition of ''Designated representative'', removing ''or CSAPR NO_X Ozone Season Group 2 Trading Program, then'' and adding in its place ''CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, then''.

The addition reads as follows:

§ 97.702 Definitions.

* * * * *

CSAPR NO_X Ozone Season Group 3 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart GGGGG of this part and § 52.38(b)(1), (b)(2)(iii), and (b)(10) through (14) and (17) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(10) or (11) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(12) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

* * * * *

§ 97.711 [Amended]

■ 49. Amend § 97.711 by:
■ a. In paragraphs (b)(1)(i)(A) and (B), removing ''State, in accordance'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance''; and
■ b. In paragraphs (b)(2)(i)(A) and (B), removing ''Indian country within the borders of a State, in accordance'' and adding in its place ''areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance''.

§ 97.712 [Amended]

■ 50. Amend § 97.712 by:
■ a. In paragraph (a) introductory text, removing ''State, the Administrator'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator'';
■ b. In paragraphs (a)(3)(iii) and (a)(5), adding ''and areas of Indian country within the borders of the State subject to the State's SIP authority'' after ''in the State'';
■ c. In paragraph (a)(10), removing ''State, is allocated'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, is allocated'';
■ d. In paragraph (b) introductory text, removing ''Indian country within the borders of each State, the Administrator'' and adding in its place ''areas of Indian country within the borders of each State not subject to the State's SIP authority, the Administrator''; and
■ e. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority''.

§ 97.726 [Amended]

■ 51. In § 97.726, amend paragraph (c) by:
■ a. Removing ''set forth in'' and adding in its place ''established under''; and
■ b. Removing ''State (or Indian'' and adding in its place ''State (and Indian''.

§ 97.734 [Amended]

■ 52. In § 97.734, amend paragraph (d)(3) by removing ''or CSAPR NO_X Ozone Season Group 2 Trading Program, quarterly'' and adding in its place ''CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, quarterly''.

Subpart EEEEE—CSAPR NO_X Ozone Season Group 2 Trading Program

■ 53. Amend § 97.802 by:
■ a. In the definition of ''Assurance account'', removing ''base CSAPR'' and adding in its place ''CSAPR'';
■ b. Removing the definitions for ''Base CSAPR NO_X Ozone Season Group 2 source'' and ''Base CSAPR NO_X Ozone Season Group 2 unit'';
■ c. In the definition of ''Common designated representative'', removing ''base CSAPR'' and adding in its place ''CSAPR'';
■ d. In the definition of ''Common designated representative's assurance level'', revising paragraph (1);
■ e. In the definition of ''Common designated representative's share'', removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears;
■ f. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and'';
■ g. In the definition of ''CSAPR NO_X Ozone Season Group 3 allowance'':
■ i. Adding ''or (e)'' after ''§ 97.826(d)''; and
■ ii. Adding ''or less'' after ''one ton'';
■ h. In the definition of ''CSAPR NO_X Ozone Season Group 3 Trading Program'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and''; and
■ i. In the definition of ''State'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and''.

The revision reads as follows:

§ 97.802 Definitions.

* * * * *

Common designated representative's assurance level * * *

(1) The amount (rounded to the nearest allowance) equal to the sum of the total amount of CSAPR NO_X Ozone Season Group 2 allowances allocated for such control period to the group of one or more CSAPR NO_X Ozone Season Group 2 units in such State (and such Indian country) having the common designated representative for such control period and the total amount of CSAPR NO_X Ozone Season Group 2 allowances purchased by an owner or operator of such CSAPR NO_X Ozone Season Group 2 units in an auction for such control period and submitted by the State or the permitting authority to the Administrator for recordation in the compliance accounts for such CSAPR NO_X Ozone Season Group 2 units in accordance with the CSAPR NO_X Ozone Season Group 2 allowance auction provisions in a SIP revision approved by the Administrator under § 52.38(b)(8) or (9) of this chapter, multiplied by the sum of the State NO_X Ozone Season Group 2 trading budget under § 97.810(a) and the State's variability limit under § 97.810(b) for such control period, and divided by such State NO_X Ozone Season Group 2 trading budget;

* * * * *

§ 97.806 [Amended]

■ 54. Amend § 97.806 by:
■ a. In paragraphs (c)(2)(i) introductory text, (c)(2)(i)(B), and (c)(2)(iii) and (iv),

removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears;

■ b. In paragraph (c)(3)(i), removing ''paragraph (c)(1)'' and adding in its place ''paragraphs (c)(1) and (2)''; and

■ c. Removing and reserving paragraph (c)(3)(ii).

§ 97.810 [Amended]

■ 55. In § 97.810, amend paragraphs (a)(1)(i) through (iii), (a)(2)(i) and (ii), (a)(12)(i) through (iii), (a)(13)(i) and (ii), (a)(17)(i) through (iii), (a)(20)(i) through (iii), (a)(23)(i) through (iii), and (b)(1), (2), (12), (13), (17), (20), and (23) by removing ''and thereafter'' and adding in its place ''through 2022''.

■ 56. Amend § 97.811 by:

■ a. In paragraphs (b)(1)(i)(A) and (B), removing ''State, in accordance'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance'';

■ b. In paragraphs (b)(2)(i)(A) and (B), removing ''Indian country within the borders of a State, in accordance'' and adding in its place ''areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance'';

■ c. In paragraph (d)(1), removing ''§ 52.38(b)(2)(iv) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(ii)(B) of this chapter (and''; and

■ d. Adding paragraph (e).

The addition reads as follows:

§ 97.811 Timing requirements for CSAPR NO_X Ozone Season Group 2 allowance allocations.

* * * * *

(e) *Recall of CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods after 2022.* (1) Notwithstanding any other provision of this subpart, part 52 of this chapter, or any SIP revision approved under § 52.38(b) of this chapter, the provisions of this paragraph (e)(1) and paragraphs (e)(2) through (7) of this section shall apply with regard to each CSAPR NO_X Ozone Season Group 2 allowance that was allocated for a control period after 2022 to any unit (including a permanently retired unit qualifying for an exemption under § 97.805) in a State listed in § 52.38(b)(2)(ii)(C) of this chapter (and Indian country within the borders of such a State) and that was initially recorded in the compliance account for the source that includes the unit, whether such CSAPR NO_X Ozone Season Group 2 allowance was allocated pursuant to this subpart or pursuant to a SIP revision approved under § 52.38(b) of this chapter and whether such CSAPR NO_X Ozone Season Group 2 allowance remains in such compliance account or has been transferred to another Allowance Management System account.

(2)(i) For each CSAPR NO_X Ozone Season Group 2 allowance described in paragraph (e)(1) of this section that was allocated for a given control period and initially recorded in a given source's compliance account, one CSAPR NO_X Ozone Season Group 2 allowance that was allocated for the same or an earlier control period and initially recorded in the same or any other Allowance Management System account must be surrendered in accordance with the procedures in paragraphs (e)(3) and (4) of this section.

(ii)(A) The surrender requirement under paragraph (e)(2)(i) of this section corresponding to each CSAPR NO_X Ozone Season Group 2 allowance described in paragraph (e)(1) of this section initially recorded in a given source's compliance account shall apply to such source's current owners and operators, except as provided in paragraph (e)(2)(ii)(B) of this section.

(B) If the owners and operators of a given source as of a given date assumed ownership and operational control of the source through a transaction that did not also provide rights to direct the use or transfer of a given CSAPR NO_X Ozone Season Group 2 allowance described in paragraph (e)(1) of this section with regard to such source (whether recordation of such CSAPR NO_X Ozone Season Group 2 allowance in the source's compliance account occurred before such transaction or was anticipated to occur after such transaction), then the surrender requirement under paragraph (e)(2)(i) of this section corresponding to such CSAPR NO_X Ozone Season Group 2 allowance shall apply to the most recent former owners and operators of the source before the occurrence of such a transaction.

(C) The Administrator will not adjudicate any private legal dispute among the owners and operators of a source or among the former owners and operators of a source, including any disputes relating to the requirements to surrender CSAPR NO_X Ozone Season Group 2 allowances for the source under paragraph (e)(2)(i) of this section.

(3)(i) As soon as practicable on or after August 4, 2023, the Administrator will send a notification to the designated representative for each source described in paragraph (e)(1) of this section identifying the amounts of CSAPR NO_X Ozone Season Group 2 allowances allocated for each control period after 2022 and recorded in the source's compliance account and the corresponding surrender requirements for the source under paragraph (e)(2)(i) of this section.

(ii) As soon as practicable on or after August 21, 2023, the Administrator will deduct from the compliance account for each source described in paragraph (e)(1) of this section CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy the surrender requirements for the source under paragraph (e)(2)(i) of this section until all such surrender requirements for the source are satisfied or until no more CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy such surrender requirements remain in such compliance account.

(iii) As soon as practicable after completion of the deductions under paragraph (e)(3)(ii) of this section, the Administrator will identify for each source described in paragraph (e)(1) of this section the amounts, if any, of CSAPR NO_X Ozone Season Group 2 allowances allocated for each control period after 2022 and recorded in the source's compliance account for which the corresponding surrender requirements under paragraph (e)(2)(i) of this section have not been satisfied and will send a notification concerning such identified amounts to the designated representative for the source.

(iv) With regard to each source for which unsatisfied surrender requirements under paragraph (e)(2)(i) of this section remain after the deductions under paragraph (e)(3)(ii) of this section:

(A) Except as provided in paragraph (e)(3)(iv)(B) of this section, not later than September 15, 2023, the owners and operators of the source shall hold sufficient CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy such unsatisfied surrender requirements under paragraph (e)(2)(i) of this section in the source's compliance account.

(B) With regard to any portion of such unsatisfied surrender requirements that apply to former owners and operators of the source pursuant to paragraph (e)(2)(ii)(B) of this section, not later than September 15, 2023, such former owners and operators shall hold sufficient CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy such portion of the unsatisfied surrender requirements under paragraph (e)(2)(i) of this section either in the source's compliance account or in another Allowance Management System account identified to the Administrator on or before such date in a submission by the authorized account representative for such account.

(C) As soon as practicable on or after September 15, 2023, the Administrator will deduct from the Allowance

Management System account identified in accordance with paragraph (e)(3)(iv)(A) or (B) of this section CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy the surrender requirements for the source under paragraph (e)(2)(i) of this section until all such surrender requirements for the source are satisfied or until no more CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy such surrender requirements remain in such account.

(v) When making deductions under paragraph (e)(3)(ii) or (iv) of this section to address the surrender requirements under paragraph (e)(2)(i) of this section for a given source:

(A) The Administrator will make deductions to address any surrender requirements with regard to first the 2023 control period and then the 2024 control period.

(B) When making deductions to address the surrender requirements with regard to a given control period, the Administrator will first deduct CSAPR NO_X Ozone Season Group 2 allowances allocated for such given control period and will then deduct CSAPR NO_X Ozone Season Group 2 allowances allocated for each successively earlier control period in sequence.

(C) When deducting CSAPR NO_X Ozone Season Group 2 allowances allocated for a given control period from a given Allowance Management System account, the Administrator will first deduct CSAPR NO_X Ozone Season Group 2 allowances initially recorded in the account under § 97.821 (if the account is a compliance account) in the order of recordation and will then deduct CSAPR NO_X Ozone Season Group 2 allowances recorded in the account under § 97.526(d) or § 97.823 in the order of recordation.

(4)(i) To the extent the surrender requirements under paragraph (e)(2)(i) of this section corresponding to any CSAPR NO_X Ozone Season Group 2 allowances allocated for a control period after 2022 and initially recorded in a given source's compliance account have not been fully satisfied through the deductions under paragraph (e)(3) of this section, as soon as practicable on or after November 15, 2023, the Administrator will deduct such initially recorded CSAPR NO_X Ozone Season Group 2 allowances from any Allowance Management System accounts in which such CSAPR NO_X Ozone Season Group 2 allowances are held, making such deductions in any order determined by the Administrator, until all such surrender requirements for such source have been satisfied or until all such CSAPR NO_X Ozone Season Group 2 allowances have been deducted, except as provided in paragraph (e)(4)(ii) of this section.

(ii) If no person with an ownership interest in a given CSAPR NO_X Ozone Season Group 2 allowance as of April 30, 2022, was an owner or operator of the source in whose compliance account such CSAPR NO_X Ozone Season Group 2 allowance was initially recorded, was a direct or indirect parent or subsidiary of an owner or operator of such source, or was directly or indirectly under common ownership with an owner or operator of such source, the Administrator will not deduct such CSAPR NO_X Ozone Season Group 2 allowance under paragraph (e)(4)(i) of this section. For purposes of this paragraph (e)(4)(ii), each owner or operator of a source shall be deemed to be a person with an ownership interest in any CSAPR NO_X Ozone Season Group 2 allowance held in that source's compliance account. The limitation established by this paragraph (e)(4)(ii) on the deductibility of certain CSAPR NO_X Ozone Season Group 2 allowances under paragraph (e)(4)(i) of this section shall not be construed as a waiver of the surrender requirements under paragraph (e)(2)(i) of this section corresponding to such CSAPR NO_X Ozone Season Group 2 allowances.

(iii) Not less than 45 days before the planned date for any deductions under paragraph (e)(4)(i) of this section, the Administrator will send a notification to the authorized account representative for the Allowance Management System account from which such deductions will be made identifying the CSAPR NO_X Ozone Season Group 2 allowances to be deducted and the data upon which the Administrator has relied and specifying a process for submission of any objections to such data. Any objections must be submitted to the Administrator not later than 15 days before the planned date for such deductions as indicated in such notification.

(5) To the extent the surrender requirements under paragraph (e)(2)(i) of this section corresponding to any CSAPR NO_X Ozone Season Group 2 allowances allocated for a control period after 2022 and initially recorded in a given source's compliance account have not been fully satisfied through the deductions under paragraphs (e)(3) and (4) of this section:

(i) The persons identified in accordance with paragraph (e)(2)(ii) of this section with regard to such source and each such CSAPR NO_X Ozone Season Group 2 allowance shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(ii) Each such CSAPR NO_X Ozone Season Group 2 allowance, and each day in such control period, shall constitute a separate violation of this subpart and the Clean Air Act.

(6) The Administrator will record in the appropriate Allowance Management System accounts all deductions of CSAPR NO_X Ozone Season Group 2 allowances under paragraphs (e)(3) and (4) of this section.

(7)(i) Each submission, objection, or other written communication from a designated representative, authorized account representative, or other person to the Administrator under paragraph (e)(2), (3), or (4) of this section shall be sent electronically to the email address *CSAPR@epa.gov*. Each such communication from a designated representative must contain the certification statement set forth in § 97.814(a), and each such communication from the authorized account representative for a general account must contain the certification statement set forth in § 97.820(c)(2)(ii).

(ii) Each notification from the Administrator to a designated representative or authorized account representative under paragraph (e)(3) or (4) of this section will be sent electronically to the email address most recently received by the Administrator for such representative. In any such notification, the Administrator may provide information by means of a reference to a publicly accessible website where the information is available.

§ 97.812 [Amended]

■ 57. Amend § 97.812 by:

■ a. In paragraph (a) introductory text, removing ''State, the Administrator'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator'';

■ b. In paragraphs (a)(3)(iii) and (a)(5), adding ''and areas of Indian country within the borders of the State subject to the State's SIP authority'' after ''in the State'';

■ c. In paragraph (a)(10), removing ''State, is allocated'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, is allocated'';

■ d. In paragraph (b) introductory text, removing ''Indian country within the borders of each State, the Administrator'' and adding in its place ''areas of Indian country within the borders of each State not subject to the

State's SIP authority, the Administrator''; and

■ e. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority''.

§ 97.825 [Amended]

■ 58. In § 97.825, amend paragraphs (a) introductory text, (a)(2), (b)(1)(i), (b)(1)(ii)(A) and (B), (b)(3), (b)(4)(i), (b)(5), (b)(6)(i), (b)(6)(iii) introductory text, and (b)(6)(iii)(A) and (B) by removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears.

■ 59. Amend § 97.826 by:

■ a. In paragraph (b), removing ''(c) or (d)'' and adding in its place ''(c), (d), or (e)'';

■ b. In paragraph (c):

■ i. Removing ''set forth in'' and adding in its place ''established under''; and

■ ii. Removing ''State (or Indian'' and adding in its place ''State (and Indian'';

■ c. In paragraphs (d)(1)(i)(A) and (B), removing ''§ 52.38(b)(2)(iv)'' and adding in its place ''§ 52.38(b)(2)(ii)(B)'';

■ d. Revising paragraph (d)(1)(i)(C);

■ e. In paragraph (d)(1)(ii) introductory text, removing ''§ 52.38(b)(2)(v)'' and adding in its place ''§ 52.38(b)(2)(iii)(A)'';

■ f. In paragraphs (d)(2)(i) and (d)(3), removing ''§ 52.38(b)(2)(v) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(iii)(A) of this chapter (and'';

■ g. Redesignating paragraph (e) as paragraph (f) and adding a new paragraph (e); and

■ h. Revising newly redesignated paragraphs (f)(1) and (2).

The revisions and additions read as follows:

§ 97.826 Banking and conversion.

* * * * *

(d) * * *

(1) * * *

(i) * * *

(C) The full-season CSAPR NO_X Ozone Season Group 3 allowance bank target, computed as the sum for all States listed in § 52.38(b)(2)(iii)(A) of this chapter of the variability limits under § 97.1010(e) for such States for the control period in 2022.

* * * * *

(e) Notwithstanding any other provision of this subpart, part 52 of this chapter, or any SIP revision approved under § 52.38(b)(8) or (9) of this chapter:

(1) By September 18, 2023, the Administrator will temporarily suspend acceptance of CSAPR NO_X Ozone Season Group 2 allowance transfers submitted under § 97.822 and, before resuming acceptance of such transfers, will take the following actions with regard to every general account and every compliance account except a compliance account for a CSAPR NO_X Ozone Season Group 2 source in a State listed in § 52.38(b)(2)(ii)(A) of this chapter (and Indian country within the borders of such a State):

(i) The Administrator will deduct all CSAPR NO_X Ozone Season Group 2 allowances allocated for the control periods in 2017 through 2022 from each such account.

(ii) The Administrator will determine a conversion factor equal to the greater of 1.0000 or the quotient, expressed to four decimal places, of—

(A) The sum of all CSAPR NO_X Ozone Season Group 2 allowances deducted from all such accounts under paragraph (e)(1)(i) of this section; divided by

(B) The product of the sum of the variability limits for the control period in 2024 under § 97.1010(e) for all States listed in § 52.38(b)(2)(iii)(B) and (C) of this chapter multiplied by a fraction whose numerator is the number of days from August 4, 2023 through September 30, 2023, inclusive, and whose denominator is 153.

(iii) The Administrator will allocate and record in each such account an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 computed as the quotient, rounded up to the nearest allowance, of the number of CSAPR NO_X Ozone Season Group 2 allowances deducted from such account under paragraph (e)(1)(i) of this section divided by the conversion factor determined under paragraph (e)(1)(ii) of this section, except as provided in paragraph (e)(1)(iv) or (v) of this section.

(iv) Where, pursuant to paragraph (e)(1)(i) of this section, the Administrator deducts CSAPR NO_X Ozone Season Group 2 allowances from the compliance account for a source in a State not listed in § 52.38(b)(2)(iii) of this chapter (and Indian country within the borders of such a State), the Administrator will not record CSAPR NO_X Ozone Season Group 3 allowances in that compliance account but instead will allocate and record the amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 computed for such source in accordance with paragraph (e)(1)(iii) of this section in a general account identified by the designated representative for such source, provided that if the designated representative fails to identify such a general account in a submission to the Administrator by September 18, 2023, the Administrator may record such CSAPR NO_X Ozone Season Group 3 allowances in a general account identified or established by the Administrator with the designated representative as the authorized account representative and with the owners and operators of such source (as indicated on the certificate of representation for the source) as the persons represented by the authorized account representative.

(v)(A) In computing any amounts of CSAPR NO_X Ozone Season Group 3 allowances to be allocated to and recorded in general accounts under paragraph (e)(1)(iii) of this section, the Administrator may group multiple general accounts whose ownership interests are held by the same or related persons or entities and treat the group of accounts as a single account for purposes of such computation.

(B) Following a computation for a group of general accounts in accordance with paragraph (e)(1)(v)(A) of this section, the Administrator will allocate to and record in each individual account in such group a proportional share of the quantity of CSAPR NO_X Ozone Season Group 3 allowances computed for such group, basing such shares on the respective quantities of CSAPR NO_X Ozone Season Group 2 allowances removed from such individual accounts under paragraph (e)(1)(i) of this section.

(C) In determining the proportional shares under paragraph (e)(1)(v)(B) of this section, the Administrator may employ any reasonable adjustment methodology to truncate or round each such share up or down to a whole number and to cause the total of such whole numbers to equal the amount of CSAPR NO_X Ozone Season Group 3 allowances computed for such group of accounts in accordance with paragraph (e)(1)(v)(A) of this section, even where such adjustments cause the numbers of CSAPR NO_X Ozone Season Group 3 allowances allocated to some individual accounts to equal zero.

(2) After the Administrator has carried out the procedures set forth in paragraph (e)(1) of this section, upon any determination that would otherwise result in the initial recordation of a given number of CSAPR NO_X Ozone Season Group 2 allowances in the compliance account for a source in a State listed in § 52.38(b)(2)(iii)(B) of this chapter (and Indian country within the borders of such a State), the Administrator will not record such CSAPR NO_X Ozone Season Group 2 allowances but instead will allocate and record in such account an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in

2023 computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 2 allowances divided by the conversion factor determined under paragraph (e)(1)(ii) of this section.

(f) * * *

(1) After the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section, the owner or operator of a CSAPR NO_X Ozone Season Group 2 source in a State listed in § 52.38(b)(2)(ii)(B) of this chapter (and Indian country within the borders of such a State) may satisfy a requirement to hold a given number of CSAPR NO_X Ozone Season Group 2 allowances for a control period in 2017 through 2020 by holding instead, in a general account established for this sole purpose, an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2021 (or any later control period for which the allowance transfer deadline defined in § 97.1002 has passed) computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 2 allowances divided by the conversion factor determined under paragraph (d)(1)(i)(D) of this section.

(2) After the Administrator has carried out the procedures set forth in paragraph (e)(1) of this section, the owner or operator of a CSAPR NO_X Ozone Season Group 2 source in a State listed in § 52.38(b)(2)(ii)(C) of this chapter (and Indian country within the borders of such a State) may satisfy a requirement to hold a given number of CSAPR NO_X Ozone Season Group 2 allowances for a control period in 2017 through 2022 by holding instead, in a general account established for this sole purpose, an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 (or any later control period for which the allowance transfer deadline defined in § 97.1002 has passed) computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 2 allowances divided by the conversion factor determined under paragraph (e)(1)(ii) of this section.

Subpart FFFFF—Texas SO_2 Trading Program

■ 60. Amend § 97.902 by:

■ a. In the definition of ''Alternate designated representative'', removing ''Program or CSAPR NO_X Ozone Season Group 2 Trading Program, then'' and adding in its place ''Program, CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, then'';

■ b. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and'';

■ c. Adding in alphabetical order a definition for ''CSAPR NO_X Ozone Season Group 3 Trading Program''; and

■ d. In the definition of ''Designated representative'', removing ''Program or CSAPR NO_X Ozone Season Group 2 Trading Program, then'' and adding in its place ''Program, CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, then''.

The addition reads as follows:

§ 97.902 Definitions.

* * * * *

CSAPR NO_X Ozone Season Group 3 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart GGGGG of this part and § 52.38(b)(1), (b)(2)(iii), and (b)(10) through (14) and (17) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(10) or (11) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(12) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

* * * * *

§ 97.934 [Amended]

■ 61. In § 97.934, amend paragraph (d)(3) by removing ''Program or CSAPR NO_X Ozone Season Group 2 Trading Program, quarterly'' and adding in its place ''Program, CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, quarterly''.

Subpart GGGGG—CSAPR NO_X Ozone Season Group 3 Trading Program

■ 62. Amend § 97.1002 by:

■ a. Revising the definition of ''Allocate or allocation'';

■ b. In the definition of ''Allowance transfer deadline'', adding ''primary'' before ''emissions limitation'';

■ c. In the definition of ''Alternate designated representative'', removing ''or CSAPR SO_2 Group 1 Trading Program, then'' and adding in its place ''CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then'';

■ d. In the definition of ''Assurance account'', removing ''base CSAPR'' and adding in its place ''CSAPR'';

■ e. Adding in alphabetical order a definition for ''Backstop daily NO_X emissions rate'';

■ f. Removing the definitions for ''Base CSAPR NO_X Ozone Season Group 3 source'' and ''Base CSAPR NO_X Ozone Season Group 3 unit'';

■ g. Adding in alphabetical order a definition for ''Coal-derived fuel'';

■ h. In the definition of ''Common designated representative'', removing ''base CSAPR'' and adding in its place ''CSAPR'';

■ i. Revising the definition of ''Common designated representative's assurance level'';

■ j. In the definition of ''Common designated representative's share'', removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears;

■ k. In the definition of ''Compliance account'', adding ''primary'' before ''emissions limitation'';

■ l. Adding in alphabetical order a definition for ''CSAPR NO_X Ozone Season Group 1 Trading Program'';

■ m. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and'';

■ n. In the definition of ''CSAPR NO_X Ozone Season Group 3 allowance'':

■ i. Adding ''or (e)'' after ''§ 97.826(d)''; and

■ ii. Adding ''or less'' after ''one ton'';

■ o. In the definitions of ''CSAPR NO_X Ozone Season Group 3 allowance deduction'' and ''CSAPR NO_X Ozone Season Group 3 emissions limitation'', adding ''primary'' before ''emissions limitation'';

■ p. Adding in alphabetical order a definition for ''CSAPR NO_X Ozone Season Group 3 secondary emissions limitation'';

■ q. In the definition of ''CSAPR NO_X Ozone Season Group 3 Trading Program'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and'';

■ r. Adding in alphabetical order a definition for ''CSAPR SO_2 Group 2 Trading Program'';

■ s. In the definition of ''Designated representative'', removing ''or CSAPR SO_2 Group 1 Trading Program, then'' and adding in its place ''CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then''.

■ t. In the definition of ''Excess emissions'', adding ''primary'' before ''emissions limitation'';

■ u. Adding in alphabetical order a definition for ''Historical control period''; and

■ v. In the definition of ''State'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and''.

The revisions and additions read as follows:

§ 97.1002 Definitions.

* * * * *

Allocate or *allocation* means, with regard to CSAPR NO_X Ozone Season Group 3 allowances, the determination by the Administrator, State, or permitting authority, in accordance with this subpart, §§ 97.526(d) and 97.826(d) and (e), and any SIP revision submitted by the State and approved by the Administrator under § 52.38(b)(10), (11), or (12) of this chapter, of the amount of such CSAPR NO_X Ozone Season Group 3 allowances to be initially credited, at no cost to the recipient, to:

(1) A CSAPR NO_X Ozone Season Group 3 unit;

(2) A new unit set-aside;

(3) An Indian country new unit set-aside;

(4) An Indian country existing unit set-aside; or

(5) An entity not listed in paragraphs (1) through (4) of this definition;

(6) Provided that, if the Administrator, State, or permitting authority initially credits, to a CSAPR NO_X Ozone Season Group 3 unit qualifying for an initial credit, a credit in the amount of zero CSAPR NO_X Ozone Season Group 3 allowances, the CSAPR NO_X Ozone Season Group 3 unit will be treated as being allocated an amount (*i.e.,* zero) of CSAPR NO_X Ozone Season Group 3 allowances.

* * * * *

Backstop daily NO_X emissions rate means a NO_X emissions rate used in the determination of the CSAPR NO_X Ozone Season Group 3 primary emissions limitation for a CSAPR NO_X Ozone Season Group 3 source in accordance with § 97.1024(b).

* * * * *

Coal-derived fuel means any fuel, whether in a solid, liquid, or gaseous state, produced by the mechanical, thermal, or chemical processing of coal.

* * * * *

Common designated representative's assurance level means, with regard to a specific common designated representative and a State (and Indian country within the borders of such State) and control period in a given year for which the State assurance level is exceeded as described in § 97.1006(c)(2)(iii):

(1) The amount (rounded to the nearest allowance) equal to the sum of the total amount of CSAPR NO_X Ozone Season Group 3 allowances allocated for such control period to the group of one or more CSAPR NO_X Ozone Season Group 3 units in such State (and such Indian country) having the common designated representative for such control period and the total amount of CSAPR NO_X Ozone Season Group 3 allowances purchased by an owner or operator of such CSAPR NO_X Ozone Season Group 3 units in an auction for such control period and submitted by the State or the permitting authority to the Administrator for recordation in the compliance accounts for such CSAPR NO_X Ozone Season Group 3 units in accordance with the CSAPR NO_X Ozone Season Group 3 allowance auction provisions in a SIP revision approved by the Administrator under § 52.38(b)(11) or (12) of this chapter, multiplied by the sum of the State NO_X Ozone Season Group 3 trading budget under § 97.1010(a) and the State's variability limit under § 97.1010(e) for such control period, and divided by such State NO_X Ozone Season Group 3 trading budget;

(2) Provided that the allocations of CSAPR NO_X Ozone Season Group 3 allowances for any control period taken into account for purposes of this definition shall exclude any CSAPR NO_X Ozone Season Group 3 allowances allocated for such control period under § 97.526(d) or § 97.826(d) or (e).

* * * * *

CSAPR NO_X Ozone Season Group 1 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart BBBBB of this part and § 52.38(b)(1), (b)(2)(i), and (b)(3) through (5) and (13) through (15) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(5) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

* * * * *

CSAPR NO_X Ozone Season Group 3 secondary emissions limitation means, for a CSAPR NO_X Ozone Season Group 3 unit to which such a limitation applies under § 97.1025(c)(1) for a control period in a given year, the tonnage of NO_X emissions calculated for the unit in accordance with § 97.1025(c)(2) for such control period.

* * * * *

CSAPR SO_2 Group 2 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established in accordance with subpart DDDDD of this part and § 52.39(a), (c), (g) through (k), and (m) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.39(g) or (h) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.39(i) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

* * * * *

Historical control period means, for a unit as of a given calendar year, the period starting May 1 of a previous calendar year and ending September 30 of that previous calendar year, inclusive, without regard to whether the unit was subject to requirements under the CSAPR NO_X Ozone Season Group 3 Trading Program during such period.

* * * * *

■ 63. Amend § 97.1006 by:

■ a. Revising paragraph (b)(2), paragraph (c)(1) heading, paragraph (c)(1)(i), and paragraph (c)(1)(ii) introductory text;

■ b. Adding paragraphs (c)(1)(iii) and (iv);

■ c. In paragraphs (c)(2)(i) introductory text and (c)(2)(i)(B), removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears;

■ d. Revising paragraph (c)(2)(iii);

■ e. In paragraph (c)(2)(iv), removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears;

■ f. Revising paragraph (c)(3); and

■ g. In paragraph (c)(6) introductory text, adding ''or less'' after ''one ton''.

The revisions and additions read as follows:

§ 97.1006 Standard requirements.

* * * * *

(b) * * *

(2) The emissions and heat input data determined in accordance with §§ 97.1030 through 97.1035 shall be used to calculate allocations of CSAPR NO_X Ozone Season Group 3 allowances under §§ 97.1011 and 97.1012 and to determine compliance with the CSAPR NO_X Ozone Season Group 3 primary and secondary emissions limitations and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§ 97.1030 through 97.1035 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) * * *

(1) *CSAPR NO_X Ozone Season Group 3 primary and secondary emissions limitations*—(i) *Primary emissions limitation.* As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Ozone Season Group 3 source and each CSAPR NO_X Ozone

Season Group 3 unit at the source shall hold, in the source's compliance account, CSAPR NO_X Ozone Season Group 3 allowances available for deduction for such control period under § 97.1024(a) in an amount not less than the amount determined under § 97.1024(b), comprising the sum of—

(A) The tons of total NO_X emissions for such control period from all CSAPR NO_X Ozone Season Group 3 units at the source; plus

(B) Two times the excess, if any, over 50 tons of the sum, for all CSAPR NO_X Ozone Season Group 3 units at the source and all calendar days of the control period, of any NO_X emissions from such a unit on any calendar day of the control period exceeding the NO_X emissions that would have occurred on that calendar day if the unit had combusted the same daily heat input and emitted at any backstop daily NO_X emissions rate applicable to the unit for that control period.

(ii) *Exceedances of primary emissions limitation.* If total NO_X emissions during a control period in a given year from the CSAPR NO_X Ozone Season Group 3 units at a CSAPR NO_X Ozone Season Group 3 source are in excess of the CSAPR NO_X Ozone Season Group 3 primary emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

* * * * *

(iii) *Secondary emissions limitation.* The owner or operator of a CSAPR NO_X Ozone Season Group 3 unit subject to an emissions limitation under § 97.1025(c)(1) shall not discharge, or allow to be discharged, emissions of NO_X to the atmosphere during a control period in excess of the tonnage amount calculated in accordance with § 97.1025(c)(2).

(iv) *Exceedances of secondary emissions limitation.* If total NO_X emissions during a control period in a given year from a CSAPR NO_X Ozone Season Group 3 unit are in excess of the amount of a CSAPR NO_X Ozone Season Group 3 secondary emissions limitation applicable to the unit for the control period under paragraph (c)(1)(iii) of this section, then the owners and operators of the unit and the source at which the unit is located shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) * * *

(iii) Total NO_X emissions from all CSAPR NO_X Ozone Season Group 3 units at CSAPR NO_X Ozone Season Group 3 sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season Group 3 trading budget under § 97.1010(a) and the State's variability limit under § 97.1010(e).

* * * * *

(3) *Compliance periods.* (i) A CSAPR NO_X Ozone Season Group 3 unit shall be subject to the requirements under paragraphs (c)(1)(i) and (ii) and (c)(2) of this section for the control period starting on the later of the applicable date in paragraph (c)(3)(i)(A), (B), or (C) of this section or the deadline for meeting the unit's monitor certification requirements under § 97.1030(b) and for each control period thereafter:

(A) May 1, 2021, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(A) of this chapter;

(B) May 1, 2023, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(B) of this chapter; or

(C) August 4, 2023, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(C) of this chapter.

(ii) A CSAPR NO_X Ozone Season Group 3 unit shall be subject to the requirements under paragraphs (c)(1)(iii) and (iv) of this section for the control period starting on the later of May 1, 2024, or the deadline for meeting the unit's monitor certification requirements under § 97.1030(b) and for each control period thereafter.

* * * * *

■ 64. Revise § 97.1010 to read as follows:

§ 97.1010 State NO_X Ozone Season Group 3 trading budgets, set-asides, and variability limits.

(a) *State NO_X Ozone Season Group 3 trading budgets.* (1)(i) The State NO_X Ozone Season Group 3 trading budgets for allocations of CSAPR NO_X Ozone Season Group 3 allowances for the control periods in 2021 through 2025 shall be as indicated in table 1 to this paragraph (a)(1)(i), subject to prorating for the control period in 2023 as provided in paragraph (a)(1)(ii) of this section:

TABLE 1 TO PARAGRAPH (a)(1)(i)—STATE NO_X OZONE SEASON GROUP 3 TRADING BUDGETS BY CONTROL PERIOD, 2021–2025

[Tons]

State	2021	2022	Portion of 2023 control period before August 4, 2023, before prorating	Portion of 2023 control period on and after August 4, 2023, before prorating	2024	2025
Alabama			13,211	6,379	6,489	6,489
Arkansas			9,210	8,927	8,927	8,927
Illinois	11,223	9,102	8,179	7,474	7,325	7,325
Indiana	17,004	12,582	12,553	12,440	11,413	11,413
Kentucky	17,542	14,051	14,051	13,601	12,999	12,472
Louisiana	16,291	14,818	14,818	9,363	9,363	9,107
Maryland	2,397	1,266	1,266	1,206	1,206	1,206
Michigan	14,384	12,290	9,975	10,727	10,275	10,275
Minnesota				5,504	4,058	4,058
Mississippi			6,315	6,210	5,058	5,037
Missouri			15,780	12,598	11,116	11,116
Nevada				2,368	2,589	2,545
New Jersey	1,565	1,253	1,253	773	773	773
New York	4,079	3,416	3,421	3,912	3,912	3,912
Ohio	13,481	9,773	9,773	9,110	7,929	7,929
Oklahoma			11,641	10,271	9,384	9,376

TABLE 1 TO PARAGRAPH (a)(1)(i)—STATE NO_X OZONE SEASON GROUP 3 TRADING BUDGETS BY CONTROL PERIOD, 2021–2025—Continued

[Tons]

State	2021	2022	Portion of 2023 control period before August 4, 2023, before prorating	Portion of 2023 control period on and after August 4, 2023, before prorating	2024	2025
Pennsylvania	12,071	8,373	8,373	8,138	8,138	8,138
Texas			52,301	40,134	40,134	38,542
Utah				15,755	15,917	15,917
Virginia	6,331	3,897	3,980	3,143	2,756	2,756
West Virginia	15,062	12,884	12,884	13,791	11,958	11,958
Wisconsin			7,915	6,295	6,295	5,988

(ii) For the control period in 2023, the State NO_X Ozone Season Group 3 trading budget for each State shall be calculated as the sum, rounded to the nearest allowance, of the following prorated amounts:

(A) The product of the non-prorated trading budget for the portion of the 2023 control period before August 4, 2023, shown for the State in table 1 to paragraph (a)(1)(i) of this section (or zero if table 1 to paragraph (a)(1)(i) shows no amount for such portion of the 2023 control period for the State) multiplied by a fraction whose numerator is the number of days from May 1, 2023, through the day before August 4, 2023, inclusive, and whose denominator is 153; plus

(B) The product of the non-prorated trading budget for the portion of the 2023 control period on and after August 4, 2023, shown for the State in table 1 to paragraph (a)(1)(i) of this section multiplied by a fraction whose numerator is the number of days from August 4, 2023, through September 30, 2023, inclusive, and whose denominator is 153.

(2)(i) The State NO_X Ozone Season Group 3 trading budget for each State and each control period in 2026 through 2029 shall be the preset trading budget indicated for the State and control period in table 2 to this paragraph (a)(2)(i), except as provided in paragraph (a)(2)(ii) of this section.

TABLE 2 TO PARAGRAPH (a)(2)(i)—PRESET TRADING BUDGETS BY CONTROL PERIOD, 2026–2029

[Tons]

State	2026	2027	2028	2029
Alabama	6,339	6,236	6,236	5,105
Arkansas	6,365	4,031	4,031	3,582
Illinois	5,889	5,363	4,555	4,050
Indiana	8,363	8,135	7,280	5,808
Kentucky	9,697	7,908	7,837	7,392
Louisiana	6,370	3,792	3,792	3,639
Maryland	842	842	842	842
Michigan	6,743	5,691	5,691	4,656
Minnesota	4,058	2,905	2,905	2,578
Mississippi	3,484	2,084	1,752	1,752
Missouri	9,248	7,329	7,329	7,329
Nevada	1,142	1,113	1,113	880
New Jersey	773	773	773	773
New York	3,650	3,388	3,388	3,388
Ohio	7,929	7,929	6,911	6,409
Oklahoma	6,631	3,917	3,917	3,917
Pennsylvania	7,512	7,158	7,158	4,828
Texas	31,123	23,009	21,623	20,635
Utah	6,258	2,593	2,593	2,593
Virginia	2,565	2,373	2,373	1,951
West Virginia	10,818	9,678	9,678	9,678
Wisconsin	4,990	3,416	3,416	3,416

(ii) If the preset trading budget indicated for a given State and control period in table 2 to paragraph (a)(2)(i) of this section is less than the dynamic trading budget for the State and control period referenced in the applicable notice promulgated under paragraph (a)(4)(v)(C) of this section, then the State NO_X Ozone Season Group 3 trading budget for the State and control period shall be the dynamic trading budget for the State and control period referenced in the applicable notice promulgated under paragraph (a)(4)(v)(C) of this section.

(3) The State NO_X Ozone Season Group 3 trading budget for each State and each control period in 2030 and thereafter shall be the dynamic trading budget for the State and control period referenced in the applicable notice promulgated under paragraph (a)(4)(v)(C) of this section.

(4) The Administrator will calculate the dynamic trading budget for each State and each control period in 2026

and thereafter in the year before the year of the control period as follows:

(i) The Administrator will include a unit in a State (and Indian country within the borders of the State) in the calculation of the State's dynamic trading budget for a control period if—

(A) To the best of the Administrator's knowledge, the unit qualifies as a CSAPR NO_X Ozone Season Group 3 unit under § 97.1004, without regard to whether the unit has permanently retired, provided that including a unit in the calculation of a dynamic trading budget does not constitute a determination that the unit is a CSAPR NO_X Ozone Season Group 3 unit, and not including a unit in the calculation of a dynamic trading budget does not constitute a determination that the unit is not a CSAPR NO_X Ozone Season Group 3 unit;

(B) The unit's deadline for certification of monitoring systems under § 97.1030(b) is on or before May 1 of the year two years before the year of the control period for which the dynamic trading budget is being calculated; and

(C) The owner or operator reported heat input greater than zero for the unit in accordance with part 75 of this chapter for the historical control period in the year two years before the year of the control period for which the dynamic trading budget is being calculated.

(ii) For each unit identified for inclusion in the calculation of the State's dynamic trading budget for a control period under paragraph (a)(4)(i) of this section, the Administrator will calculate the heat input amount in mmBtu to be used in the budget calculation as follows:

(A) For each such unit, the Administrator will determine the following unit-level amounts:

(*1*) The total heat input amounts reported in accordance with part 75 of this chapter for the unit for the historical control periods in the years two, three, four, five, and six years before the year of the control period for which the dynamic trading budget is being calculated, except any historical control period that commenced before the unit's first deadline under any regulatory program to begin recording and reporting heat input in accordance with part 75 of this chapter; and

(*2*) The average of the three highest unit-level total heat input amounts identified for the unit under paragraph (a)(4)(iv)(A)(*1*) of this section or, if fewer than three non-zero amounts are identified for the unit, the average of all such non-zero total heat input amounts.

(B) For the State, the Administrator will determine the following state-level amounts:

(*1*) The sum for all units in the State meeting the criterion under paragraph (a)(4)(i)(A) of this section, without regard to whether such units also meet the criteria under paragraphs (a)(4)(i)(B) and (C) of this section, of the total heat input amounts reported in accordance with part 75 of this chapter for the historical control periods in the years two, three, and four years before the year of the control period for which the dynamic trading budget is being calculated, provided that for the historical control periods in 2022 and 2023, the total reported heat input amounts for Nevada and Utah as otherwise determined under this paragraph (a)(4)(ii)(B)(*1*) shall be increased by 13,489,332 mmBtu for Nevada and by 1,888,174 mmBtu for Utah;

(*2*) The average of the three state-level total heat input amounts calculated for the State under paragraph (a)(4)(ii)(B)(*1*) of this section; and

(*3*) The sum for all units identified for inclusion in the calculation of the State's dynamic trading budget for the control period under paragraph (a)(4)(i) of this section of the unit-level average heat input amounts calculated under paragraph (a)(4)(ii)(A)(*2*) of this section.

(C) The heat input amount for a unit used in the calculation of the State's dynamic trading budget shall be the product of the unit-level average total heat input amount calculated for the unit under paragraph (a)(4)(ii)(A)(*2*) of this section multiplied by a fraction whose numerator is the state-level average total heat input amount calculated under paragraph (a)(4)(ii)(B)(*2*) of this section and whose denominator is the state-level sum of the unit-level average heat input amounts calculated under paragraph (a)(4)(ii)(B)(*3*) of this section.

(iii) For each unit identified for inclusion in the calculation of the State's dynamic trading budget for a control period under paragraph (a)(4)(i) of this section, the Administrator will identify the NO_X emissions rate in lb/mmBtu to be used in the calculation as follows:

(A) For a unit listed in the document entitled ''Unit-Specific Ozone Season NO_X Emissions Rates for Dynamic Budget Calculations'' posted at *www.regulations.gov* in docket EPA–HQ–OAR–2021–0668, the NO_X emissions rate used in the calculation for the control period shall be the NO_X emissions rate shown for the unit and control period in that document.

(B) For a unit not listed in the document referenced in paragraph (a)(4)(iii)(A) of this section, the NO_X emissions rate used in the calculation for the control period shall be identified according to the type of unit and the type of fuel combusted by the unit during the control period beginning May 1 on or immediately after the unit's deadline for certification of monitoring systems under § 97.1030(b) as follows:

(*1*) 0.011 lb/mmBtu, for a simple cycle combustion turbine or a combined cycle combustion turbine other than an integrated coal gasification combined cycle unit;

(*2*) 0.030 lb/mmBtu, for a boiler combusting only fuel oil or gaseous fuel (other than coal-derived fuel) during such control period; or

(*3*) 0.050 lb/mmBtu, for a boiler combusting any amount of coal or coal-derived fuel during such control period or any other unit not covered by paragraph (a)(4)(iii)(B)(*1*) or (*2*) of this section.

(iv) The Administrator will calculate the State's dynamic trading budget for the control period as the sum (converted to tons at a conversion factor of 2,000 lb/ton and rounded to the nearest ton), for all units identified for inclusion in the calculation under paragraph (a)(4)(i) of this section, of the product for each such unit of the heat input amount in mmBtu calculated for the unit under paragraph (a)(4)(ii) of this section multiplied by the NO_X emissions rate in lb/mmBtu identified for the unit under paragraph (a)(4)(iii) of this section.

(v)(A) By March 1, 2025 and March 1 of each year thereafter, the Administrator will calculate the dynamic trading budget for each State, in accordance with paragraphs (a)(4)(i) through (iv) of this section and §§ 97.1006(b)(2) and 97.1030 through 97.1035, for the control period in the year after the year of the applicable calculation deadline under this paragraph (a)(4)(v)(A) and will promulgate a notice of data availability of the results of the calculations.

(B) For each notice of data availability required in paragraph (a)(4)(v)(A) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice. Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations (including the identification of the units included in the calculations) are in accordance with the provisions referenced in paragraph (a)(4)(v)(A) of this section.

(C) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (a)(4)(v)(A) of this section. By May 1 immediately after the promulgation of each notice of data availability required in paragraph (a)(4)(v)(A) of this section, the Administrator will promulgate a notice of data availability of the results of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (a)(4)(v)(B) of this section.

(b) *Indian country existing unit set-asides for the control periods in 2023 and thereafter.* The Indian country existing unit set-aside for allocations of CSAPR NO_X Ozone Season Group 3 allowances for each State for each control period in 2023 and thereafter shall be calculated as the sum of all allowance allocations to units in areas of Indian country within the borders of the State not subject to the State's SIP authority as provided in the applicable notice of data availability for the control period referenced in § 97.1011(a)(2).

(c) *New unit set-asides.* (1) The new unit set-asides for allocations of CSAPR NO_X Ozone Season Group 3 allowances for the control periods in 2021 and 2022 for each State with CSAPR NO_X Ozone Season Group 3 trading budgets for such control periods shall be as indicated in table 3 to this paragraph (c)(1):

TABLE 3 TO PARAGRAPH (c)(1)—NEW UNIT SET-ASIDES BY CONTROL PERIOD

[2021–2022 (tons)]

State	2021	2022
Illinois	265	265
Indiana	262	254
Kentucky	309	283
Louisiana	430	430
Maryland	135	115
Michigan	500	482
New Jersey	27	27
New York	168	168
Ohio	291	290
Pennsylvania	335	339
Virginia	185	161
West Virginia	266	261

(2) The new unit set-aside for allocations of CSAPR NO_X Ozone Season Group 3 allowances for each State for each control period in 2023 and thereafter shall be calculated as the product (rounded to the nearest allowance) of the State NO_X Ozone Season Group 3 trading budget for the State and control period established in accordance with paragraph (a) of this section multiplied by—

(i) 0.09, for Nevada for the control periods in 2023 through 2025;

(ii) 0.06, for Ohio for the control periods in 2023 through 2025;

(iii) 0.05, for each State other than Nevada and Ohio for the control periods in 2023 through 2025; or

(iv) 0.05, for each State for each control period in 2026 and thereafter.

(d) *Indian country new unit set-asides for the control periods in 2021 and 2022.* The Indian country new unit set-asides for allocations of CSAPR NO_X Ozone Season Group 3 allowances for the control periods in 2021 and 2022 for each State with CSAPR NO_X Ozone Season Group 3 trading budgets for such control periods shall be as indicated in table 4 to this paragraph (d):

TABLE 4 TO PARAGRAPH (d)—INDIAN COUNTRY NEW UNIT SET-ASIDES BY CONTROL PERIOD

[2021–2022 (tons)]

State	2021	2022
Illinois	....	....
Indiana	....	....
Kentucky	....	....
Louisiana	15	15
Maryland	....	....
Michigan	13	12
New Jersey	....	....
New York	3	3
Ohio	....	....
Pennsylvania	....	....
Virginia	....	....
West Virginia	....	....

(e) *Variability limits.* (1) The variability limits for the State NO_X Ozone Season Group 3 trading budgets for the control periods in 2021 and 2022 for each State with such trading budgets for such control periods shall be as indicated in table 5 to this paragraph (e)(1).

TABLE 5 TO PARAGRAPH (e)(1)—VARIABILITY LIMITS BY CONTROL PERIOD

[2021–2022 (tons)]

State	2021	2022
Illinois	2,356	1,911
Indiana	3,571	2,642
Kentucky	3,684	2,951
Louisiana	3,421	3,112
Maryland	504	266
Michigan	3,021	2,581
New Jersey	329	263
New York	856	717
Ohio	2,831	2,052
Pennsylvania	2,535	1,758
Virginia	1,329	818
West Virginia	3,163	2,706

(2) The variability limit for the State NO_X Ozone Season Group 3 trading budget for each State for each control period in 2023 and thereafter shall be calculated as the product (rounded to the nearest ton) of the State NO_X Ozone Season Group 3 trading budget for the State and control period established in accordance with paragraph (a) of this section multiplied by the greater of—

(i) 0.21; or

(ii) Any excess over 1.00 of the quotient (rounded to two decimal places) of—

(A) The sum for all CSAPR NO_X Ozone Season Group 3 units in the State and Indian country within the borders of the State of the total heat input reported for the control period in mmBtu, provided that, for purposes of this paragraph (e)(2)(ii)(A), the 2023 control period for all States shall be deemed to be the period from May 1, 2023 through September 30, 2023, inclusive; divided by

(B) The state-level total heat input amount used in the calculation of the State NO_X Ozone Season Group 3 trading budget for the State and control period in mmBtu, as identified in accordance with paragraph (e)(3) of this section.

(3) For purposes of paragraph (e)(2)(ii)(B) of this section, the state-level total heat input amount used in the calculation of a State NO_X Ozone Season Group 3 trading budget for a given control period shall be identified as follows:

(i) For a control period in 2023 through 2025, and for a control period in 2026 through 2029 if the State NO_X Ozone Season Group 3 trading budget for the State and control period under paragraph (a)(2) of this section is the preset trading budget set forth for the State and control period in table 2 to paragraph (a)(2)(i) of this section, the state-level total heat input amounts shall be as indicated in table 6 to this paragraph (e)(3)(i).

TABLE 6 TO PARAGRAPH (e)(3)(i)—STATE-LEVEL TOTAL HEAT INPUT USED IN CALCULATIONS OF PRESET TRADING BUDGETS BY CONTROL PERIOD

[2023–2029 (mmBtu)]

State	2023	2024	2025	2026	2027	2028	2029
Alabama	313,037,541	333,030,691	333,030,691	330,396,046	328,650,653	328,650,653	307,987,882
Arkansas	192,843,561	192,843,561	192,843,561	190,921,052	190,921,052	190,921,052	190,921,052
Illinois	274,005,935	286,568,112	286,568,112	253,219,463	253,219,463	214,086,655	193,900,867
Indiana	356,047,916	330,175,944	330,175,944	302,245,332	302,245,332	277,218,546	236,611,101
Kentucky	301,161,750	301,161,750	295,857,697	295,857,697	295,857,697	293,016,485	274,595,978
Louisiana	280,592,592	280,592,592	278,766,253	278,461,807	277,262,840	277,262,840	277,262,840
Maryland	70,725,007	70,725,007	70,725,007	70,725,007	70,725,007	70,725,007	70,725,007
Michigan	313,846,533	299,124,688	299,124,688	258,225,107	258,225,107	258,225,107	222,314,181
Minnesota	128,893,685	107,821,236	107,821,236	107,821,236	93,890,928	93,890,928	85,707,385
Mississippi	192,978,295	189,415,018	189,279,160	189,279,160	189,279,160	176,004,820	176,004,820
Missouri	284,308,851	249,153,661	249,153,661	249,153,661	248,413,545	248,413,545	248,413,545
Nevada	103,489,785	116,979,117	114,729,782	105,018,415	100,193,805	100,193,805	96,378,269
New Jersey	112,233,231	112,233,231	112,233,231	112,233,231	112,233,231	112,233,231	112,233,231
New York	242,853,661	242,853,661	242,853,661	242,853,661	242,853,661	242,853,661	242,853,661
Ohio	412,292,609	386,560,212	386,560,212	386,560,212	386,560,212	358,992,155	342,075,946
Oklahoma	212,903,386	211,187,283	211,165,691	211,145,820	196,160,642	196,160,642	196,160,642
Pennsylvania	550,993,363	550,993,363	550,993,363	550,993,363	550,993,363	550,993,363	487,590,728
Texas	1,395,116,925	1,395,116,925	1,389,251,813	1,389,251,813	1,356,192,532	1,320,040,162	1,280,014,875
Utah	164,519,648	166,407,822	166,407,822	127,217,396	127,217,396	127,217,396	127,217,396
Virginia	202,953,791	194,015,719	194,015,719	194,015,719	194,015,719	194,015,719	186,848,587
West Virginia	306,845,495	273,151,957	273,151,957	273,151,957	273,151,957	273,151,957	273,151,957
Wisconsin	220,794,282	220,792,155	213,038,308	185,469,476	151,343,287	151,343,287	151,343,287

(ii) For a control period in 2026 through 2029 if the State NO_X Ozone Season Group 3 trading budget for the State and control period under paragraph (a)(2) of this section is the dynamic trading budget for the State and control period referenced in the applicable notice promulgated under paragraph (a)(4)(v)(C) of this section, and for a control period in 2030 and thereafter, the state-level total heat input amount shall be the amount for the State and control period calculated under paragraph (a)(4)(ii)(B)(*2*) of this section.

(f) *Relationship of trading budgets, set-asides, and variability limits.* Each State NO_X Ozone Season Group 3 trading budget in this section includes any tons in an Indian country existing unit set-aside, a new unit set-aside, or an Indian country new unit set-aside but does not include any tons in a variability limit.

■ 65. Amend § 97.1011 by revising the section heading and paragraphs (a), (b), paragraph (c) heading, and paragraphs (c)(1) and (5) to read as follows:

§ 97.1011 CSAPR NO_X Ozone Season Group 3 allowance allocations to existing units.

(a) *Allocations to existing units in general.* (1) For the control periods in 2021 and each year thereafter, CSAPR NO_X Ozone Season Group 3 allowances will be allocated to units in each State and areas of Indian country within the borders of the State subject to the State's SIP authority as provided in notices of data availability issued by the Administrator. Starting with the control period in 2026, the notices of data availability will be the notices issued under paragraph (b)(11)(iii) of this section.

(2) For the control periods in 2023 and each year thereafter, CSAPR NO_X Ozone Season Group 3 allowances will be allocated to units in areas of Indian country within the borders of each State not subject to the State's SIP authority as provided in notices of data availability issued by the Administrator. Starting with the control period in 2026, the notices of data availability will be the notices issued under paragraph (b)(11)(iii) of this section.

(3) Providing an allocation to a unit in a notice of data availability does not constitute a determination that the unit is a CSAPR NO_X Ozone Season Group 3 unit, and not providing an allocation to a unit in such notice does not constitute a determination that the unit is not a CSAPR NO_X Ozone Season Group 3 unit.

(b) *Calculation of default allocations to existing units for control periods in 2026 and thereafter.* For each control period in 2026 and thereafter, and for the CSAPR NO_X Ozone Season Group 3 units in each State and areas of Indian country within the borders of the State, the Administrator will calculate default allocations of CSAPR NO_X Ozone Season Group 3 allowances to the CSAPR NO_X Ozone Season Group 3 units as follows:

(1) For each State and control period, the total amount of CSAPR NO_X Ozone Season Group 3 allowances for which the Administrator will calculate default allocations shall be the remainder of the State NO_X Ozone Season Group 3 trading budget for the control period under § 97.1010(a) minus the new unit set-aside for the control period under § 97.1010(c).

(2) The Administrator will calculate a default allocation of CSAPR NO_X Ozone Season Group 3 allowances for each CSAPR NO_X Ozone Season Group 3 unit in the State and Indian country within the borders of the State meeting the following criteria:

(i) To the best of the Administrator's knowledge, the unit qualifies as a CSAPR NO_X Ozone Season Group 3 unit under § 97.1004, without regard to whether the unit has permanently retired;

(ii) The unit's deadline for certification of monitoring systems under § 97.1030(b) is on or before May 1 of the year two years before the year of the control period for which the allowances are being allocated; and

(iii) The owner or operator reported heat input greater than zero for the unit in accordance with part 75 of this chapter for the historical control period in the year two years before the year of the control period for which the allowances are being allocated.

(3) For each CSAPR NO_X Ozone Season Group 3 unit for which a default allocation is being calculated for a control period, the Administrator will calculate an average heat input amount to be used in the allocation calculations as follows:

(i) The Administrator will identify the total heat input amounts reported for the unit in accordance with part 75 of this chapter for the historical control periods in the years two, three, four, five, and six years before the year of the control period for which the allowances are being allocated, except any historical control period that commenced before the unit's first deadline under any regulatory program to begin recording and reporting heat input in accordance with part 75 of this chapter.

(ii) The average heat input amount used in the allocation calculations shall be the average of the three highest total heat input amounts identified for the unit under paragraph (b)(3)(i) of this section or, if fewer than three non-zero amounts are identified for the unit, the average of all such non-zero total heat input amounts.

(4) For each CSAPR NO_X Ozone Season Group 3 unit for which a default allocation is being calculated for a control period, the Administrator will calculate a tentative maximum allocation amount to be used in the allocation calculations as follows:

(i) The Administrator will identify the total NO_X emissions amounts reported for the unit in accordance with part 75 of this chapter for the historical control periods in the years two, three, four, five, and six years before the year of the control period for which the allowances are being allocated.

(ii) The tentative maximum allocation amount used in the allocation calculations shall be the highest of the total NO_X emissions amounts identified for the unit under paragraph (b)(4)(i) of this section or, if less, any applicable amount calculated under paragraph (b)(4)(iii) of this section.

(iii)(A) The tentative maximum allocation amount under paragraph (b)(4)(ii) of this section for a unit described in paragraph (b)(4)(iii)(B) or (C) of this section may not exceed a maximum controlled baseline calculated as the product (converted to tons at a conversion factor of 2,000 lb/ton and rounded to the nearest ton) of the highest total heat input amount identified for the unit under paragraph (b)(3)(i) of this section in mmBtu multiplied by a NO_X emissions rate of 0.08 lb/mmBtu.

(B) For the control period in 2026, a maximum controlled baseline under paragraph (b)(4)(iii)(A) of this section shall apply to any unit that combusted any coal or solid coal-derived fuel during the historical control period for which the unit's heat input was most recently reported, that serves a generator with nameplate capacity of 100 MW or more, and that is equipped with selective catalytic reduction controls, except a circulating fluidized bed boiler.

(C) For each control period in 2027 and thereafter, a maximum controlled baseline under paragraph (b)(4)(iii)(A) of this section shall apply to any unit that combusted any coal or solid coal-derived fuel during the historical control period for which the unit's heat input was most recently reported and that serves a generator with nameplate capacity of 100 MW or more, except a circulating fluidized bed boiler.

(5) The Administrator will calculate the initial unrounded default allocations for each CSAPR NO_X Ozone Season Group 3 unit according to the procedure in paragraph (b)(6) of this section and will recalculate the unrounded default allocations according to the procedures in paragraph (b)(7) or (8) of this section, as applicable, iterating the recalculations as necessary until the total of the unrounded default allocations to all eligible units equals the amount of allowances determined for the State under paragraph (b)(1) of this section.

(6) The Administrator will calculate the initial unrounded default allocations to CSAPR NO_X Ozone Season Group 3 units as follows:

(i) The Administrator will calculate the sum, for all units determined under paragraph (b)(2) of this section to be eligible to receive default allocations, of the units' average heat input amounts determined under paragraph (b)(3)(ii) of this section.

(ii) For each unit determined under paragraph (b)(2) of this section to be eligible to receive a default allocation, the Administrator will calculate the unit's unrounded default allocation as the lesser of—

(A) The product of the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section multiplied by a fraction whose numerator is the unit's average heat input amount determined under paragraph (b)(3)(ii) of this section and whose denominator is the sum determined under paragraph (b)(6)(i) of this section; and

(B) The unit's tentative maximum allocation amount determined under paragraph (b)(4)(ii) of this section.

(iii) If the sum of the unrounded default allocations determined under paragraph (b)(6)(ii) of this section is less than the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section, the Administrator will follow the procedures in paragraph (b)(7) or (8) of this section, as applicable.

(iv) If the sum of the unrounded default allocations determined under paragraph (b)(6)(ii) of this section equals the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section, the Administrator will determine the rounded default allocations according to the procedures in paragraphs (b)(9) and (10) of this section.

(7) If the unrounded default allocation determined in the previous round of the calculation procedure for at least one CSAPR NO_X Ozone Season Group 3 unit is less than the unit's tentative maximum allocation amount determined under paragraph (b)(4)(ii) of this section, the Administrator will recalculate the unrounded default allocations as follows:

(i) The Administrator will calculate the additional pool of allowances to be allocated as the remainder of the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section minus the sum of the unrounded default allocations from the previous round of the calculation procedure for all units determined under paragraph (b)(2) of this section to be eligible to receive default allocations.

(ii) The Administrator will calculate the sum, for all units whose unrounded default allocations determined in the previous round of the calculation procedure were less than the respective units' tentative maximum allocation amounts determined under paragraph (b)(4)(ii) of this section, of the units' average heat input amounts determined under paragraph (b)(3)(ii) of this section.

(iii) For each unit whose unrounded default allocation determined in the previous round of the calculation procedure was less than the unit's tentative maximum allocation amount determined under paragraph (b)(4)(ii) of this section, the Administrator will recalculate the unit's unrounded default allocation as the lesser of—

(A) The sum of the unit's unrounded default allocation determined in the previous round of the calculation procedure plus the product of the additional pool of allowances determined under paragraph (b)(7)(i) of this section multiplied by a fraction whose numerator is the unit's average heat input amount determined under paragraph (b)(3)(ii) of this section and whose denominator is the sum determined under paragraph (b)(7)(ii) of this section; and

(B) The unit's tentative maximum allocation amount determined under paragraph (b)(4)(ii) of this section.

(iv) Except as provided in paragraph (b)(7)(iii) of this section, a unit's unrounded default allocation shall equal the amount determined in the previous round of the calculation procedure.

(v) If the sum of the unrounded default allocations determined under paragraphs (b)(7)(iii) and (iv) of this section is less than the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section, the Administrator will iterate the procedures in paragraph (b)(7) of this section or follow the procedures in paragraph (b)(8) of this section, as applicable.

(vi) If the sum of the unrounded default allocations determined under paragraphs (b)(7)(iii) and (iv) of this section equals the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section, the Administrator will determine the rounded default allocations according to the procedures in paragraphs (b)(9) and (10) of this section.

(8) If the unrounded default allocation determined in the previous round of the calculation procedure for every CSAPR NO_X Ozone Season Group 3 unit equals the unit's tentative maximum allocation amount determined under paragraph (b)(4)(ii) of this section, the Administrator will recalculate the unrounded default allocations as follows:

(i) The Administrator will calculate the additional pool of allowances to be allocated as the remainder of the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section minus the sum of the unrounded default allocations from the previous round of the calculation procedure for all units determined under paragraph (b)(2) of this section to be eligible to receive default allocations.

(ii) The Administrator will recalculate the unrounded default allocation for each eligible unit as the sum of—

(A) The unit's unrounded default allocation as determined in the previous round of the calculation procedure; plus

(B) The product of the additional pool of allowances determined under paragraph (b)(8)(i) of this section multiplied by a fraction whose numerator is the unit's average heat input amount determined under paragraph (b)(3)(ii) of this section and whose denominator is the sum determined under paragraph (b)(6)(i) of this section.

(9) The Administrator will round the default allocation for each eligible unit determined under paragraph (b)(6), (7), or (8) of this section to the nearest allowance and make any adjustments required under paragraph (b)(10) of this section.

(10) If the sum of the default allocations after rounding under paragraph (b)(9) of this section does not equal the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section, the Administrator will adjust the default allocations as follows. The Administrator will list the CSAPR NO_X Ozone Season Group 3 units in descending order based on such units' allocation amounts under paragraph (b)(9) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant sources' names and numerical order of the relevant units' identification numbers, and will adjust each unit's allocation amount upward or downward by one CSAPR NO_X Ozone Season Group 3 allowance (but not below zero) in the order in which the units are listed, and will repeat this adjustment process as necessary, until the total of the adjusted default allocations equals the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section.

(11)(i) By March 1, 2025 and March 1 of each year thereafter, the Administrator will calculate the default allocation of CSAPR NO_X Ozone Season Group 3 allowances to each CSAPR NO_X Ozone Season Group 3 unit in a State and Indian country within the borders of the State, in accordance with paragraphs (b)(1) through (10) of this section and §§ 97.1006(b)(2) and 97.1030 through 97.1035, for the control period in the year after the year of the applicable calculation deadline under this paragraph (b)(11)(i) and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(11)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice. Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations (including the identification of the CSAPR NO_X Ozone Season Group 3 units) are in accordance with the provisions referenced in paragraph (b)(11)(i) of this section.

(iii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(11)(i) of this section. By May 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(11)(i) of this section, the Administrator will promulgate a notice of data availability of the results of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(11)(ii) of this section.

(c) *Incorrect allocations of CSAPR NO_X Ozone Season Group 3 allowances to existing units.* (1) For each control period in 2021 and thereafter, if the Administrator determines that CSAPR NO_X Ozone Season Group 3 allowances were allocated for the control period to a recipient covered by the provisions of paragraph (c)(1)(i), (ii), or (iii) of this section, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section:

(i) The recipient is not actually a CSAPR NO_X Ozone Season Group 3 unit under § 97.1004 as of the first day of the control period and is allocated CSAPR NO_X Ozone Season Group 3 allowances for such control period under paragraph (a)(1) or (2) of this section;

(ii) The recipient is not actually a CSAPR NO_X Ozone Season Group 3 unit under § 97.1004 as of the first day of the control period and is allocated CSAPR NO_X Ozone Season Group 3 allowances for such control period under a provision of a SIP revision approved under § 52.38(b)(10), (11), or (12) of this chapter that the SIP revision provides should be allocated only to recipients that are CSAPR NO_X Ozone Season Group 3 units as of the first day of such control period; or

(iii) The recipient is not located as of the first day of the control period in the State (and Indian country within the borders of the State) from whose NO_X Ozone Season Group 3 trading budget CSAPR NO_X Ozone Season Group 3 allowances were allocated to the recipient for such control period under paragraph (a)(1) or (2) of this section or under a provision of a SIP revision approved under § 52.38(b)(10), (11), or (12) of this chapter.

* * * * *

(5) With regard to any CSAPR NO_X Ozone Season Group 3 allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section:

(i) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs on or before May 1, 2024, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to the new unit set-aside for 2021, 2022, or 2023 for the State from whose NO_X Ozone Season Group 3 trading budget the CSAPR NO_X Ozone Season Group 3 allowances were allocated.

(ii) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs after May 1, 2024, and on or before May 1 of the year following the year of the control period for which the CSAPR NO_X Ozone Season Group 3 allowances were allocated, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to the new unit set-aside for such control period for the State from whose NO_X Ozone Season Group 3 trading budget the CSAPR NO_X Ozone Season Group 3 allowances were allocated.

(iii) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs after May 1, 2024, and after May 1 of the year following the year of the control period for which the CSAPR NO_X Ozone Season Group 3 allowances were allocated, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to a surrender account.

■ 66. Amend § 97.1012 by:
■ a. Revising paragraphs (a) introductory text and (a)(1)(i) and (ii);
■ b. Removing paragraphs (a)(1)(iii) and (iv);
■ c. Revising paragraphs (a)(2) and (a)(3)(i);
■ d. In paragraph (a)(3)(ii), adding ''and'' after the semicolon;
■ e. Revising paragraph (a)(3)(iii);
■ f. Removing paragraph (a)(3)(iv);
■ g. Revising paragraph (a)(4)(i);
■ h. Redesignating paragraph (a)(4)(ii) as paragraph (a)(4)(iii) and adding a new paragraph (a)(4)(ii);
■ i. Revising paragraphs (a)(5) and (10):
■ j. In paragraph (a)(11), removing ''§ 97.1011(b)(1)(i), (ii), and (v), of'' and adding in its place ''paragraph (a)(13) of this section, of'';
■ k. Adding paragraph (a)(13);
■ l. Revising paragraphs (b) introductory text and (b)(1) and (2);
■ m. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority'';
■ n. Revising paragraph (b)(10);
■ o. In paragraph (b)(11), removing ''§ 97.1011(b)(2)(i), (ii), and (v), of'' and adding in its place ''paragraph (b)(13) of this section, of''; and
■ p. Adding paragraphs (b)(13) and (c).

The revisions and additions read as follows:

§ 97.1012 CSAPR NO_X Ozone Season Group 3 allowance allocations to new units.

(a) *Allocations from new unit set-asides.* For each control period in 2021 and thereafter for a State listed in § 52.38(b)(2)(iii)(A) of this chapter, or 2023 and thereafter for a State listed in § 52.38(b)(2)(iii)(B) or (C) of this chapter, and for the CSAPR NO_X Ozone Season Group 3 units in each State and areas of Indian country within the borders of the State (except, for the control periods in 2021 and 2022, areas of Indian country within the borders of the State not subject to the State's SIP authority), the Administrator will allocate CSAPR NO_X Ozone Season Group 3 allowances to the CSAPR NO_X Ozone Season Group 3 units as follows:

(1) * * *

(i) CSAPR NO_X Ozone Season Group 3 units that are not allocated an amount of CSAPR NO_X Ozone Season Group 3 allowances for such control period in the applicable notice of data availability referenced in § 97.1011(a)(1) or (2) and that have deadlines for certification of monitoring systems under § 97.1030(b) not later than September 30 of the year of the control period; or

(ii) CSAPR NO_X Ozone Season Group 3 units whose allocation of an amount of CSAPR NO_X Ozone Season Group 3 allowances for such control period in the applicable notice of data availability referenced in § 97.1011(a)(1) or (2) is covered by § 97.1011(c)(2) or (3).

(2) The Administrator will establish a separate new unit set-aside for the State for each such control period. Each such new unit set-aside will be allocated CSAPR NO_X Ozone Season Group 3 allowances in an amount equal to the applicable amount of tons of NO_X emissions as set forth in § 97.1010(c) and will be allocated additional CSAPR NO_X Ozone Season Group 3 allowances (if any) in accordance with § 97.1011(c)(5) and paragraphs (b)(10) and (c)(5) of this section.

(3) * * *

(i) The control period in 2021, for a State listed in § 52.38(b)(2)(iii)(A) of this chapter, or the control period in 2023, for a State listed in § 52.38(b)(2)(iii)(B) or (C) of this chapter;

* * * * *

(iii) For a unit described in paragraph (a)(1)(ii) of this section, the first control period in which the CSAPR NO_X Ozone Season Group 3 unit operates in the State and Indian country within the borders of the State (except, for the control periods in 2021 and 2022, areas of Indian country within the borders of the State not subject to the State's SIP authority) after operating in another jurisdiction and for which the unit is not already allocated one or more CSAPR NO_X Ozone Season Group 3 allowances.

(4)(i) The allocation to each CSAPR NO_X Ozone Season Group 3 unit described in paragraphs (a)(1)(i) through (iii) of this section and for each control period described in paragraph (a)(3) of this section will be an amount equal to the unit's total tons of NO_X emissions during the control period or, if less, any applicable amount calculated under paragraph (a)(4)(ii) of this section.

(ii)(A) The allocation under paragraph (a)(4)(i) of this section to a unit described in paragraph (a)(4)(ii)(B) or (C) of this section may not exceed a maximum controlled baseline calculated as the product (converted to tons at a conversion factor of 2,000 lb/ton and rounded to the nearest ton) of the unit's total heat input during the control period in mmBtu multiplied by a NO_X emissions rate of 0.08 lb/mmBtu.

(B) For a control period in 2024 through 2026, a maximum controlled baseline under paragraph (a)(4)(ii)(A) of this section shall apply to any unit combusting any coal or solid coal-derived fuel during the control period, serving a generator with nameplate capacity of 100 MW or more, and equipped with selective catalytic reduction controls on or before September 30 of the preceding control period, except a circulating fluidized bed boiler.

(C) For a control period in 2027 and thereafter, a maximum controlled baseline under paragraph (a)(4)(ii)(A) of this section shall apply to any unit combusting any coal or solid coal-derived fuel during the control period and serving a generator with nameplate capacity of 100 MW or more, except a circulating fluidized bed boiler.

* * * * *

(5) The Administrator will calculate the sum of the allocation amounts of CSAPR NO_X Ozone Season Group 3 allowances determined for all such CSAPR NO_X Ozone Season Group 3 units under paragraph (a)(4)(i) of this section in the State and Indian country within the borders of the State (except, for the control periods in 2021 and 2022, areas of Indian country within the borders of the State not subject to the State's SIP authority) for such control period.

* * * * *

(10)(i) For a control period in 2021 or 2022, if, after completion of the procedures under paragraphs (a)(2) through (7) and (12) of this section for a control period, any unallocated CSAPR NO_X Ozone Season Group 3 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate to each CSAPR NO_X Ozone Season Group 3 unit that is in the State and areas of Indian country within the borders of the State subject to the State's

SIP authority and is allocated an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in the applicable notice of data availability referenced in § 97.1011(a)(1) an amount of CSAPR NO_X Ozone Season Group 3 allowances equal to the following: The total amount of such remaining unallocated CSAPR NO_X Ozone Season Group 3 allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.1011(a)(1) for such control period, divided by the remainder of the amount of tons in the applicable State NO_X Ozone Season Group 3 trading budget minus the sum of the amounts of tons in such new unit set-aside and the Indian country new unit set-aside for the State for such control period, and rounded to the nearest allowance.

(ii) For a control period in 2023 or thereafter, if, after completion of the procedures under paragraphs (a)(2) through (7) and (12) of this section for a control period, any unallocated CSAPR NO_X Ozone Season Group 3 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate to each CSAPR NO_X Ozone Season Group 3 unit that is in the State and Indian country within the borders of the State and is allocated an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period by the Administrator in the applicable notice of data availability referenced in § 97.1011(a)(1) or (2), or under a provision of a SIP revision approved under § 52.38(b)(10), (11), or (12) of this chapter, an amount of CSAPR NO_X Ozone Season Group 3 allowances equal to the following: The total amount of such remaining unallocated CSAPR NO_X Ozone Season Group 3 allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.1011(a)(1) or (2) or a provision of a SIP revision approved under § 52.38(b)(10), (11), or (12) of this chapter for such control period, divided by the remainder of the amount of tons in the applicable State NO_X Ozone Season Group 3 trading budget minus the amount of tons in such new unit set-aside for the State for such control period, and rounded to the nearest allowance.

* * * * *

(13)(i) By March 1, 2022, and March 1 of each year thereafter, the Administrator will calculate the CSAPR NO_X Ozone Season Group 3 allowance allocation to each CSAPR NO_X Ozone Season Group 3 unit in a State and Indian country within the borders of the State (except, for the control periods in 2021 and 2022, areas of Indian country within the State not subject to the State's SIP authority), in accordance with paragraphs (a)(2) through (7), (10), and (12) of this section and §§ 97.1006(b)(2) and 97.1030 through 97.1035, for the control period in the year before the year of the applicable calculation deadline under this paragraph (a)(13)(i) and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (a)(13)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice. Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations (including the identification of the CSAPR NO_X Ozone Season Group 3 units) are in accordance with the provisions referenced in paragraph (a)(13)(i) of this section.

(iii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (a)(13)(i) of this section. By May 1 immediately after the promulgation of each notice of data availability required in paragraph (a)(13)(i) of this section, the Administrator will promulgate a notice of data availability of the results of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (a)(13)(ii) of this section.

(b) *Allocations from Indian country new unit set-asides.* For the control periods in 2021 and 2022, for a State listed in § 52.38(b)(2)(iii)(A) of this chapter, and for the CSAPR NO_X Ozone Season Group 3 units in areas of Indian country within the borders of each such State not subject to the State's SIP authority, the Administrator will allocate CSAPR NO_X Ozone Season Group 3 allowances to the CSAPR NO_X Ozone Season Group 3 units as follows:

(1) The CSAPR NO_X Ozone Season Group 3 allowances will be allocated to CSAPR NO_X Ozone Season Group 3 units that are not allocated an amount of CSAPR NO_X Ozone Season Group 3 allowances for such control period in the applicable notice of data availability referenced in § 97.1011(a)(1) and that have deadlines for certification of monitoring systems under § 97.1030(b) not later than September 30 of the year of the control period, except as provided in paragraph (b)(10) of this section.

(2) The Administrator will establish a separate Indian country new unit set-aside for the State for each such control period. Each such Indian country new unit set-aside will be allocated CSAPR NO_X Ozone Season Group 3 allowances in an amount equal to the applicable amount of tons of NO_X emissions as set forth in § 97.1010(d) and will be allocated additional CSAPR NO_X Ozone Season Group 3 allowances (if any) in accordance with paragraph (c)(5) of this section.

* * * * *

(10) If, after completion of the procedures under paragraphs (b)(2) through (7) and (12) of this section for a control period, any unallocated CSAPR NO_X Ozone Season Group 3 allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will transfer such unallocated CSAPR NO_X Ozone Season Group 3 allowances to the new unit set-aside for the State for such control period.

* * * * *

(13)(i) By March 1, 2022, and March 1, 2023, the Administrator will calculate the CSAPR NO_X Ozone Season Group 3 allowance allocation to each CSAPR NO_X Ozone Season Group 3 unit in areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance with paragraphs (b)(2) through (7), (10), and (12) of this section and §§ 97.1006(b)(2) and 97.1030 through 97.1035, for the control period in the year before the year of the applicable calculation deadline under this paragraph (b)(13)(i) and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(13)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice. Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations (including the identification of the CSAPR NO_X Ozone Season Group 3 units) are in accordance with the provisions referenced in paragraph (b)(13)(i) of this section.

(iii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(13)(i) of this section. By May 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(13)(i) of this section, the Administrator will promulgate a notice of data availability of the results of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(13)(ii) of this section.

(c) *Incorrect allocations of CSAPR NO_X Ozone Season Group 3 allowances to new units.* (1) For each control period in 2021 and thereafter, if the Administrator determines that CSAPR NO_X Ozone Season Group 3 allowances were allocated for the control period under paragraphs (a)(2) through (7) and (12) of this section or paragraphs (b)(2) through (7) and (12) of this section to a recipient that is not actually a CSAPR NO_X Ozone Season Group 3 unit under § 97.1004 as of the first day of such control period, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section.

(2) Except as provided in paragraph (c)(3) or (4) of this section, the Administrator will not record such CSAPR NO_X Ozone Season Group 3 allowances under § 97.1021.

(3) If the Administrator already recorded such CSAPR NO_X Ozone Season Group 3 allowances under § 97.1021 and if the Administrator makes the determination under paragraph (c)(1) of this section before making deductions for the source that includes such recipient under § 97.1024(b) for such control period, then the Administrator will deduct from the account in which such CSAPR NO_X Ozone Season Group 3 allowances were recorded an amount of CSAPR NO_X Ozone Season Group 3 allowances allocated for the same or a prior control period equal to the amount of such already recorded CSAPR NO_X Ozone Season Group 3 allowances. The authorized account representative shall ensure that there are sufficient CSAPR NO_X Ozone Season Group 3 allowances in such account for completion of the deduction.

(4) If the Administrator already recorded such CSAPR NO_X Ozone Season Group 3 allowances under § 97.1021 and if the Administrator makes the determination under paragraph (c)(1) of this section after making deductions for the source that includes such recipient under § 97.1024(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded CSAPR NO_X Ozone Season Group 3 allowances.

(5) With regard to any CSAPR NO_X Ozone Season Group 3 allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section:

(i) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs on or before May 1, 2023, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to the new unit set-aside, in the case of allowances allocated under paragraph (a) of this section, or the Indian country new unit set-aside, in the case of allowances allocated under paragraph (b) of this section, for the control period in 2021 or 2022 for the State from whose NO_X Ozone Season Group 3 trading budget the CSAPR NO_X Ozone Season Group 3 allowances were allocated.

(ii) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs after May 1, 2023, and on or before May 1, 2024, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to the new unit set-aside for the control period in 2023 for the State from whose NO_X Ozone Season Group 3 trading budget the CSAPR NO_X Ozone Season Group 3 allowances were allocated.

(iii) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs after May 1, 2024, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to a surrender account.

■ 67. Amend § 97.1021 by:
■ a. In paragraph (a), removing ''§ 97.1011(a)'' and adding in its place ''§ 97.1011(a)(1)'';
■ b. Revising paragraph (b);
■ c. Removing and reserving paragraph (c);
■ d. Adding paragraphs (d) and (e);
■ e. In paragraph (f), removing ''§ 97.1011(a), or'' and adding in its place ''§ 97.1011(a)(1), or'';
■ f. Redesignating paragraphs (g) and (h) as paragraphs (i) and (j), respectively, and adding new paragraphs (g) and (h);
■ g. Revising newly redesignated paragraph (i);
■ h. In newly redesignated paragraph (j), removing ''and May 1 of each year thereafter, the'' and adding in its place '', and May 1, 2023, the''; and
■ i. In paragraph (m), adding ''or (e)'' after ''§ 97.811(d)'' each time it appears.

The revisions and addition read as follows:

§ 97.1021 Recordation of CSAPR NO_X Ozone Season Group 3 allowance allocations and auction results.

* * * * *

(b) By July 29, 2021, the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2022.

* * * * *

(d) By September 5, 2023, the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2023.

(e) By September 5, 2023, the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2024, unless the State in which the source is located notifies the Administrator in writing by August 4, 2023, of the State's intent to submit to the Administrator a complete SIP revision by September 1, 2023, meeting the requirements of § 52.38(b)(10)(i) through (iv) of this chapter.

(1) If, by September 1, 2023, the State does not submit to the Administrator such complete SIP revision, the Administrator will record by September 15, 2023, in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2024.

(2) If the State submits to the Administrator by September 1, 2023, and the Administrator approves by March 1, 2024, such complete SIP revision, the Administrator will record by March 1, 2024, in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source as provided in such approved, complete SIP revision for the control period in 2024.

(3) If the State submits to the Administrator by September 1, 2023, and the Administrator does not approve by March 1, 2024, such complete SIP revision, the Administrator will record by March 1, 2024, in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances

allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2024.

* * * * *

(g) By September 5, 2023, the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(2) for the control periods in 2023 and 2024.

(h) By July 1, 2024, and July 1 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(2) for the control period in the year after the year of the applicable recordation deadline under this paragraph (h).

(i) By May 1, 2022, and May 1 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1012(a) for the control period in the year before the year of the applicable recordation deadline under this paragraph (i).

* * * * *

■ 68. Amend § 97.1024 by:
■ a. Revising the section heading;
■ b. In paragraphs (a) introductory text and (b) introductory text, adding ''primary'' before ''emissions limitation'';
■ c. Revising paragraph (b)(1);
■ d. Adding paragraph (b)(3); and
■ e. In paragraph (c)(2)(ii), adding ''or (e)'' after ''§ 97.826(d)''.

The revisions and addition read as follows:

§ 97.1024 Compliance with CSAPR NO_X Ozone Season Group 3 primary emissions limitation; backstop daily NO_X emissions rate.

* * * * *

(b) * * *

(1) Until the amount of CSAPR NO_X Ozone Season Group 3 allowances deducted equals the sum of:

(i) The number of tons of total NO_X emissions from all CSAPR NO_X Ozone Season Group 3 units at the source for such control period; plus

(ii) Two times the excess, if any, over 50 tons of the sum (converted to tons at a conversion factor of 2,000 lb/ton and rounded to the nearest ton), for all calendar days in the control period and all CSAPR NO_X Ozone Season Group 3 units at the source to which the backstop daily NO_X emissions rate applies for the control period under paragraph (b)(3) of this section, of any amount by which a unit's NO_X emissions for a given calendar day in pounds exceed the product in pounds of the unit's total heat input in mmBtu for that calendar day multiplied by 0.14 lb/mmBtu; or

* * * * *

(3) The backstop daily NO_X emissions rate of 0.14 lb/mmBtu applies as follows:

(i) For each control period in 2024 through 2029, the backstop daily NO_X emissions rate shall apply to each CSAPR NO_X Ozone Season Group 3 unit combusting any coal or solid coal-derived fuel during the control period, serving a generator with nameplate capacity of 100 MW or more, and equipped with selective catalytic reduction controls on or before September 30 of the preceding control period, except a circulating fluidized bed boiler.

(ii) For each control in 2030 and thereafter, the backstop daily NO_X emissions rate shall apply to each CSAPR NO_X Ozone Season Group 3 unit combusting any coal or solid coal-derived fuel during the control period and serving a generator with nameplate capacity of 100 MW or more, except a circulating fluidized bed boiler.

* * * * *

■ 69. Amend § 97.1025 by:
■ a. Revising the section heading;
■ b. In paragraphs (a) introductory text, (a)(2), (b)(1)(i), (b)(1)(ii)(A) and (B), (b)(3), (b)(4)(i), (b)(5), (b)(6)(i), (b)(6)(iii) introductory text, and (b)(6)(iii)(A) and (B), removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears; and
■ c. Adding paragraph (c).

The revision and addition read as follows:

§ 97.1025 Compliance with CSAPR NO_X Ozone Season Group 3 assurance provisions; CSAPR NO_X Ozone Season Group 3 secondary emissions limitation.

* * * * *

(c) *CSAPR NO_X Ozone Season Group 3 secondary emissions limitation.* (1) The owner or operator of a CSAPR NO_X Ozone Season Group 3 unit equipped with selective catalytic reduction controls or selective non-catalytic reduction controls shall not discharge, or allow to be discharged, emissions of NO_X to the atmosphere during a control period in excess of the tonnage amount calculated in accordance with paragraph (c)(2) of this section, provided that the emissions limitation established under this paragraph (c)(1) shall apply to a unit for a control period only if:

(i) The unit is included for the control period in a group of CSAPR NO_X Ozone Season Group 3 units at CSAPR NO_X Ozone Season Group 3 sources in a State (and Indian country within the borders of such State) having a common designated representative and the owners and operators of such units and sources are subject to a requirement for such control period to hold one or more CSAPR NO_X Ozone Season Group 3 allowances under § 97.1006(c)(2)(i) and paragraph (b) of this section with respect to such group; and

(ii) The unit was required to report NO_X emissions and heat input data for all or portions of at least 367 operating hours during the control period and all or portions of at least 367 operating hours during at least one historical control period under the CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program.

(2) The amount of the emissions limitation applicable to a CSAPR NO_X Ozone Season Group 3 unit for a control period under paragraph (c)(1) of this section, in tons of NO_X, shall be calculated as the sum of 50 plus the product (converted to tons at a conversion factor of 2,000 lb/ton and rounded to the nearest ton) of multiplying—

(i) The total heat input in mmBtu reported for the unit for the control period in accordance with §§ 97.1030 through 97.1035; and

(ii) A NO_X emission rate of 0.10 lb/mmBtu or, if higher, the product of 1.25 times the lowest seasonal average NO_X emission rate in lb/mmBtu achieved by the unit in any historical control period for which the unit was required to report NO_X emissions and heat input data for all or portions of at least 367 operating hours under the CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, where the unit's seasonal average NO_X emission rate for each such historical control period shall be calculated from such reported data as the quotient (converted to lb/mmBtu at a conversion factor of 2,000 lb/ton, and rounded to the nearest 0.0001 lb/mmBtu) of the unit's total NO_X emissions in tons for the historical control period divided by the unit's total heat input in mmBtu for the historical control period.

■ 70. Amend § 97.1026 by:

■ a. Revising the section heading and paragraph (b);
■ b. In paragraph (c):
■ i. Removing ''set forth in'' and adding in its place ''established under''; and
■ ii. Removing ''State (or Indian'' and adding in its place ''State (and Indian''; and
■ c. Adding paragraph (d).

The revision and addition read as follows:

§ 97.1026 Banking; bank recalibration.

* * * * *

(b) Any CSAPR NO_X Ozone Season Group 3 allowance that is held in a compliance account or a general account will remain in such account unless and until the CSAPR NO_X Ozone Season Group 3 allowance is deducted or transferred under § 97.1011(c), § 97.1012(c), § 97.1023, § 97.1024, § 97.1025, § 97.1027, or § 97.1028 or paragraph (c) or (d) of this section.

* * * * *

(d) Before the allowance transfer deadline for each control period in 2024 and thereafter, the Administrator will deduct amounts of CSAPR NO_X Ozone Season Group 3 allowances issued for the control periods in previous years exceeding the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target for the control period in accordance with paragraphs (d)(1) through (4) of this section.

(1) As soon as practicable on or after August 1, 2024, and August 1 of each year thereafter, the Administrator will temporarily suspend acceptance of CSAPR NO_X Ozone Season Group 3 allowance transfers submitted under § 97.1022 and, before resuming acceptance of such transfers, will take the actions in paragraphs (d)(2) through (4) of this section.

(2) The Administrator will determine each of the following values:

(i) The total amount of CSAPR NO_X Ozone Season Group 3 allowances issued for control periods in years before the year of the deadline under paragraph (d)(1) of this section and held in all compliance and general accounts.

(ii) The CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target for the control period in the year of the deadline under paragraph (d)(1) of this section, calculated as the product, rounded to the nearest allowance, of the sum for all States listed in § 52.38(b)(2)(iii) of this chapter of the State NO_X Ozone Season Group 3 trading budgets under § 97.1010(a) for such States for such control period multiplied by—

(A) 0.210, for a control period in 2024 through 2029; or

(B) 0.105, for a control period in 2030 and thereafter.

(3) If the total amount of CSAPR NO_X Ozone Season Group 3 allowances determined under paragraph (d)(2)(i) of this section exceeds the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target determined under paragraph (d)(2)(ii) of this section, then for each compliance account or general account holding CSAPR NO_X Ozone Season Group 3 allowances issued for control periods in years before the year of the deadline under paragraph (d)(1) of this section, the Administrator will:

(i) Determine the total amount of CSAPR NO_X Ozone Season Group 3 allowances issued for control periods in years before the year of the deadline under paragraph (d)(1) of this section and held in the account.

(ii) Determine the account's share of the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target for the control period, calculated as the product, rounded up to the nearest allowance, of the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target determined under paragraph (d)(2)(ii) of this section multiplied by a fraction whose numerator is the total amount of CSAPR NO_X Ozone Season Group 3 allowances held in the account determined under paragraph (d)(3)(i) of this section and whose denominator is the total amount of CSAPR NO_X Ozone Season Group 3 allowances held in all compliance and general accounts determined under paragraph (d)(2)(i) of this section.

(iii) Deduct an amount of CSAPR NO_X Ozone Season Group 3 allowances issued for control periods in years before the year of the deadline under paragraph (d)(1) of this section equal to any positive remainder of the total amount of CSAPR NO_X Ozone Season Group 3 allowances held in the account determined under paragraph (d)(3)(i) of this section minus the account's share of the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target for the control period determined under paragraph (d)(3)(ii) of this section. The allowances will be deducted on a first-in, first-out basis in the order set forth in § 97.1024(c)(2)(i) and (ii).

(iv) Record the deductions under paragraph (d)(3)(iii) of this section in the account.

(4)(i) In computing any amounts of CSAPR NO_X Ozone Season Group 3 allowances to be deducted from general accounts under paragraph (d)(3) of this section, the Administrator may group multiple general accounts whose ownership interests are held by the same or related persons or entities and treat the group of accounts as a single account for purposes of such computation.

(ii) Following a computation for a group of general accounts in accordance with paragraph (d)(4)(i) of this section, the Administrator will deduct from and record in each individual account in such group a proportional share of the quantity of CSAPR NO_X Ozone Season Group 3 allowances computed for such group, basing such shares on the respective quantities of CSAPR NO_X Ozone Season Group 3 allowances determined for such individual accounts under paragraph (d)(3)(i) of this section.

(iii) In determining the proportional shares under paragraph (d)(4)(ii) of this section, the Administrator may employ any reasonable adjustment methodology to truncate or round each such share up or down to a whole number and to cause the total of such whole numbers to equal the amount of CSAPR NO_X Ozone Season Group 3 allowances computed for such group of accounts in accordance with paragraph (d)(4)(i) of this section, even where such adjustments cause the numbers of CSAPR NO_X Ozone Season Group 3 allowances remaining in some individual accounts following the deductions to equal zero.

■ 71. Amend § 97.1030 by:
■ a. Revising paragraph (b)(1); and
■ b. In paragraph (b)(3), removing ''(b)(2)'' and adding in its place ''(b)(1) or (2)'' each time it appears.

The revision reads as follows:

§ 97.1030 General monitoring, recordkeeping, and reporting requirements.

* * * * *

(b) * * *

(1)(i) May 1, 2021, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(A) of this chapter;

(ii) May 1, 2023, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(B) of this chapter;

(iii) August 4, 2023, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(C) of this chapter, where the unit is required to report NO_X mass emissions data or NO_X emissions rate data according to 40 CFR part 75 to address other regulatory requirements; or

(iv) January 31, 2024, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(C) of this chapter, where the unit is not required to report NO_X mass emissions data or NO_X emissions rate data according to 40 CFR part 75 to address other regulatory requirements.

* * * * *

■ 72. Amend § 97.1034 by:

■ a. Revising paragraph (d)(2)(i); and

■ b. In paragraph (d)(4), removing ''or CSAPR SO_2 Group 1 Trading Program, quarterly'' and adding in its place ''CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, quarterly''.

The revision reads as follows:

§ 97.1034 Recordkeeping and reporting.

* * * * *

(d) * * *

(2) * * *

(i)(A) The calendar quarter covering May 1, 2021, through June 30, 2021, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(A) of this chapter;

(B) The calendar quarter covering May 1, 2023, through June 30, 2023, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(B) of this chapter; or

(C) The calendar quarter covering August 4, 2023, through June 30, 2023, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(C) of this chapter;

* * * * *

[FR Doc. 2023–05744 Filed 6–2–23; 8:45 am]

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United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 23-1157 **September Term, 2023**

EPA-88FR36654

Filed On: October 11, 2023

State of Utah, by and through its Governor, Spencer J. Cox, and its Attorney General, Sean D. Reyes,

Petitioner

v.

Environmental Protection Agency and Michael S. Regan, Administrator, U.S. EPA,

Respondents

City of New York, et al.,
Intervenors

Consolidated with 23-1181, 23-1183, 23-1190, 23-1191, 23-1193, 23-1195, 23-1199, 23-1200, 23-1201, 23-1202, 23-1203, 23-1205, 23-1206, 23-1207, 23-1208, 23-1209, 23-1211

BEFORE: Millett, Pillard, and Pan, Circuit Judges

O R D E R

Upon consideration of the motion for a stay in No. 23-1207, the oppositions thereto, and the reply; the motion to sever and hold in abeyance in No. 23-1208, the opposition thereto, and the reply; and the petitions for review in No. 23-1275, et al., it is

ORDERED that the motion for a stay be denied. Petitioner has not satisfied the stringent requirements for a stay pending court review. See Nken v. Holder, 556 U.S. 418, 434 (2009); D.C. Circuit Handbook of Practice and Internal Procedures 33 (2021). It is

United States Court of Appeals

FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 23-1157 **September Term, 2023**

FURTHER ORDERED that the motion to sever and hold in abeyance be denied. It is

FURTHER ORDERED, on the court's own motion, that the parties in No. 23-1157, et al., and No. 23-1275, et al., within 30 days of the date of this order, submit proposed formats for the briefing of these cases and address whether these two sets of consolidated cases should be consolidated with each other or otherwise coordinated. The parties are strongly urged to submit a joint proposal and are reminded that the court looks with extreme disfavor on repetitious submissions and will, where appropriate, require a joint brief of aligned parties with total words not to exceed the standard allotment for a single brief. Whether the parties are aligned or have disparate interests, they must provide *detailed* justifications for any request to file separate briefs or to exceed in the aggregate the standard word allotment. Requests to exceed the standard word allotment must specify the word allotment necessary for each issue.

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

BY: /s/
Emily Campbell
Deputy Clerk

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 23-1157 **September Term, 2023**

EPA-88FR36654

Filed On: September 25, 2023

State of Utah, by and through its Governor, Spencer J. Cox, and its Attorney General, Sean D. Reyes,

Petitioner

v.

Environmental Protection Agency and Michael S. Regan, Administrator, U.S. EPA,

Respondents

City of New York, et al.,
Intervenors

Consolidated with 23-1181, 23-1183, 23-1190, 23-1191, 23-1193, 23-1195, 23-1199, 23-1200, 23-1201, 23-1202, 23-1203, 23-1205, 23-1206, 23-1207, 23-1208, 23-1209, 23-1211

BEFORE: Pillard, Walker*, and Childs, Circuit Judges

O R D E R

Upon consideration of the motions for stay in Nos. 23-1181, 23-1183, 23-1190, 23-1191, 23-1193, 23-1195, 23-1199, 23-1202, and 23-1205, the oppositions thereto, the replies, and the amicus briefs, it is

ORDERED that the motions for stay be denied. Petitioners have not satisfied the stringent requirements for a stay pending court review. See Nken v. Holder, 556

* Judge Walker would stay the federal implementation plan in question.

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 23-1157 **September Term, 2023**

U.S. 418, 434 (2009); D.C. Circuit Handbook of Practice and Internal Procedures 33 (2021).

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

BY: /s/
Tatiana Magruder
Deputy Clerk

until modified or rescinded in accordance with act July 14, 1955, as amended by Pub. L. 95–95 [this chapter], see section 406(b) of Pub. L. 95–95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

§ 7406. Interstate air quality agencies; program cost limitations

For the purpose of developing implementation plans for any interstate air quality control region designated pursuant to section 7407 of this title or of implementing section 7506a of this title (relating to control of interstate air pollution) or section 7511c of this title (relating to control of interstate ozone pollution), the Administrator is authorized to pay, for two years, up to 100 per centum of the air quality planning program costs of any commission established under section 7506a of this title (relating to control of interstate air pollution) or section 7511c of this title (relating to control of interstate ozone pollution) or any agency designated by the Governors of the affected States, which agency shall be capable of recommending to the Governors plans for implementation of national primary and secondary ambient air quality standards and shall include representation from the States and appropriate political subdivisions within the air quality control region. After the initial two-year period the Administrator is authorized to make grants to such agency or such commission in an amount up to three-fifths of the air quality implementation program costs of such agency or commission.

(July 14, 1955, ch. 360, title I, §106, as added Pub. L. 90–148, §2, Nov. 21, 1967, 81 Stat. 490; amended Pub. L. 91–604, §3(c), Dec. 31, 1970, 84 Stat. 1677; Pub. L. 101–549, title I, §102(f)(2), title VIII, §802(f), Nov. 15, 1990, 104 Stat. 2420, 2688.)

Editorial Notes

Codification

Section was formerly classified to section 1857c–1 of this title.

Prior Provisions

A prior section 106 of act July 14, 1955, was renumbered section 117 by Pub. L. 91–604 and is classified to section 7417 of this title.

Amendments

1990—Pub. L. 101–549, §102(f)(2)(A), inserted ''or of implementing section 7506a of this title (relating to control of interstate air pollution) or section 7511c of this title (relating to control of interstate ozone pollution)'' after ''section 7407 of this title''.

Pub. L. 101–549, §102(f)(2)(B), which directed insertion of ''any commission established under section 7506a of this title (relating to control of interstate air pollution) or section 7511c of this title (relating to control of interstate ozone pollution) or'' after ''program costs of'', was executed by making the insertion after that phrase the first place it appeared to reflect the probable intent of Congress.

Pub. L. 101–549, §102(f)(2)(C), which directed insertion of ''or such commission'' after ''such agency'' in last sentence, was executed by making insertion after ''such agency'' the first place it appeared in the last sentence to reflect the probable intent of Congress.

Pub. L. 101–549, §§102(f)(2)(D), 802(f), substituted ''three-fifths of the air quality implementation program costs of such agency or commission'' for ''three-fourths of the air quality planning program costs of such agency''.

1970—Pub. L. 91–604 struck out designation ''(a)'', substituted provisions authorizing Federal grants for the purpose of developing implementation plans and provisions requiring the designated State agency to be capable of recommending plans for implementation of national primary and secondary ambient air quality standards, for provisions authorizing Federal grants for the purpose of expediting the establishment of air quality standards and provisions requiring the designated State agency to be capable of recommending standards of air quality and plans for implementation thereof, respectively, and struck out subsec. (b) which authorized establishment of air quality planning commissions.

§ 7407. Air quality control regions

(a) Responsibility of each State for air quality; submission of implementation plan

Each State shall have the primary responsibility for assuring air quality within the entire geographic area comprising such State by submitting an implementation plan for such State which will specify the manner in which national primary and secondary ambient air quality standards will be achieved and maintained within each air quality control region in such State.

(b) Designated regions

For purposes of developing and carrying out implementation plans under section 7410 of this title—

(1) an air quality control region designated under this section before December 31, 1970, or a region designated after such date under subsection (c), shall be an air quality control region; and

(2) the portion of such State which is not part of any such designated region shall be an air quality control region, but such portion may be subdivided by the State into two or more air quality control regions with the approval of the Administrator.

(c) Authority of Administrator to designate regions; notification of Governors of affected States

The Administrator shall, within 90 days after December 31, 1970, after consultation with appropriate State and local authorities, designate as an air quality control region any interstate area or major intrastate area which he deems necessary or appropriate for the attainment and maintenance of ambient air quality standards. The Administrator shall immediately notify the Governors of the affected States of any designation made under this subsection.

(d) Designations

(1) Designations generally

(A) Submission by Governors of initial designations following promulgation of new or revised standards

By such date as the Administrator may reasonably require, but not later than 1 year after promulgation of a new or revised national ambient air quality standard for any pollutant under section 7409 of this title, the Governor of each State shall (and at any other time the Governor of a State deems appropriate the Governor may) submit to the Administrator a list of all areas (or portions thereof) in the State, designating as—

(i) nonattainment, any area that does not meet (or that contributes to ambient air quality in a nearby area that does not meet) the national primary or secondary ambient air quality standard for the pollutant,

(ii) attainment, any area (other than an area identified in clause (i)) that meets the national primary or secondary ambient air quality standard for the pollutant, or

(iii) unclassifiable, any area that cannot be classified on the basis of available information as meeting or not meeting the national primary or secondary ambient air quality standard for the pollutant.

The Administrator may not require the Governor to submit the required list sooner than 120 days after promulgating a new or revised national ambient air quality standard.

(B) Promulgation by EPA of designations

(i) Upon promulgation or revision of a national ambient air quality standard, the Administrator shall promulgate the designations of all areas (or portions thereof) submitted under subparagraph (A) as expeditiously as practicable, but in no case later than 2 years from the date of promulgation of the new or revised national ambient air quality standard. Such period may be extended for up to one year in the event the Administrator has insufficient information to promulgate the designations.

(ii) In making the promulgations required under clause (i), the Administrator may make such modifications as the Administrator deems necessary to the designations of the areas (or portions thereof) submitted under subparagraph (A) (including to the boundaries of such areas or portions thereof). Whenever the Administrator intends to make a modification, the Administrator shall notify the State and provide such State with an opportunity to demonstrate why any proposed modification is inappropriate. The Administrator shall give such notification no later than 120 days before the date the Administrator promulgates the designation, including any modification thereto. If the Governor fails to submit the list in whole or in part, as required under subparagraph (A), the Administrator shall promulgate the designation that the Administrator deems appropriate for any area (or portion thereof) not designated by the State.

(iii) If the Governor of any State, on the Governor's own motion, under subparagraph (A), submits a list of areas (or portions thereof) in the State designated as nonattainment, attainment, or unclassifiable, the Administrator shall act on such designations in accordance with the procedures under paragraph (3) (relating to redesignation).

(iv) A designation for an area (or portion thereof) made pursuant to this subsection shall remain in effect until the area (or portion thereof) is redesignated pursuant to paragraph (3) or (4).

(C) Designations by operation of law

(i) Any area designated with respect to any air pollutant under the provisions of paragraph (1)(A), (B), or (C) of this subsection (as in effect immediately before November 15, 1990) is designated, by operation of law, as a nonattainment area for such pollutant within the meaning of subparagraph (A)(i).

(ii) Any area designated with respect to any air pollutant under the provisions of paragraph (1)(E) (as in effect immediately before November 15, 1990) is designated by operation of law, as an attainment area for such pollutant within the meaning of subparagraph (A)(ii).

(iii) Any area designated with respect to any air pollutant under the provisions of paragraph (1)(D) (as in effect immediately before November 15, 1990) is designated, by operation of law, as an unclassifiable area for such pollutant within the meaning of subparagraph (A)(iii).

(2) Publication of designations and redesignations

(A) The Administrator shall publish a notice in the Federal Register promulgating any designation under paragraph (1) or (5), or announcing any designation under paragraph (4), or promulgating any redesignation under paragraph (3).

(B) Promulgation or announcement of a designation under paragraph (1), (4) or (5) shall not be subject to the provisions of sections 553 through 557 of title 5 (relating to notice and comment), except nothing herein shall be construed as precluding such public notice and comment whenever possible.

(3) Redesignation

(A) Subject to the requirements of subparagraph (E), and on the basis of air quality data, planning and control considerations, or any other air quality-related considerations the Administrator deems appropriate, the Administrator may at any time notify the Governor of any State that available information indicates that the designation of any area or portion of an area within the State or interstate area should be revised. In issuing such notification, which shall be public, to the Governor, the Administrator shall provide such information as the Administrator may have available explaining the basis for the notice.

(B) No later than 120 days after receiving a notification under subparagraph (A), the Governor shall submit to the Administrator such redesignation, if any, of the appropriate area (or areas) or portion thereof within the State or interstate area, as the Governor considers appropriate.

(C) No later than 120 days after the date described in subparagraph (B) (or paragraph (1)(B)(iii)), the Administrator shall promulgate the redesignation, if any, of the area or portion thereof, submitted by the Governor in accordance with subparagraph (B), making such modifications as the Administrator may deem necessary, in the same manner and under the same procedure as is applicable under clause (ii) of paragraph (1)(B), except that the phrase ''60 days'' shall be substituted for the phrase ''120 days'' in that clause. If the Governor does not submit, in accordance with subparagraph (B), a redesignation for an area (or portion thereof) identified by the Administrator under subparagraph (A), the Administrator shall promulgate such redesignation, if any, that the Administrator deems appropriate.

(D) The Governor of any State may, on the Governor's own motion, submit to the Administrator a revised designation of any area or portion thereof within the State. Within 18 months of receipt of a complete State redesignation submittal, the Administrator shall approve or deny such redesignation. The submission of a redesignation by a Governor shall not affect the effectiveness or enforceability of the applicable implementation plan for the State.

(E) The Administrator may not promulgate a redesignation of a nonattainment area (or portion thereof) to attainment unless—

(i) the Administrator determines that the area has attained the national ambient air quality standard;

(ii) the Administrator has fully approved the applicable implementation plan for the area under section 7410(k) of this title;

(iii) the Administrator determines that the improvement in air quality is due to permanent and enforceable reductions in emissions resulting from implementation of the applicable implementation plan and applicable Federal air pollutant control regulations and other permanent and enforceable reductions;

(iv) the Administrator has fully approved a maintenance plan for the area as meeting the requirements of section 7505a of this title; and

(v) the State containing such area has met all requirements applicable to the area under section 7410 of this title and part D.

(F) The Administrator shall not promulgate any redesignation of any area (or portion thereof) from nonattainment to unclassifiable.

(4) Nonattainment designations for ozone, carbon monoxide and particulate matter (PM–10)

(A) Ozone and carbon monoxide

(i) Within 120 days after November 15, 1990, each Governor of each State shall submit to the Administrator a list that designates, affirms or reaffirms the designation of, or redesignates (as the case may be), all areas (or portions thereof) of the Governor's State as attainment, nonattainment, or unclassifiable with respect to the national ambient air quality standards for ozone and carbon monoxide.

(ii) No later than 120 days after the date the Governor is required to submit the list of areas (or portions thereof) required under clause (i) of this subparagraph, the Administrator shall promulgate such designations, making such modifications as the Administrator may deem necessary, in the same manner, and under the same procedure, as is applicable under clause (ii) of paragraph (1)(B), except that the phrase ''60 days'' shall be substituted for the phrase ''120 days'' in that clause. If the Governor does not submit, in accordance with clause (i) of this subparagraph, a designation for an area (or portion thereof), the Administrator shall promulgate the designation that the Administrator deems appropriate.

(iii) No nonattainment area may be redesignated as an attainment area under this subparagraph.

(iv) Notwithstanding paragraph (1)(C)(ii) of this subsection, if an ozone or carbon monoxide nonattainment area located within a metropolitan statistical area or consolidated metropolitan statistical area (as established by the Bureau of the Census) is classified under part D of this subchapter as a Serious, Severe, or Extreme Area, the boundaries of such area are hereby revised (on the date 45 days after such classification) by operation of law to include the entire metropolitan statistical area or consolidated metropolitan statistical area, as the case may be, unless within such 45-day period the Governor (in consultation with State and local air pollution control agencies) notifies the Administrator that additional time is necessary to evaluate the application of clause (v). Whenever a Governor has submitted such a notice to the Administrator, such boundary revision shall occur on the later of the date 8 months after such classification or 14 months after November 15, 1990, unless the Governor makes the finding referred to in clause (v), and the Administrator concurs in such finding, within such period. Except as otherwise provided in this paragraph, a boundary revision under this clause or clause (v) shall apply for purposes of any State implementation plan revision required to be submitted after November 15, 1990.

(v) Whenever the Governor of a State has submitted a notice under clause (iv), the Governor, in consultation with State and local air pollution control agencies, shall undertake a study to evaluate whether the entire metropolitan statistical area or consolidated metropolitan statistical area should be included within the nonattainment area. Whenever a Governor finds and demonstrates to the satisfaction of the Administrator, and the Administrator concurs in such finding, that with respect to a portion of a metropolitan statistical area or consolidated metropolitan statistical area, sources in the portion do not contribute significantly to violation of the national ambient air quality standard, the Administrator shall approve the Governor's request to exclude such portion from the nonattainment area. In making such finding, the Governor and the Administrator shall consider factors such as population density, traffic congestion, commercial development, industrial development, meteorological conditions, and pollution transport.

(B) PM–10 designations

By operation of law, until redesignation by the Administrator pursuant to paragraph (3)—

(i) each area identified in 52 Federal Register 29383 (Aug. 7, 1987) as a Group I area (except to the extent that such identification was modified by the Administrator before November 15, 1990) is designated nonattainment for PM–10;

(ii) any area containing a site for which air quality monitoring data show a violation of the national ambient air quality standard for PM–10 before January 1, 1989 (as determined under part 50, appendix K of title 40 of the Code of Federal Regulations) is hereby designated nonattainment for PM–10; and

(iii) each area not described in clause (i) or (ii) is hereby designated unclassifiable for PM–10.

Any designation for particulate matter (measured in terms of total suspended particulates) that the Administrator promulgated pursuant to this subsection (as in effect immediately before November 15, 1990) shall remain in effect for purposes of implementing the maximum allowable increases in concentrations of particulate matter (measured in terms of total suspended particulates) pursuant to section 7473(b) of this title, until the Administrator determines that such designation is no longer necessary for that purpose.

(5) Designations for lead

The Administrator may, in the Administrator's discretion at any time the Administrator deems appropriate, require a State to designate areas (or portions thereof) with respect to the national ambient air quality standard for lead in effect as of November 15, 1990, in accordance with the procedures under subparagraphs (A) and (B) of paragraph (1), except that in applying subparagraph (B)(i) of paragraph (1) the phrase "2 years from the date of promulgation of the new or revised national ambient air quality standard" shall be replaced by the phrase "1 year from the date the Administrator notifies the State of the requirement to designate areas with respect to the standard for lead".

(6) Designations

(A) Submission

Notwithstanding any other provision of law, not later than February 15, 2004, the Governor of each State shall submit designations referred to in paragraph (1) for the July 1997 $PM_{2.5}$ national ambient air quality standards for each area within the State, based on air quality monitoring data collected in accordance with any applicable Federal reference methods for the relevant areas.

(B) Promulgation

Notwithstanding any other provision of law, not later than December 31, 2004, the Administrator shall, consistent with paragraph (1), promulgate the designations referred to in subparagraph (A) for each area of each State for the July 1997 $PM_{2.5}$ national ambient air quality standards.

(7) Implementation plan for regional haze

(A) In general

Notwithstanding any other provision of law, not later than 3 years after the date on which the Administrator promulgates the designations referred to in paragraph (6)(B) for a State, the State shall submit, for the entire State, the State implementation plan revisions to meet the requirements promulgated by the Administrator under section 7492(e)(1) of this title (referred to in this paragraph as "regional haze requirements").

(B) No preclusion of other provisions

Nothing in this paragraph precludes the implementation of the agreements and recommendations stemming from the Grand Canyon Visibility Transport Commission Report dated June 1996, including the submission of State implementation plan revisions by the States of Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, or Wyoming by December 31, 2003, for implementation of regional haze requirements applicable to those States.

(e) Redesignation of air quality control regions

(1) Except as otherwise provided in paragraph (2), the Governor of each State is authorized, with the approval of the Administrator, to redesignate from time to time the air quality control regions within such State for purposes of efficient and effective air quality management. Upon such redesignation, the list under subsection (d) shall be modified accordingly.

(2) In the case of an air quality control region in a State, or part of such region, which the Administrator finds may significantly affect air pollution concentrations in another State, the Governor of the State in which such region, or part of a region, is located may redesignate from time to time the boundaries of so much of such air quality control region as is located within such State only with the approval of the Administrator and with the consent of all Governors of all States which the Administrator determines may be significantly affected.

(3) No compliance date extension granted under section 7413(d)(5)[1] of this title (relating to coal conversion) shall cease to be effective by reason of the regional limitation provided in section 7413(d)(5)[1] of this title if the violation of such limitation is due solely to a redesignation of a region under this subsection.

(July 14, 1955, ch. 360, title I, § 107, as added Pub. L. 91–604, § 4(a), Dec. 31, 1970, 84 Stat. 1678; amended Pub. L. 95–95, title I, § 103, Aug. 7, 1977, 91 Stat. 687; Pub. L. 101–549, title I, § 101(a), Nov. 15, 1990, 104 Stat. 2399; Pub. L. 108–199, div. G, title IV, § 425(a), Jan. 23, 2004, 118 Stat. 417.)

Editorial Notes

References in Text

Section 7413 of this title, referred to in subsec. (e)(3), was amended generally by Pub. L. 101–549, title VII, § 701, Nov. 15, 1990, 104 Stat. 2672, and, as so amended, subsec. (d) of section 7413 no longer relates to final compliance orders.

Codification

Section was formerly classified to section 1857c–2 of this title.

[1] See References in Text note below.

PRIOR PROVISIONS

A prior section 107 of act July 14, 1955, as added Nov. 21, 1967, Pub. L. 90–148, §2, 81 Stat. 490, related to air quality control regions and was classified to section 1857c–2 of this title, prior to repeal by Pub. L. 91–604.

Another prior section 107 of act July 14, 1955, as added Dec. 17, 1963, Pub. L. 88–206, §1, 77 Stat. 399, was renumbered section 111 by Pub. L. 90–148 and is classified to section 7411 of this title.

AMENDMENTS

2004—Subsec. (d)(6), (7). Pub. L. 108–199 added pars. (6) and (7).

1990—Subsec. (d). Pub. L. 101–549 amended subsec. (d) generally, substituting present provisions for provisions which required States to submit lists of regions not in compliance on Aug. 7, 1977, with certain air quality standards to be submitted to the Administrator, and which authorized States to revise and resubmit such lists from time to time.

1977—Subsecs. (d), (e). Pub. L. 95–95 added subsecs. (d) and (e).

Statutory Notes and Related Subsidiaries

EFFECTIVE DATE OF 1977 AMENDMENT

Amendment by Pub. L. 95–95 effective Aug. 7, 1977, except as otherwise expressly provided, see section 406(d) of Pub. L. 95–95, set out as a note under section 7401 of this title.

OZONE AND PARTICULATE MATTER STANDARDS

Pub. L. 108–199, div. G, title IV, §425(b), Jan. 23, 2004, 118 Stat. 417, provided that: ''Except as provided in paragraphs (6) and (7) of section 107(d) of the Clean Air Act [subsec. (d)(6), (7) of this section] (as added by subsection (a)), section 6101, subsections (a) and (b) of section 6102, and section 6103 of the Transportation Equity Act for the 21st Century [Pub. L. 105–178] (42 U.S.C. 7407 note; 112 Stat. 463), as in effect on the day before the date of enactment of this Act [Jan. 23, 2004], shall remain in effect.''

Pub. L. 105–178, title VI, June 9, 1998, 112 Stat. 463, as amended by Pub. L. 109–59, title VI, §6012(a), Aug. 10, 2005, 119 Stat. 1882, provided that:

''SEC. 6101. FINDINGS AND PURPOSE.

''(a) The Congress finds that—

''(1) there is a lack of air quality monitoring data for fine particle levels, measured as $PM_{2.5}$, in the United States and the States should receive full funding for the monitoring efforts;

''(2) such data would provide a basis for designating areas as attainment or nonattainment for any $PM_{2.5}$ national ambient air quality standards pursuant to the standards promulgated in July 1997;

''(3) the President of the United States directed the Administrator of the Environmental Protection Agency (referred to in this title as the 'Administrator') in a memorandum dated July 16, 1997, to complete the next periodic review of the particulate matter national ambient air quality standards by July 2002 in order to determine 'whether to revise or maintain the standards';

''(4) the Administrator has stated that 3 years of air quality monitoring data for fine particle levels, measured as $PM_{2.5}$ and performed in accordance with any applicable Federal reference methods, is appropriate for designating areas as attainment or nonattainment pursuant to the July 1997 promulgated standards; and

''(5) the Administrator has acknowledged that in drawing boundaries for attainment and nonattainment areas for the July 1997 ozone national air quality standards, Governors would benefit from considering implementation guidance from EPA on drawing area boundaries.

''(b) The purposes of this title are—

''(1) to ensure that 3 years of air quality monitoring data regarding fine particle levels are gathered for use in the determination of area attainment or nonattainment designations respecting any $PM_{2.5}$ national ambient air quality standards;

''(2) to ensure that the Governors have adequate time to consider implementation guidance from EPA on drawing area boundaries prior to submitting area designations respecting the July 1997 ozone national ambient air quality standards;

''(3) to ensure that the schedule for implementation of the July 1997 revisions of the ambient air quality standards for particulate matter and the schedule for the Environmental Protection Agency's visibility regulations related to regional haze are consistent with the timetable for implementation of such particulate matter standards as set forth in the President's Implementation Memorandum dated July 16, 1997.

''SEC. 6102. PARTICULATE MATTER MONITORING PROGRAM.

''(a) Through grants under section 103 of the Clean Air Act [42 U.S.C. 7403] the Administrator of the Environmental Protection Agency shall use appropriated funds no later than fiscal year 2000 to fund 100 percent of the cost of the establishment, purchase, operation and maintenance of a $PM_{2.5}$ monitoring network necessary to implement the national ambient air quality standards for $PM_{2.5}$ under section 109 of the Clean Air Act [42 U.S.C. 7409]. This implementation shall not result in a diversion or reprogramming of funds from other Federal, State or local Clean Air Act activities. Any funds previously diverted or reprogrammed from section 105 Clean Air Act [42 U.S.C. 7405] grants for $PM_{2.5}$ monitors must be restored to State or local air programs in fiscal year 1999.

''(b) EPA and the States, consistent with their respective authorities under the Clean Air Act [42 U.S.C. 7401 et seq.], shall ensure that the national network (designated in subsection (a)) which consists of the $PM_{2.5}$ monitors necessary to implement the national ambient air quality standards is established by December 31, 1999.

''(c)(1) The Governors shall be required to submit designations referred to in section 107(d)(1) of the Clean Air Act [42 U.S.C. 7407(d)(1)] for each area following promulgation of the July 1997 $PM_{2.5}$ national ambient air quality standard within 1 year after receipt of 3 years of air quality monitoring data performed in accordance with any applicable Federal reference methods for the relevant areas. Only data from the monitoring network designated in subsection (a) and other Federal reference method $PM_{2.5}$ monitors shall be considered for such designations. Nothing in the previous sentence shall be construed as affecting the Governor's authority to designate an area initially as nonattainment, and the Administrator's authority to promulgate the designation of an area as nonattainment, under section 107(d)(1) of the Clean Air Act, based on its contribution to ambient air quality in a nearby nonattainment area.

''(2) For any area designated as nonattainment for the July 1997 $PM_{2.5}$ national ambient air quality standard in accordance with the schedule set forth in this section, notwithstanding the time limit prescribed in paragraph (2) of section 169B(e) of the Clean Air Act [42 U.S.C. 7492(e)(2)], the Administrator shall require State implementation plan revisions referred to in such paragraph (2) to be submitted at the same time as State implementation plan revisions referred to in section 172 of the Clean Air Act [42 U.S.C. 7502] implementing the revised national ambient air quality standard for fine particulate matter are required to be submitted. For any area designated as attainment or unclassifiable for such standard, the Administrator shall require the State implementation plan revisions referred to in such paragraph (2) to be submitted 1 year after the area has been so designated. The preceding provisions of this paragraph shall not preclude the implementation of the agreements and recommendations set forth in the Grand Canyon Visibility Transport Commission Report dated June 1996.

"(d) The Administrator shall promulgate the designations referred to in section 107(d)(1) of the Clean Air Act [42 U.S.C. 7407(d)(1)] for each area following promulgation of the July 1997 $PM_{2.5}$ national ambient air quality standard by the earlier of 1 year after the initial designations required under subsection (c)(1) are required to be submitted or December 31, 2005.

"(e) FIELD STUDY.—Not later than 2 years after the date of enactment of the SAFETEA–LU [Aug. 10, 2005], the Administrator shall—

"(1) conduct a field study of the ability of the $PM_{2.5}$ Federal Reference Method to differentiate those particles that are larger than 2.5 micrometers in diameter;

"(2) develop a Federal reference method to measure directly particles that are larger than 2.5 micrometers in diameter without reliance on subtracting from coarse particle measurements those particles that are equal to or smaller than 2.5 micrometers in diameter;

"(3) develop a method of measuring the composition of coarse particles; and

"(4) submit a report on the study and responsibilities of the Administrator under paragraphs (1) through (3) to—

"(A) the Committee on Energy and Commerce of the House of Representatives; and

"(B) the Committee on Environment and Public Works of the Senate.

"SEC. 6103. OZONE DESIGNATION REQUIREMENTS.

"(a) The Governors shall be required to submit the designations referred to in section 107(d)(1) of the Clean Air Act [42 U.S.C. 7407(d)(1)] within 2 years following the promulgation of the July 1997 ozone national ambient air quality standards.

"(b) The Administrator shall promulgate final designations no later than 1 year after the designations required under subsection (a) are required to be submitted.

"SEC. 6104. ADDITIONAL PROVISIONS.

"Nothing in sections 6101 through 6103 shall be construed by the Administrator of Environmental Protection Agency or any court, State, or person to affect any pending litigation or to be a ratification of the ozone or $PM_{2.5}$ standards."

PENDING ACTIONS AND PROCEEDINGS

Suits, actions, and other proceedings lawfully commenced by or against the Administrator or any other officer or employee of the United States in his official capacity or in relation to the discharge of his official duties under act July 14, 1955, the Clean Air Act, as in effect immediately prior to the enactment of Pub. L. 95–95 [Aug. 7, 1977], not to abate by reason of the taking effect of Pub. L. 95–95, see section 406(a) of Pub. L. 95–95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

MODIFICATION OR RESCISSION OF RULES, REGULATIONS, ORDERS, DETERMINATIONS, CONTRACTS, CERTIFICATIONS, AUTHORIZATIONS, DELEGATIONS, AND OTHER ACTIONS

All rules, regulations, orders, determinations, contracts, certifications, authorizations, delegations, or other actions duly issued, made, or taken by or pursuant to act July 14, 1955, the Clean Air Act, as in effect immediately prior to the date of enactment of Pub. L. 95–95 [Aug. 7, 1977] to continue in full force and effect until modified or rescinded in accordance with act July 14, 1955, as amended by Pub. L. 95–95 [this chapter], see section 406(b) of Pub. L. 95–95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

§ 7408. Air quality criteria and control techniques

(a) Air pollutant list; publication and revision by Administrator; issuance of air quality criteria for air pollutants

(1) For the purpose of establishing national primary and secondary ambient air quality standards, the Administrator shall within 30 days after December 31, 1970, publish, and shall from time to time thereafter revise, a list which includes each air pollutant—

(A) emissions of which, in his judgment, cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare;

(B) the presence of which in the ambient air results from numerous or diverse mobile or stationary sources; and

(C) for which air quality criteria had not been issued before December 31, 1970 but for which he plans to issue air quality criteria under this section.

(2) The Administrator shall issue air quality criteria for an air pollutant within 12 months after he has included such pollutant in a list under paragraph (1). Air quality criteria for an air pollutant shall accurately reflect the latest scientific knowledge useful in indicating the kind and extent of all identifiable effects on public health or welfare which may be expected from the presence of such pollutant in the ambient air, in varying quantities. The criteria for an air pollutant, to the extent practicable, shall include information on—

(A) those variable factors (including atmospheric conditions) which of themselves or in combination with other factors may alter the effects on public health or welfare of such air pollutant;

(B) the types of air pollutants which, when present in the atmosphere, may interact with such pollutant to produce an adverse effect on public health or welfare; and

(C) any known or anticipated adverse effects on welfare.

(b) Issuance by Administrator of information on air pollution control techniques; standing consulting committees for air pollutants; establishment; membership

(1) Simultaneously with the issuance of criteria under subsection (a), the Administrator shall, after consultation with appropriate advisory committees and Federal departments and agencies, issue to the States and appropriate air pollution control agencies information on air pollution control techniques, which information shall include data relating to the cost of installation and operation, energy requirements, emission reduction benefits, and environmental impact of the emission control technology. Such information shall include such data as are available on available technology and alternative methods of prevention and control of air pollution. Such information shall also include data on alternative fuels, processes, and operating methods which will result in elimination or significant reduction of emissions.

(2) In order to assist in the development of information on pollution control techniques, the

amended Pub. L. 95–95, title I, §106, Aug. 7, 1977, 91 Stat. 691.)

CODIFICATION

Section was formerly classified to section 1857c–4 of this title.

PRIOR PROVISIONS

A prior section 109 of act July 14, 1955, was renumbered section 116 by Pub. L. 91–604 and is classified to section 7416 of this title.

AMENDMENTS

1977—Subsec. (c). Pub. L. 95–95, §106(b), added subsec. (c).

Subsec. (d). Pub. L. 95–95, §106(a), added subsec. (d).

EFFECTIVE DATE OF 1977 AMENDMENT

Amendment by Pub. L. 95–95 effective Aug. 7, 1977, except as otherwise expressly provided, see section 406(d) of Pub. L. 95–95, set out as a note under section 7401 of this title.

MODIFICATION OR RESCISSION OF RULES, REGULATIONS, ORDERS, DETERMINATIONS, CONTRACTS, CERTIFICATIONS, AUTHORIZATIONS, DELEGATIONS, AND OTHER ACTIONS

All rules, regulations, orders, determinations, contracts, certifications, authorizations, delegations, or other actions duly issued, made, or taken by or pursuant to act July 14, 1955, the Clean Air Act, as in effect immediately prior to the date of enactment of Pub. L. 95–95 [Aug. 7, 1977] to continue in full force and effect until modified or rescinded in accordance with act July 14, 1955, as amended by Pub. L. 95–95 [this chapter], see section 406(b) of Pub. L. 95–95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

TERMINATION OF ADVISORY COMMITTEES

Advisory committees established after Jan. 5, 1973, to terminate not later than the expiration of the 2-year period beginning on the date of their establishment, unless, in the case of a committee established by the President or an officer of the Federal Government, such committee is renewed by appropriate action prior to the expiration of such 2-year period, or in the case of a committee established by the Congress, its duration is otherwise provided for by law. See section 14 of Pub. L. 92–463, Oct. 6, 1972, 86 Stat. 776, set out in the Appendix to Title 5, Government Organization and Employees.

ROLE OF SECONDARY STANDARDS

Pub. L. 101–549, title VIII, §817, Nov. 15, 1990, 104 Stat. 2697, provided that:

''(a) REPORT.—The Administrator shall request the National Academy of Sciences to prepare a report to the Congress on the role of national secondary ambient air quality standards in protecting welfare and the environment. The report shall:

''(1) include information on the effects on welfare and the environment which are caused by ambient concentrations of pollutants listed pursuant to section 108 [42 U.S.C. 7408] and other pollutants which may be listed;

''(2) estimate welfare and environmental costs incurred as a result of such effects;

''(3) examine the role of secondary standards and the State implementation planning process in preventing such effects;

''(4) determine ambient concentrations of each such pollutant which would be adequate to protect welfare and the environment from such effects;

''(5) estimate the costs and other impacts of meeting secondary standards; and

''(6) consider other means consistent with the goals and objectives of the Clean Air Act [42 U.S.C. 7401 et seq.] which may be more effective than secondary standards in preventing or mitigating such effects.

''(b) SUBMISSION TO CONGRESS; COMMENTS; AUTHORIZATION.—(1) The report shall be transmitted to the Congress not later than 3 years after the date of enactment of the Clean Air Act Amendments of 1990 [Nov. 15, 1990].

''(2) At least 90 days before issuing a report the Administrator shall provide an opportunity for public comment on the proposed report. The Administrator shall include in the final report a summary of the comments received on the proposed report.

''(3) There are authorized to be appropriated such sums as are necessary to carry out this section.''

§7410. State implementation plans for national primary and secondary ambient air quality standards

(a) Adoption of plan by State; submission to Administrator; content of plan; revision; new sources; indirect source review program; supplemental or intermittent control systems

(1) Each State shall, after reasonable notice and public hearings, adopt and submit to the Administrator, within 3 years (or such shorter period as the Administrator may prescribe) after the promulgation of a national primary ambient air quality standard (or any revision thereof) under section 7409 of this title for any air pollutant, a plan which provides for implementation, maintenance, and enforcement of such primary standard in each air quality control region (or portion thereof) within such State. In addition, such State shall adopt and submit to the Administrator (either as a part of a plan submitted under the preceding sentence or separately) within 3 years (or such shorter period as the Administrator may prescribe) after the promulgation of a national ambient air quality secondary standard (or revision thereof), a plan which provides for implementation, maintenance, and enforcement of such secondary standard in each air quality control region (or portion thereof) within such State. Unless a separate public hearing is provided, each State shall consider its plan implementing such secondary standard at the hearing required by the first sentence of this paragraph.

(2) Each implementation plan submitted by a State under this chapter shall be adopted by the State after reasonable notice and public hearing. Each such plan shall—

(A) include enforceable emission limitations and other control measures, means, or techniques (including economic incentives such as fees, marketable permits, and auctions of emissions rights), as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements of this chapter;

(B) provide for establishment and operation of appropriate devices, methods, systems, and procedures necessary to—

(i) monitor, compile, and analyze data on ambient air quality, and

(ii) upon request, make such data available to the Administrator;

(C) include a program to provide for the enforcement of the measures described in subparagraph (A), and regulation of the modification and construction of any stationary source within the areas covered by the plan as necessary to assure that national ambient air quality standards are achieved, including a permit program as required in parts C and D of this subchapter;

(D) contain adequate provisions—

(i) prohibiting, consistent with the provisions of this subchapter, any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—

(I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard, or

(II) interfere with measures required to be included in the applicable implementation plan for any other State under part C of this subchapter to prevent significant deterioration of air quality or to protect visibility,

(ii) insuring compliance with the applicable requirements of sections 7426 and 7415 of this title (relating to interstate and international pollution abatement);

(E) provide (i) necessary assurances that the State (or, except where the Administrator deems inappropriate, the general purpose local government or governments, or a regional agency designated by the State or general purpose local governments for such purpose) will have adequate personnel, funding, and authority under State (and, as appropriate, local) law to carry out such implementation plan (and is not prohibited by any provision of Federal or State law from carrying out such implementation plan or portion thereof), (ii) requirements that the State comply with the requirements respecting State boards under section 7428 of this title, and (iii) necessary assurances that, where the State has relied on a local or regional government, agency, or instrumentality for the implementation of any plan provision, the State has responsibility for ensuring adequate implementation of such plan provision;

(F) require, as may be prescribed by the Administrator—

(i) the installation, maintenance, and replacement of equipment, and the implementation of other necessary steps, by owners or operators of stationary sources to monitor emissions from such sources,

(ii) periodic reports on the nature and amounts of emissions and emissions-related data from such sources, and

(iii) correlation of such reports by the State agency with any emission limitations or standards established pursuant to this chapter, which reports shall be available at reasonable times for public inspection;

(G) provide for authority comparable to that in section 7603 of this title and adequate contingency plans to implement such authority;

(H) provide for revision of such plan—

(i) from time to time as may be necessary to take account of revisions of such national primary or secondary ambient air quality standard or the availability of improved or more expeditious methods of attaining such standard, and

(ii) except as provided in paragraph (3)(C), whenever the Administrator finds on the basis of information available to the Administrator that the plan is substantially inadequate to attain the national ambient air quality standard which it implements or to otherwise comply with any additional requirements established under this chapter;

(I) in the case of a plan or plan revision for an area designated as a nonattainment area, meet the applicable requirements of part D of this subchapter (relating to nonattainment areas);

(J) meet the applicable requirements of section 7421 of this title (relating to consultation), section 7427 of this title (relating to public notification), and part C of this subchapter (relating to prevention of significant deterioration of air quality and visibility protection);

(K) provide for—

(i) the performance of such air quality modeling as the Administrator may prescribe for the purpose of predicting the effect on ambient air quality of any emissions of any air pollutant for which the Administrator has established a national ambient air quality standard, and

(ii) the submission, upon request, of data related to such air quality modeling to the Administrator;

(L) require the owner or operator of each major stationary source to pay to the permitting authority, as a condition of any permit required under this chapter, a fee sufficient to cover—

(i) the reasonable costs of reviewing and acting upon any application for such a permit, and

(ii) if the owner or operator receives a permit for such source, the reasonable costs of implementing and enforcing the terms and conditions of any such permit (not including any court costs or other costs associated with any enforcement action),

until such fee requirement is superseded with respect to such sources by the Administrator's approval of a fee program under subchapter V of this chapter; and

(M) provide for consultation and participation by local political subdivisions affected by the plan.

(3)(A) Repealed. Pub. L. 101–549, title I, §101(d)(1), Nov. 15, 1990, 104 Stat. 2409.

(B) As soon as practicable, the Administrator shall, consistent with the purposes of this chapter and the Energy Supply and Environmental Coordination Act of 1974 [15 U.S.C. 791 et seq.], review each State's applicable implementation plans and report to the State on whether such plans can be revised in relation to fuel burning stationary sources (or persons supplying fuel to such sources) without interfering with the attainment and maintenance of any national ambient air quality standard within the period permitted in this section. If the Administrator determines that any such plan can be revised, he shall notify the State that a plan revision may be submitted by the State. Any plan revision which is submitted by the State shall, after public notice and opportunity for public hearing, be approved by the Administrator if the revision relates only to fuel burning stationary sources (or persons supplying fuel to such sources), and the plan as revised complies with paragraph (2) of this subsection. The Administrator shall approve or disapprove any revision no later than three months after its submission.

(C) Neither the State, in the case of a plan (or portion thereof) approved under this subsection, nor the Administrator, in the case of a plan (or portion thereof) promulgated under subsection (c) of this section, shall be required to revise an applicable implementation plan because one or more exemptions under section 7418 of this title (relating to Federal facilities), enforcement orders under section 7413(d)[1] of this title, suspensions under subsection (f) or (g) of this section (relating to temporary energy or economic authority), orders under section 7419 of this title (relating to primary nonferrous smelters), or extensions of compliance in decrees entered under section 7413(e)[1] of this title (relating to iron- and steel-producing operations) have been granted, if such plan would have met the requirements of this section if no such exemptions, orders, or extensions had been granted.

(4) Repealed. Pub. L. 101–549, title I, § 101(d)(2), Nov. 15, 1990, 104 Stat. 2409.

(5)(A)(i) Any State may include in a State implementation plan, but the Administrator may not require as a condition of approval of such plan under this section, any indirect source review program. The Administrator may approve and enforce, as part of an applicable implementation plan, an indirect source review program which the State chooses to adopt and submit as part of its plan.

(ii) Except as provided in subparagraph (B), no plan promulgated by the Administrator shall include any indirect source review program for any air quality control region, or portion thereof.

(iii) Any State may revise an applicable implementation plan approved under this subsection to suspend or revoke any such program included in such plan, provided that such plan meets the requirements of this section.

(B) The Administrator shall have the authority to promulgate, implement and enforce regulations under subsection (c) of this section respecting indirect source review programs which apply only to federally assisted highways, airports, and other major federally assisted indirect sources and federally owned or operated indirect sources.

(C) For purposes of this paragraph, the term ''indirect source'' means a facility, building, structure, installation, real property, road, or highway which attracts, or may attract, mobile sources of pollution. Such term includes parking lots, parking garages, and other facilities subject to any measure for management of parking supply (within the meaning of subsection (c)(2)(D)(ii) of this section), including regulation of existing off-street parking but such term does not include new or existing on-street parking. Direct emissions sources or facilities at, within, or associated with, any indirect source shall not be deemed indirect sources for the purpose of this paragraph.

(D) For purposes of this paragraph the term ''indirect source review program'' means the facility-by-facility review of indirect sources of air pollution, including such measures as are necessary to assure, or assist in assuring, that a new or modified indirect source will not attract mobile sources of air pollution, the emissions from which would cause or contribute to air pollution concentrations—

(i) exceeding any national primary ambient air quality standard for a mobile source-related air pollutant after the primary standard attainment date, or

(ii) preventing maintenance of any such standard after such date.

(E) For purposes of this paragraph and paragraph (2)(B), the term ''transportation control measure'' does not include any measure which is an ''indirect source review program''.

(6) No State plan shall be treated as meeting the requirements of this section unless such plan provides that in the case of any source which uses a supplemental, or intermittent control system for purposes of meeting the requirements of an order under section 7413(d)[1] of this title or section 7419 of this title (relating to primary nonferrous smelter orders), the owner or operator of such source may not temporarily reduce the pay of any employee by reason of the use of such supplemental or intermittent or other dispersion dependent control system.

(b) Extension of period for submission of plans

The Administrator may, wherever he determines necessary, extend the period for submission of any plan or portion thereof which implements a national secondary ambient air quality standard for a period not to exceed 18 months from the date otherwise required for submission of such plan.

(c) Preparation and publication by Administrator of proposed regulations setting forth implementation plan; transportation regulations study and report; parking surcharge; suspension authority; plan implementation

(1) The Administrator shall promulgate a Federal implementation plan at any time within 2 years after the Administrator—

(A) finds that a State has failed to make a required submission or finds that the plan or plan revision submitted by the State does not satisfy the minimum criteria established under subsection (k)(1)(A) of this section, or

(B) disapproves a State implementation plan submission in whole or in part,

unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal implementation plan.

(2)(A) Repealed. Pub. L. 101–549, title I, § 101(d)(3)(A), Nov. 15, 1990, 104 Stat. 2409.

(B) No parking surcharge regulation may be required by the Administrator under paragraph (1) of this subsection as a part of an applicable implementation plan. All parking surcharge regulations previously required by the Administrator shall be void upon June 22, 1974. This subparagraph shall not prevent the Administrator

[1] See References in Text note below.

from approving parking surcharges if they are adopted and submitted by a State as part of an applicable implementation plan. The Administrator may not condition approval of any implementation plan submitted by a State on such plan's including a parking surcharge regulation.

(C) Repealed. Pub. L. 101–549, title I, § 101(d)(3)(B), Nov. 15, 1990, 104 Stat. 2409.

(D) For purposes of this paragraph—

(i) The term ''parking surcharge regulation'' means a regulation imposing or requiring the imposition of any tax, surcharge, fee, or other charge on parking spaces, or any other area used for the temporary storage of motor vehicles.

(ii) The term ''management of parking supply'' shall include any requirement providing that any new facility containing a given number of parking spaces shall receive a permit or other prior approval, issuance of which is to be conditioned on air quality considerations.

(iii) The term ''preferential bus/carpool lane'' shall include any requirement for the setting aside of one or more lanes of a street or highway on a permanent or temporary basis for the exclusive use of buses or carpools, or both.

(E) No standard, plan, or requirement, relating to management of parking supply or preferential bus/carpool lanes shall be promulgated after June 22, 1974, by the Administrator pursuant to this section, unless such promulgation has been subjected to at least one public hearing which has been held in the area affected and for which reasonable notice has been given in such area. If substantial changes are made following public hearings, one or more additional hearings shall be held in such area after such notice.

(3) Upon application of the chief executive officer of any general purpose unit of local government, if the Administrator determines that such unit has adequate authority under State or local law, the Administrator may delegate to such unit the authority to implement and enforce within the jurisdiction of such unit any part of a plan promulgated under this subsection. Nothing in this paragraph shall prevent the Administrator from implementing or enforcing any applicable provision of a plan promulgated under this subsection.

(4) Repealed. Pub. L. 101–549, title I, § 101(d)(3)(C), Nov. 15, 1990, 104 Stat. 2409.

(5)(A) Any measure in an applicable implementation plan which requires a toll or other charge for the use of a bridge located entirely within one city shall be eliminated from such plan by the Administrator upon application by the Governor of the State, which application shall include a certification by the Governor that he will revise such plan in accordance with subparagraph (B).

(B) In the case of any applicable implementation plan with respect to which a measure has been eliminated under subparagraph (A), such plan shall, not later than one year after August 7, 1977, be revised to include comprehensive measures to:

(i) establish, expand, or improve public transportation measures to meet basic transportation needs, as expeditiously as is practicable; and

(ii) implement transportation control measures necessary to attain and maintain national ambient air quality standards,

and such revised plan shall, for the purpose of implementing such comprehensive public transportation measures, include requirements to use (insofar as is necessary) Federal grants, State or local funds, or any combination of such grants and funds as may be consistent with the terms of the legislation providing such grants and funds. Such measures shall, as a substitute for the tolls or charges eliminated under subparagraph (A), provide for emissions reductions equivalent to the reductions which may reasonably be expected to be achieved through the use of the tolls or charges eliminated.

(C) Any revision of an implementation plan for purposes of meeting the requirements of subparagraph (B) shall be submitted in coordination with any plan revision required under part D of this subchapter.

(d), (e) Repealed. Pub. L. 101–549, title I, § 101(d)(4), (5), Nov. 15, 1990, 104 Stat. 2409

(f) National or regional energy emergencies; determination by President

(1) Upon application by the owner or operator of a fuel burning stationary source, and after notice and opportunity for public hearing, the Governor of the State in which such source is located may petition the President to determine that a national or regional energy emergency exists of such severity that—

(A) a temporary suspension of any part of the applicable implementation plan or of any requirement under section 7651j of this title (concerning excess emissions penalties or offsets) may be necessary, and

(B) other means of responding to the energy emergency may be inadequate.

Such determination shall not be delegable by the President to any other person. If the President determines that a national or regional energy emergency of such severity exists, a temporary emergency suspension of any part of an applicable implementation plan or of any requirement under section 7651j of this title (concerning excess emissions penalties or offsets) adopted by the State may be issued by the Governor of any State covered by the President's determination under the condition specified in paragraph (2) and may take effect immediately.

(2) A temporary emergency suspension under this subsection shall be issued to a source only if the Governor of such State finds that—

(A) there exists in the vicinity of such source a temporary energy emergency involving high levels of unemployment or loss of necessary energy supplies for residential dwellings; and

(B) such unemployment or loss can be totally or partially alleviated by such emergency suspension.

Not more than one such suspension may be issued for any source on the basis of the same set of circumstances or on the basis of the same emergency.

(3) A temporary emergency suspension issued by a Governor under this subsection shall re-

main in effect for a maximum of four months or such lesser period as may be specified in a disapproval order of the Administrator, if any. The Administrator may disapprove such suspension if he determines that it does not meet the requirements of paragraph (2).

(4) This subsection shall not apply in the case of a plan provision or requirement promulgated by the Administrator under subsection (c) of this section, but in any such case the President may grant a temporary emergency suspension for a four month period of any such provision or requirement if he makes the determinations and findings specified in paragraphs (1) and (2).

(5) The Governor may include in any temporary emergency suspension issued under this subsection a provision delaying for a period identical to the period of such suspension any compliance schedule (or increment of progress) to which such source is subject under section 1857c–10[2] of this title, as in effect before August 7, 1977, or section 7413(d)[2] of this title, upon a finding that such source is unable to comply with such schedule (or increment) solely because of the conditions on the basis of which a suspension was issued under this subsection.

(g) Governor's authority to issue temporary emergency suspensions

(1) In the case of any State which has adopted and submitted to the Administrator a proposed plan revision which the State determines—

(A) meets the requirements of this section, and

(B) is necessary (i) to prevent the closing for one year or more of any source of air pollution, and (ii) to prevent substantial increases in unemployment which would result from such closing, and

which the Administrator has not approved or disapproved under this section within 12 months of submission of the proposed plan revision, the Governor may issue a temporary emergency suspension of the part of the applicable implementation plan for such State which is proposed to be revised with respect to such source. The determination under subparagraph (B) may not be made with respect to a source which would close without regard to whether or not the proposed plan revision is approved.

(2) A temporary emergency suspension issued by a Governor under this subsection shall remain in effect for a maximum of four months or such lesser period as may be specified in a disapproval order of the Administrator. The Administrator may disapprove such suspension if he determines that it does not meet the requirements of this subsection.

(3) The Governor may include in any temporary emergency suspension issued under this subsection a provision delaying for a period identical to the period of such suspension any compliance schedule (or increment of progress) to which such source is subject under section 1857c–10[2] of this title as in effect before August 7, 1977, or under section 7413(d)[2] of this title upon a finding that such source is unable to comply with such schedule (or increment) solely because of the conditions on the basis of which a suspension was issued under this subsection.

[2] See References in Text note below.

(h) Publication of comprehensive document for each State setting forth requirements of applicable implementation plan

(1) Not later than 5 years after November 15, 1990, and every 3 years thereafter, the Administrator shall assemble and publish a comprehensive document for each State setting forth all requirements of the applicable implementation plan for such State and shall publish notice in the Federal Register of the availability of such documents.

(2) The Administrator may promulgate such regulations as may be reasonably necessary to carry out the purpose of this subsection.

(i) Modification of requirements prohibited

Except for a primary nonferrous smelter order under section 7419 of this title, a suspension under subsection (f) or (g) of this section (relating to emergency suspensions), an exemption under section 7418 of this title (relating to certain Federal facilities), an order under section 7413(d)[2] of this title (relating to compliance orders), a plan promulgation under subsection (c) of this section, or a plan revision under subsection (a)(3) of this section; no order, suspension, plan revision, or other action modifying any requirement of an applicable implementation plan may be taken with respect to any stationary source by the State or by the Administrator.

(j) Technological systems of continuous emission reduction on new or modified stationary sources; compliance with performance standards

As a condition for issuance of any permit required under this subchapter, the owner or operator of each new or modified stationary source which is required to obtain such a permit must show to the satisfaction of the permitting authority that the technological system of continuous emission reduction which is to be used at such source will enable it to comply with the standards of performance which are to apply to such source and that the construction or modification and operation of such source will be in compliance with all other requirements of this chapter.

(k) Environmental Protection Agency action on plan submissions

(1) Completeness of plan submissions

(A) Completeness criteria

Within 9 months after November 15, 1990, the Administrator shall promulgate minimum criteria that any plan submission must meet before the Administrator is required to act on such submission under this subsection. The criteria shall be limited to the information necessary to enable the Administrator to determine whether the plan submission complies with the provisions of this chapter.

(B) Completeness finding

Within 60 days of the Administrator's receipt of a plan or plan revision, but no later than 6 months after the date, if any, by which a State is required to submit the plan or revision, the Administrator shall determine whether the minimum criteria established pursuant to subparagraph (A) have been met. Any plan or plan revision that a State submits to the Administrator, and that has not been determined by the Administrator (by the date 6 months after receipt of the submission) to have failed to meet the minimum criteria established pursuant to subparagraph (A), shall on that date be deemed by operation of law to meet such minimum criteria.

(C) Effect of finding of incompleteness

Where the Administrator determines that a plan submission (or part thereof) does not meet the minimum criteria established pursuant to subparagraph (A), the State shall be treated as not having made the submission (or, in the Administrator's discretion, part thereof).

(2) Deadline for action

Within 12 months of a determination by the Administrator (or a determination deemed by operation of law) under paragraph (1) that a State has submitted a plan or plan revision (or, in the Administrator's discretion, part thereof) that meets the minimum criteria established pursuant to paragraph (1), if applicable (or, if those criteria are not applicable, within 12 months of submission of the plan or revision), the Administrator shall act on the submission in accordance with paragraph (3).

(3) Full and partial approval and disapproval

In the case of any submittal on which the Administrator is required to act under paragraph (2), the Administrator shall approve such submittal as a whole if it meets all of the applicable requirements of this chapter. If a portion of the plan revision meets all the applicable requirements of this chapter, the Administrator may approve the plan revision in part and disapprove the plan revision in part. The plan revision shall not be treated as meeting the requirements of this chapter until the Administrator approves the entire plan revision as complying with the applicable requirements of this chapter.

(4) Conditional approval

The Administrator may approve a plan revision based on a commitment of the State to adopt specific enforceable measures by a date certain, but not later than 1 year after the date of approval of the plan revision. Any such conditional approval shall be treated as a disapproval if the State fails to comply with such commitment.

(5) Calls for plan revisions

Whenever the Administrator finds that the applicable implementation plan for any area is substantially inadequate to attain or maintain the relevant national ambient air quality standard, to mitigate adequately the interstate pollutant transport described in section 7506a of this title or section 7511c of this title, or to otherwise comply with any requirement of this chapter, the Administrator shall require the State to revise the plan as necessary to correct such inadequacies. The Administrator shall notify the State of the inadequacies, and may establish reasonable deadlines (not to exceed 18 months after the date of such notice) for the submission of such plan revisions. Such findings and notice shall be public. Any finding under this paragraph shall, to the extent the Administrator deems appropriate, subject the State to the requirements of this chapter to which the State was subject when it developed and submitted the plan for which such finding was made, except that the Administrator may adjust any dates applicable under such requirements as appropriate (except that the Administrator may not adjust any attainment date prescribed under part D of this subchapter, unless such date has elapsed).

(6) Corrections

Whenever the Administrator determines that the Administrator's action approving, disapproving, or promulgating any plan or plan revision (or part thereof), area designation, redesignation, classification, or reclassification was in error, the Administrator may in the same manner as the approval, disapproval, or promulgation revise such action as appropriate without requiring any further submission from the State. Such determination and the basis thereof shall be provided to the State and public.

(*l*) Plan revisions

Each revision to an implementation plan submitted by a State under this chapter shall be adopted by such State after reasonable notice and public hearing. The Administrator shall not approve a revision of a plan if the revision would interfere with any applicable requirement concerning attainment and reasonable further progress (as defined in section 7501 of this title), or any other applicable requirement of this chapter.

(m) Sanctions

The Administrator may apply any of the sanctions listed in section 7509(b) of this title at any time (or at any time after) the Administrator makes a finding, disapproval, or determination under paragraphs (1) through (4), respectively, of section 7509(a) of this title in relation to any plan or plan item (as that term is defined by the Administrator) required under this chapter, with respect to any portion of the State the Administrator determines reasonable and appropriate, for the purpose of ensuring that the requirements of this chapter relating to such plan or plan item are met. The Administrator shall, by rule, establish criteria for exercising his authority under the previous sentence with respect to any deficiency referred to in section 7509(a) of this title to ensure that, during the 24-month period following the finding, disapproval, or determination referred to in section 7509(a) of this title, such sanctions are not applied on a statewide basis where one or more political subdivisions covered by the applicable implementation plan are principally responsible for such deficiency.

(n) Savings clauses

(1) Existing plan provisions

Any provision of any applicable implementation plan that was approved or promulgated by the Administrator pursuant to this section as in effect before November 15, 1990, shall remain in effect as part of such applicable implementation plan, except to the extent that a revision to such provision is approved or promulgated by the Administrator pursuant to this chapter.

(2) Attainment dates

For any area not designated nonattainment, any plan or plan revision submitted or required to be submitted by a State—

(A) in response to the promulgation or revision of a national primary ambient air quality standard in effect on November 15, 1990, or

(B) in response to a finding of substantial inadequacy under subsection (a)(2) of this section (as in effect immediately before November 15, 1990),

shall provide for attainment of the national primary ambient air quality standards within 3 years of November 15, 1990, or within 5 years of issuance of such finding of substantial inadequacy, whichever is later.

(3) Retention of construction moratorium in certain areas

In the case of an area to which, immediately before November 15, 1990, the prohibition on construction or modification of major stationary sources prescribed in subsection (a)(2)(I) of this section (as in effect immediately before November 15, 1990) applied by virtue of a finding of the Administrator that the State containing such area had not submitted an implementation plan meeting the requirements of section 7502(b)(6) of this title (relating to establishment of a permit program) (as in effect immediately before November 15, 1990) or 7502(a)(1) of this title (to the extent such requirements relate to provision for attainment of the primary national ambient air quality standard for sulfur oxides by December 31, 1982) as in effect immediately before November 15, 1990, no major stationary source of the relevant air pollutant or pollutants shall be constructed or modified in such area until the Administrator finds that the plan for such area meets the applicable requirements of section 7502(c)(5) of this title (relating to permit programs) or subpart 5 of part D of this subchapter (relating to attainment of the primary national ambient air quality standard for sulfur dioxide), respectively.

(*o*) Indian tribes

If an Indian tribe submits an implementation plan to the Administrator pursuant to section 7601(d) of this title, the plan shall be reviewed in accordance with the provisions for review set forth in this section for State plans, except as otherwise provided by regulation promulgated pursuant to section 7601(d)(2) of this title. When such plan becomes effective in accordance with the regulations promulgated under section 7601(d) of this title, the plan shall become applicable to all areas (except as expressly provided otherwise in the plan) located within the exterior boundaries of the reservation, notwithstanding the issuance of any patent and including rights-of-way running through the reservation.

(p) Reports

Any State shall submit, according to such schedule as the Administrator may prescribe, such reports as the Administrator may require relating to emission reductions, vehicle miles traveled, congestion levels, and any other information the Administrator may deem necessary to assess the development[3] effectiveness, need for revision, or implementation of any plan or plan revision required under this chapter.

(July 14, 1955, ch. 360, title I, § 110, as added Pub. L. 91–604, § 4(a), Dec. 31, 1970, 84 Stat. 1680; amended Pub. L. 93–319, § 4, June 22, 1974, 88 Stat. 256; Pub. L. 95–95, title I, §§ 107, 108, Aug. 7, 1977, 91 Stat. 691, 693; Pub. L. 95–190, § 14(a)(1)–(6), Nov. 16, 1977, 91 Stat. 1399; Pub. L. 97–23, § 3, July 17, 1981, 95 Stat. 142; Pub. L. 101–549, title I, §§ 101(b)–(d), 102(h), 107(c), 108(d), title IV, § 412, Nov. 15, 1990, 104 Stat. 2404–2408, 2422, 2464, 2466, 2634.)

REFERENCES IN TEXT

The Energy Supply and Environmental Coordination Act of 1974, referred to in subsec. (a)(3)(B), is Pub. L. 93–319, June 22, 1974, 88 Stat. 246, as amended, which is classified principally to chapter 16C (§ 791 et seq.) of Title 15, Commerce and Trade. For complete classification of this Act to the Code, see Short Title note set out under section 791 of Title 15 and Tables.

Section 7413 of this title, referred to in subsecs. (a)(3)(C), (6), (f)(5), (g)(3), and (i), was amended generally by Pub. L. 101–549, title VII, § 701, Nov. 15, 1990, 104 Stat. 2672, and, as so amended, subsecs. (d) and (e) of section 7413 no longer relates to final compliance orders and steel industry compliance extension, respectively.

Section 1857c–10 of this title, as in effect before August 7, 1977, referred to in subsecs. (f)(5) and (g)(3), was in the original "section 119, as in effect before the date of the enactment of this paragraph", meaning section 119 of act July 14, 1955, ch. 360, title I, as added June 22, 1974, Pub. L. 93–319, § 3, 88 Stat. 248, (which was classified to section 1857c–10 of this title) as in effect prior to the enactment of subsecs. (f)(5) and (g)(3) of this section by Pub. L. 95–95, § 107, Aug. 7, 1977, 91 Stat. 691, effective Aug. 7, 1977. Section 112(b)(1) of Pub. L. 95–95 repealed section 119 of act July 14, 1955, ch. 360, title I, as added by Pub. L. 93–319, and provided that all references to such section 119 in any subsequent enactment which supersedes Pub. L. 93–319 shall be construed to refer to section 113(d) of the Clean Air Act and to paragraph (5) thereof in particular which is classified to section 7413(d)(5) of this title. Section 7413 of this title was subsequently amended generally by Pub. L. 101–549, title VII, § 701, Nov. 15, 1990, 104 Stat. 2672, see note above. Section 117(b) of Pub. L. 95–95 added a new section 119 of act July 14, 1955, which is classified to section 7419 of this title.

CODIFICATION

Section was formerly classified to section 1857c–5 of this title.

PRIOR PROVISIONS

A prior section 110 of act July 14, 1955, was renumbered section 117 by Pub. L. 91–604 and is classified to section 7417 of this title.

AMENDMENTS

1990—Subsec. (a)(1). Pub. L. 101–549, § 101(d)(8), substituted "3 years (or such shorter period as the Administrator may prescribe)" for "nine months" in two places.

[3] So in original. Probably should be followed by a comma.

Subsec. (a)(2). Pub. L. 101–549, § 101(b), amended par. (2) generally, substituting present provisions for provisions setting the time within which the Administrator was to approve or disapprove a plan or portion thereof and listing the conditions under which the plan or portion thereof was to be approved after reasonable notice and hearing.

Subsec. (a)(3)(A). Pub. L. 101–549, § 101(d)(1), struck out subpar. (A) which directed Administrator to approve any revision of an implementation plan if it met certain requirements and had been adopted by the State after reasonable notice and public hearings.

Subsec. (a)(3)(D). Pub. L. 101–549, § 101(d)(1), struck out subpar. (D) which directed that certain implementation plans be revised to include comprehensive measures and requirements.

Subsec. (a)(4). Pub. L. 101–549, § 101(d)(2), struck out par. (4) which set forth requirements for review procedure.

Subsec. (c)(1). Pub. L. 101–549, § 102(h), amended par. (1) generally, substituting present provisions for provisions relating to preparation and publication of regulations setting forth an implementation plan, after opportunity for a hearing, upon failure of a State to make required submission or revision.

Subsec. (c)(2)(A). Pub. L. 101–549, § 101(d)(3)(A), struck out subpar. (A) which required a study and report on necessity of parking surcharge, management of parking supply, and preferential bus/carpool lane regulations to achieve and maintain national primary ambient air quality standards.

Subsec. (c)(2)(C). Pub. L. 101–549, § 101(d)(3)(B), struck out subpar. (C) which authorized suspension of certain regulations and requirements relating to management of parking supply.

Subsec. (c)(4). Pub. L. 101–549, § 101(d)(3)(C), struck out par. (4) which permitted Governors to temporarily suspend measures in implementation plans relating to retrofits, gas rationing, and reduction of on-street parking.

Subsec. (c)(5)(B). Pub. L. 101–549, § 101(d)(3)(D), struck out ''(including the written evidence required by part D),'' after ''include comprehensive measures''.

Subsec. (d). Pub. L. 101–549, § 101(d)(4), struck out subsec. (d) which defined an applicable implementation plan for purposes of this chapter.

Subsec. (e). Pub. L. 101–549, § 101(d)(5), struck out subsec. (e) which permitted an extension of time for attainment of a national primary ambient air quality standard.

Subsec. (f)(1). Pub. L. 101–549, § 412, inserted ''or of any requirement under section 7651j of this title (concerning excess emissions penalties or offsets)'' in subpar. (A) and in last sentence.

Subsec. (g)(1). Pub. L. 101–549, § 101(d)(6), substituted ''12 months of submission of the proposed plan revision'' for ''the required four month period'' in closing provisions.

Subsec. (h)(1). Pub. L. 101–549, § 101(d)(7), substituted ''5 years after November 15, 1990, and every three years thereafter'' for ''one year after August 7, 1977, and annually thereafter'' and struck out at end ''Each such document shall be revised as frequently as practicable but not less often than annually.''

Subsecs. (k) to (n). Pub. L. 101–549, § 101(c), added subsecs. (k) to (n).

Subsec. (*o*). Pub. L. 101–549, § 107(c), added subsec. (*o*).

Subsec. (p). Pub. L. 101–549, § 108(d), added subsec. (p).

1981—Subsec. (a)(3)(C). Pub. L. 97–23 inserted reference to extensions of compliance in decrees entered under section 7413(e) of this title (relating to iron- and steel-producing operations).

1977—Subsec. (a)(2)(A). Pub. L. 95–95, § 108(a)(1), substituted ''(A) except as may be provided in subparagraph (I)(i) in the case of a plan'' for ''(A)(i) in the case of a plan''.

Subsec. (a)(2)(B). Pub. L. 95–95, § 108(a)(2), substituted ''transportation controls, air quality maintenance plans, and preconstruction review of direct sources of air pollution as provided in subparagraph (D)'' for ''land use and transportation controls''.

Subsec. (a)(2)(D). Pub. L. 95–95, § 108(a)(3), substituted ''it includes a program to provide for the enforcement of emission limitations and regulation of the modification, construction, and operation of any stationary source, including a permit program as required in parts C and D and a permit or equivalent program for any major emitting facility, within such region as necessary to assure (i) that national ambient air quality standards are achieved and maintained, and (ii) a procedure'' for ''it includes a procedure''.

Subsec. (a)(2)(E). Pub. L. 95–95, § 108(a)(4), substituted ''it contains adequate provisions (i) prohibiting any stationary source within the State from emitting any air pollutant in amounts which will (I) prevent attainment or maintenance by any other State of any such national primary or secondary ambient air quality standard, or (II) interfere with measures required to be included in the applicable implementation plan for any other State under part C to prevent significant deterioration of air quality or to protect visibility, and (ii) insuring compliance with the requirements of section 7426 of this title, relating to interstate pollution abatement'' for ''it contains adequate provisions for intergovernmental cooperation, including measures necessary to insure that emissions of air pollutants from sources located in any air quality control region will not interfere with the attainment or maintenance of such primary or secondary standard in any portion of such region outside of such State or in any other air quality control region''.

Subsec. (a)(2)(F). Pub. L. 95–95, § 108(a)(5), added cl. (vi).

Subsec. (a)(2)(H). Pub. L. 95–190, § 14(a)(1), substituted ''1977;'' for ''1977''.

Pub. L. 95–95, § 108(a)(6), inserted ''except as provided in paragraph (3)(C),'' after ''or (ii)'' and ''or to otherwise comply with any additional requirements established under the Clean Air Act Amendments of 1977'' after ''to achieve the national ambient air quality primary or secondary standard which it implements''.

Subsec. (a)(2)(I). Pub. L. 95–95, § 108(b), added subpar. (I).

Subsec. (a)(2)(J). Pub. L. 95–190, § 14(a)(2), substituted ''; and'' for '', and''.

Pub. L. 95–95, § 108(b), added subpar. (J).

Subsec. (a)(2)(K). Pub. L. 95–95, § 108(b) added subpar. (K).

Subsec. (a)(3)(C). Pub. L. 95–95, § 108(c), added subpar. (C).

Subsec. (a)(3)(D). Pub. L. 95–190, § 14(a)(4), added subpar. (D).

Subsec. (a)(5). Pub. L. 95–95, § 108(e), added par. (5).

Subsec. (a)(5)(D). Pub. L. 95–190, § 14(a)(3), struck out ''preconstruction or premodification'' before ''review''.

Subsec. (a)(6). Pub. L. 95–95, § 108(e), added par. (6).

Subsec. (c)(1). Pub. L. 95–95, § 108(d)(1), (2), substituted ''plan which meets the requirements of this section'' for ''plan for any national ambient air quality primary or secondary standard within the time prescribed'' in subpar. (A) and, in provisions following subpar. (C), directed that any portion of a plan relating to any measure described in first sentence of 7421 of this title (relating to consultation) or the consultation process required under such section 7421 of this title not be required to be promulgated before the date eight months after such date required for submission.

Subsec. (c)(3) to (5). Pub. L. 95–95, § 108(d)(3), added pars. (3) to (5).

Subsec. (d). Pub. L. 95–95, § 108(f), substituted ''and which implements the requirements of this section'' for ''and which implements a national primary or secondary ambient air quality standard in a State''.

Subsec. (f). Pub. L. 95–95, § 107(a), substituted provisions relating to the handling of national or regional energy emergencies for provisions relating to the postponement of compliance by stationary sources or classes of moving sources with any requirement of applicable implementation plans.

Subsec. (g). Pub. L. 95–95, § 108(g), added subsec. (g) relating to publication of comprehensive document.

Pub. L. 95–95, §107(b), added subsec. (g) relating to Governor's authority to issue temporary emergency suspensions.

Subsec. (h). Pub. L. 95–190, §14(a)(5), redesignated subsec. (g), added by Pub. L. 95–95, §108(g), as (h). Former subsec. (h) redesignated (i).

Subsec. (i). Pub. L. 95–190, §14(a)(5), redesignated subsec. (h), added by Pub. L. 95–95, §108(g), as (i). Former subsec. (i) redesignated (j) and amended.

Subsec. (j). Pub. L. 95–190 §14(a)(5), (6), redesignated subsec. (i), added by Pub. L. 95–95, §108(g), as (j) and in subsec. (j) as so redesignated, substituted ''will enable such source'' for ''at such source will enable it''.

1974—Subsec. (a)(3). Pub. L. 93–319, §4(a), designated existing provisions as subpar. (A) and added subpar. (B).

Subsec. (c). Pub. L. 93–319, §4(b), designated existing provisions as par. (1) and existing pars. (1), (2), and (3) as subpars. (A), (B), and (C), respectively, of such redesignated par. (1), and added par. (2).

EFFECTIVE DATE OF 1977 AMENDMENT

Amendment by Pub. L. 95–95 effective Aug. 7, 1977, except as otherwise expressly provided, see section 406(d) of Pub. L. 95–95, set out as a note under section 7401 of this title.

PENDING ACTIONS AND PROCEEDINGS

Suits, actions, and other proceedings lawfully commenced by or against the Administrator or any other officer or employee of the United States in his official capacity or in relation to the discharge of his official duties under act July 14, 1955, the Clean Air Act, as in effect immediately prior to the enactment of Pub. L. 95–95 [Aug. 7, 1977], not to abate by reason of the taking effect of Pub. L. 95–95, see section 406(a) of Pub. L. 95–95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

MODIFICATION OR RESCISSION OF RULES, REGULATIONS, ORDERS, DETERMINATIONS, CONTRACTS, CERTIFICATIONS, AUTHORIZATIONS, DELEGATIONS, AND OTHER ACTIONS

All rules, regulations, orders, determinations, contracts, certifications, authorizations, delegations, or other actions duly issued, made, or taken by or pursuant to act July 14, 1955, the Clean Air Act, as in effect immediately prior to the date of enactment of Pub. L. 95–95 [Aug. 7, 1977] to continue in full force and effect until modified or rescinded in accordance with act July 14, 1955, as amended by Pub. L. 95–95 [this chapter], see section 406(b) of Pub. L. 95–95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

MODIFICATION OR RESCISSION OF IMPLEMENTATION PLANS APPROVED AND IN EFFECT PRIOR TO AUG. 7, 1977

Nothing in the Clean Air Act Amendments of 1977 [Pub. L. 95–95] to affect any requirement of an approved implementation plan under this section or any other provision in effect under this chapter before Aug. 7, 1977, until modified or rescinded in accordance with this chapter as amended by the Clean Air Act Amendments of 1977, see section 406(c) of Pub. L. 95–95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

SAVINGS PROVISION

Section 16 of Pub. L. 91–604 provided that:

''(a)(1) Any implementation plan adopted by any State and submitted to the Secretary of Health, Education, and Welfare, or to the Administrator pursuant to the Clean Air Act [this chapter] prior to enactment of this Act [Dec. 31, 1970] may be approved under section 110 of the Clean Air Act [this section] (as amended by this Act) [Pub. L. 91–604] and shall remain in effect, unless the Administrator determines that such implementation plan, or any portion thereof, is not consistent with applicable requirements of the Clean Air Act [this chapter] (as amended by this Act) and will not provide for the attainment of national primary ambient air quality standards in the time required by such Act. If the Administrator so determines, he shall, within 90 days after promulgation of any national ambient air quality standards pursuant to section 109(a) of the Clean Air Act [section 7409(a) of this title], notify the State and specify in what respects changes are needed to meet the additional requirements of such Act, including requirements to implement national secondary ambient air quality standards. If such changes are not adopted by the State after public hearings and within six months after such notification, the Administrator shall promulgate such changes pursuant to section 110(c) of such Act [subsec. (c) of this section].

''(2) The amendments made by section 4(b) [amending sections 7403 and 7415 of this title] shall not be construed as repealing or modifying the powers of the Administrator with respect to any conference convened under section 108(d) of the Clean Air Act [section 7415 of this title] before the date of enactment of this Act [Dec. 31, 1970].

''(b) Regulations or standards issued under this title II of the Clean Air Act [subchapter II of this chapter] prior to the enactment of this Act [Dec. 31, 1970] shall continue in effect until revised by the Administrator consistent with the purposes of such Act [this chapter].''

FEDERAL ENERGY ADMINISTRATOR

''Federal Energy Administrator'', for purposes of this chapter, to mean Administrator of Federal Energy Administration established by Pub. L. 93–275, May 7, 1974, 88 Stat. 97, which is classified to section 761 et seq. of Title 15, Commerce and Trade, but with the term to mean any officer of the United States designated as such by the President until Federal Energy Administrator takes office and after Federal Energy Administration ceases to exist, see section 798 of Title 15, Commerce and Trade.

Federal Energy Administration terminated and functions vested by law in Administrator thereof transferred to Secretary of Energy (unless otherwise specifically provided) by sections 7151(a) and 7293 of this title.

§ 7411. Standards of performance for new stationary sources

(a) Definitions

For purposes of this section:

(1) The term ''standard of performance'' means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

(2) The term ''new source'' means any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.

(3) The term ''stationary source'' means any building, structure, facility, or installation which emits or may emit any air pollutant. Nothing in subchapter II of this chapter relating to nonroad engines shall be construed to apply to stationary internal combustion engines.

(4) The term ''modification'' means any physical change in, or change in the method of

emption shall (A) promptly notify the Administrator of such exemption and the justification therefor; (B) review the necessity for each such exemption annually; and (C) report to the Administrator annually all such exemptions in effect. Exemptions granted pursuant to this section shall be for a period not to exceed one year. Additional exemptions may be granted for periods not to exceed one year upon the making of a new determination by the head of the Federal agency concerned.

(2) The Administrator may, by rule or regulation, exempt any or all Federal agencies from any or all of the provisions of this Order with respect to any class or classes of contracts, grants, or loans, which (A) involve less than specified dollar amounts, or (B) have a minimal potential impact upon the environment, or (C) involve persons who are not prime contractors or direct recipients of Federal assistance by way of contracts, grants, or loans.

(b) Federal agencies shall reconsider any exemption granted under subsection (a) whenever requested to do so by the Administrator.

(c) The Administrator shall annually notify the President and the Congress of all exemptions granted, or in effect, under this Order during the preceding year.

SEC. 9. *Related Actions*. The imposition of any sanction or penalty under or pursuant to this Order shall not relieve any person of any legal duty to comply with any provisions of the Air Act or the Water Act.

SEC. 10. *Applicability*. This Order shall not apply to contracts, grants, or loans involving the use of facilities located outside the United States.

SEC. 11. *Uniformity*. Rules, regulations, standards, and guidelines issued pursuant to this order and section 508 of the Water Act [33 U.S.C. 1368] shall, to the maximum extent feasible, be uniform with regulations issued pursuant to this order, Executive Order No. 11602 of June 29, 1971 [formerly set out above], and section 306 of the Air Act [this section].

SEC. 12. *Order Superseded*. Executive Order No. 11602 of June 29, 1971, is hereby superseded.

RICHARD NIXON.

§ 7607. Administrative proceedings and judicial review

(a) Administrative subpenas; confidentiality; witnesses

In connection with any determination under section 7410(f) of this title, or for purposes of obtaining information under section 7521(b)(4) [1] or 7545(c)(3) of this title, any investigation, monitoring, reporting requirement, entry, compliance inspection, or administrative enforcement proceeding under the [2] chapter (including but not limited to section 7413, section 7414, section 7420, section 7429, section 7477, section 7524, section 7525, section 7542, section 7603, or section 7606 of this title),,[3] the Administrator may issue subpenas for the attendance and testimony of witnesses and the production of relevant papers, books, and documents, and he may administer oaths. Except for emission data, upon a showing satisfactory to the Administrator by such owner or operator that such papers, books, documents, or information or particular part thereof, if made public, would divulge trade secrets or secret processes of such owner or operator, the Administrator shall consider such record, report, or information or particular portion thereof confidential in accordance with the purposes of section 1905 of title 18, except that such paper, book, document, or information may be disclosed to other officers, employees, or authorized representatives of the United States concerned with carrying out this chapter, to persons carrying out the National Academy of Sciences' study and investigation provided for in section 7521(c) of this title, or when relevant in any proceeding under this chapter. Witnesses summoned shall be paid the same fees and mileage that are paid witnesses in the courts of the United States. In case of contumacy or refusal to obey a subpena served upon any person under this subparagraph,[4] the district court of the United States for any district in which such person is found or resides or transacts business, upon application by the United States and after notice to such person, shall have jurisdiction to issue an order requiring such person to appear and give testimony before the Administrator to appear and produce papers, books, and documents before the Administrator, or both, and any failure to obey such order of the court may be punished by such court as a contempt thereof.

(b) Judicial review

(1) A petition for review of action of the Administrator in promulgating any national primary or secondary ambient air quality standard, any emission standard or requirement under section 7412 of this title, any standard of performance or requirement under section 7411 of this title,,[3] any standard under section 7521 of this title (other than a standard required to be prescribed under section 7521(b)(1) of this title), any determination under section 7521(b)(5) [1] of this title, any control or prohibition under section 7545 of this title, any standard under section 7571 of this title, any rule issued under section 7413, 7419, or under section 7420 of this title, or any other nationally applicable regulations promulgated, or final action taken, by the Administrator under this chapter may be filed only in the United States Court of Appeals for the District of Columbia. A petition for review of the Administrator's action in approving or promulgating any implementation plan under section 7410 of this title or section 7411(d) of this title, any order under section 7411(j) of this title, under section 7412 of this title, under section 7419 of this title, or under section 7420 of this title, or his action under section 1857c–10(c)(2)(A), (B), or (C) of this title (as in effect before August 7, 1977) or under regulations thereunder, or revising regulations for enhanced monitoring and compliance certification programs under section 7414(a)(3) of this title, or any other final action of the Administrator under this chapter (including any denial or disapproval by the Administrator under subchapter I of this chapter) which is locally or regionally applicable may be filed only in the United States Court of Appeals for the appropriate circuit. Notwithstanding the preceding sentence a petition for review of any action referred to in such sentence may be filed only in the United States Court of Appeals for the District of Columbia if such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and pub-

[1] See References in Text note below.

[2] So in original. Probably should be "this".

[3] So in original.

[4] So in original. Probably should be "subsection,".

lishes that such action is based on such a determination. Any petition for review under this subsection shall be filed within sixty days from the date notice of such promulgation, approval, or action appears in the Federal Register, except that if such petition is based solely on grounds arising after such sixtieth day, then any petition for review under this subsection shall be filed within sixty days after such grounds arise. The filing of a petition for reconsideration by the Administrator of any otherwise final rule or action shall not affect the finality of such rule or action for purposes of judicial review nor extend the time within which a petition for judicial review of such rule or action under this section may be filed, and shall not postpone the effectiveness of such rule or action.

(2) Action of the Administrator with respect to which review could have been obtained under paragraph (1) shall not be subject to judicial review in civil or criminal proceedings for enforcement. Where a final decision by the Administrator defers performance of any nondiscretionary statutory action to a later time, any person may challenge the deferral pursuant to paragraph (1).

(c) Additional evidence

In any judicial proceeding in which review is sought of a determination under this chapter required to be made on the record after notice and opportunity for hearing, if any party applies to the court for leave to adduce additional evidence, and shows to the satisfaction of the court that such additional evidence is material and that there were reasonable grounds for the failure to adduce such evidence in the proceeding before the Administrator, the court may order such additional evidence (and evidence in rebuttal thereof) to be taken before the Administrator, in such manner and upon such terms and conditions as to[5] the court may deem proper. The Administrator may modify his findings as to the facts, or make new findings, by reason of the additional evidence so taken and he shall file such modified or new findings, and his recommendation, if any, for the modification or setting aside of his original determination, with the return of such additional evidence.

(d) Rulemaking

(1) This subsection applies to—

(A) the promulgation or revision of any national ambient air quality standard under section 7409 of this title,

(B) the promulgation or revision of an implementation plan by the Administrator under section 7410(c) of this title,

(C) the promulgation or revision of any standard of performance under section 7411 of this title, or emission standard or limitation under section 7412(d) of this title, any standard under section 7412(f) of this title, or any regulation under section 7412(g)(1)(D) and (F) of this title, or any regulation under section 7412(m) or (n) of this title,

(D) the promulgation of any requirement for solid waste combustion under section 7429 of this title,

(E) the promulgation or revision of any regulation pertaining to any fuel or fuel additive under section 7545 of this title,

(F) the promulgation or revision of any aircraft emission standard under section 7571 of this title,

(G) the promulgation or revision of any regulation under subchapter IV–A of this chapter (relating to control of acid deposition),

(H) promulgation or revision of regulations pertaining to primary nonferrous smelter orders under section 7419 of this title (but not including the granting or denying of any such order),

(I) promulgation or revision of regulations under subchapter VI of this chapter (relating to stratosphere and ozone protection),

(J) promulgation or revision of regulations under part C of subchapter I of this chapter (relating to prevention of significant deterioration of air quality and protection of visibility),

(K) promulgation or revision of regulations under section 7521 of this title and test procedures for new motor vehicles or engines under section 7525 of this title, and the revision of a standard under section 7521(a)(3) of this title,

(L) promulgation or revision of regulations for noncompliance penalties under section 7420 of this title,

(M) promulgation or revision of any regulations promulgated under section 7541 of this title (relating to warranties and compliance by vehicles in actual use),

(N) action of the Administrator under section 7426 of this title (relating to interstate pollution abatement),

(O) the promulgation or revision of any regulation pertaining to consumer and commercial products under section 7511b(e) of this title,

(P) the promulgation or revision of any regulation pertaining to field citations under section 7413(d)(3) of this title,

(Q) the promulgation or revision of any regulation pertaining to urban buses or the clean-fuel vehicle, clean-fuel fleet, and clean fuel programs under part C of subchapter II of this chapter,

(R) the promulgation or revision of any regulation pertaining to nonroad engines or nonroad vehicles under section 7547 of this title,

(S) the promulgation or revision of any regulation relating to motor vehicle compliance program fees under section 7552 of this title,

(T) the promulgation or revision of any regulation under subchapter IV–A of this chapter (relating to acid deposition),

(U) the promulgation or revision of any regulation under section 7511b(f) of this title pertaining to marine vessels, and

(V) such other actions as the Administrator may determine.

The provisions of section 553 through 557 and section 706 of title 5 shall not, except as expressly provided in this subsection, apply to actions to which this subsection applies. This subsection shall not apply in the case of any rule or circumstance referred to in subparagraphs (A) or (B) of subsection 553(b) of title 5.

[5] So in original. The word "to" probably should not appear.

(2) Not later than the date of proposal of any action to which this subsection applies, the Administrator shall establish a rulemaking docket for such action (hereinafter in this subsection referred to as a ''rule''). Whenever a rule applies only within a particular State, a second (identical) docket shall be simultaneously established in the appropriate regional office of the Environmental Protection Agency.

(3) In the case of any rule to which this subsection applies, notice of proposed rulemaking shall be published in the Federal Register, as provided under section 553(b) of title 5, shall be accompanied by a statement of its basis and purpose and shall specify the period available for public comment (hereinafter referred to as the ''comment period''). The notice of proposed rulemaking shall also state the docket number, the location or locations of the docket, and the times it will be open to public inspection. The statement of basis and purpose shall include a summary of—

(A) the factual data on which the proposed rule is based;

(B) the methodology used in obtaining the data and in analyzing the data; and

(C) the major legal interpretations and policy considerations underlying the proposed rule.

The statement shall also set forth or summarize and provide a reference to any pertinent findings, recommendations, and comments by the Scientific Review Committee established under section 7409(d) of this title and the National Academy of Sciences, and, if the proposal differs in any important respect from any of these recommendations, an explanation of the reasons for such differences. All data, information, and documents referred to in this paragraph on which the proposed rule relies shall be included in the docket on the date of publication of the proposed rule.

(4)(A) The rulemaking docket required under paragraph (2) shall be open for inspection by the public at reasonable times specified in the notice of proposed rulemaking. Any person may copy documents contained in the docket. The Administrator shall provide copying facilities which may be used at the expense of the person seeking copies, but the Administrator may waive or reduce such expenses in such instances as the public interest requires. Any person may request copies by mail if the person pays the expenses, including personnel costs to do the copying.

(B)(i) Promptly upon receipt by the agency, all written comments and documentary information on the proposed rule received from any person for inclusion in the docket during the comment period shall be placed in the docket. The transcript of public hearings, if any, on the proposed rule shall also be included in the docket promptly upon receipt from the person who transcribed such hearings. All documents which become available after the proposed rule has been published and which the Administrator determines are of central relevance to the rulemaking shall be placed in the docket as soon as possible after their availability.

(ii) The drafts of proposed rules submitted by the Administrator to the Office of Management and Budget for any interagency review process prior to proposal of any such rule, all documents accompanying such drafts, and all written comments thereon by other agencies and all written responses to such written comments by the Administrator shall be placed in the docket no later than the date of proposal of the rule. The drafts of the final rule submitted for such review process prior to promulgation and all such written comments thereon, all documents accompanying such drafts, and written responses thereto shall be placed in the docket no later than the date of promulgation.

(5) In promulgating a rule to which this subsection applies (i) the Administrator shall allow any person to submit written comments, data, or documentary information; (ii) the Administrator shall give interested persons an opportunity for the oral presentation of data, views, or arguments, in addition to an opportunity to make written submissions; (iii) a transcript shall be kept of any oral presentation; and (iv) the Administrator shall keep the record of such proceeding open for thirty days after completion of the proceeding to provide an opportunity for submission of rebuttal and supplementary information.

(6)(A) The promulgated rule shall be accompanied by (i) a statement of basis and purpose like that referred to in paragraph (3) with respect to a proposed rule and (ii) an explanation of the reasons for any major changes in the promulgated rule from the proposed rule.

(B) The promulgated rule shall also be accompanied by a response to each of the significant comments, criticisms, and new data submitted in written or oral presentations during the comment period.

(C) The promulgated rule may not be based (in part or whole) on any information or data which has not been placed in the docket as of the date of such promulgation.

(7)(A) The record for judicial review shall consist exclusively of the material referred to in paragraph (3), clause (i) of paragraph (4)(B), and subparagraphs (A) and (B) of paragraph (6).

(B) Only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. If the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule, the Administrator shall convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed. If the Administrator refuses to convene such a proceeding, such person may seek review of such refusal in the United States court of appeals for the appropriate circuit (as provided in subsection (b) of this section). Such reconsideration shall not postpone the effectiveness of the rule. The effectiveness of the rule may be stayed during such reconsideration, however, by the Administrator or the court for a period not to exceed three months.

(8) The sole forum for challenging procedural determinations made by the Administrator under this subsection shall be in the United States court of appeals for the appropriate circuit (as provided in subsection (b) of this section) at the time of the substantive review of the rule. No interlocutory appeals shall be permitted with respect to such procedural determinations. In reviewing alleged procedural errors, the court may invalidate the rule only if the errors were so serious and related to matters of such central relevance to the rule that there is a substantial likelihood that the rule would have been significantly changed if such errors had not been made.

(9) In the case of review of any action of the Administrator to which this subsection applies, the court may reverse any such action found to be—

(A) arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law;

(B) contrary to constitutional right, power, privilege, or immunity;

(C) in excess of statutory jurisdiction, authority, or limitations, or short of statutory right; or

(D) without observance of procedure required by law, if (i) such failure to observe such procedure is arbitrary or capricious, (ii) the requirement of paragraph (7)(B) has been met, and (iii) the condition of the last sentence of paragraph (8) is met.

(10) Each statutory deadline for promulgation of rules to which this subsection applies which requires promulgation less than six months after date of proposal may be extended to not more than six months after date of proposal by the Administrator upon a determination that such extension is necessary to afford the public, and the agency, adequate opportunity to carry out the purposes of this subsection.

(11) The requirements of this subsection shall take effect with respect to any rule the proposal of which occurs after ninety days after August 7, 1977.

(e) Other methods of judicial review not authorized

Nothing in this chapter shall be construed to authorize judicial review of regulations or orders of the Administrator under this chapter, except as provided in this section.

(f) Costs

In any judicial proceeding under this section, the court may award costs of litigation (including reasonable attorney and expert witness fees) whenever it determines that such award is appropriate.

(g) Stay, injunction, or similar relief in proceedings relating to noncompliance penalties

In any action respecting the promulgation of regulations under section 7420 of this title or the administration or enforcement of section 7420 of this title no court shall grant any stay, injunctive, or similar relief before final judgment by such court in such action.

(h) Public participation

It is the intent of Congress that, consistent with the policy of subchapter II of chapter 5 of title 5, the Administrator in promulgating any regulation under this chapter, including a regulation subject to a deadline, shall ensure a reasonable period for public participation of at least 30 days, except as otherwise expressly provided in section[6] 7407(d), 7502(a), 7511(a) and (b), and 7512(a) and (b) of this title.

(July 14, 1955, ch. 360, title III, § 307, as added Pub. L. 91–604, § 12(a), Dec. 31, 1970, 84 Stat. 1707; amended Pub. L. 92–157, title III, § 302(a), Nov. 18, 1971, 85 Stat. 464; Pub. L. 93–319, § 6(c), June 22, 1974, 88 Stat. 259; Pub. L. 95–95, title III, §§ 303(d), 305(a), (c), (f)–(h), Aug. 7, 1977, 91 Stat. 772, 776, 777; Pub. L. 95–190, § 14(a)(79), (80), Nov. 16, 1977, 91 Stat. 1404; Pub. L. 101–549, title I, §§ 108(p), 110(5), title III, § 302(g), (h), title VII, §§ 702(c), 703, 706, 707(h), 710(b), Nov. 15, 1990, 104 Stat. 2469, 2470, 2574, 2681–2684.)

REFERENCES IN TEXT

Section 7521(b)(4) of this title, referred to in subsec. (a), was repealed by Pub. L. 101–549, title II, § 230(2), Nov. 15, 1990, 104 Stat. 2529.

Section 7521(b)(5) of this title, referred to in subsec. (b)(1), was repealed by Pub. L. 101–549, title II, § 230(3), Nov. 15, 1990, 104 Stat. 2529.

Section 1857c–10(c)(2)(A), (B), or (C) of this title (as in effect before August 7, 1977), referred to in subsec. (b)(1), was in the original ''section 119(c)(2)(A), (B), or (C) (as in effect before the date of enactment of the Clean Air Act Amendments of 1977)'', meaning section 119 of act July 14, 1955, ch. 360, title I, as added June 22, 1974, Pub. L. 93–319, § 3, 88 Stat. 248, (which was classified to section 1857c–10 of this title) as in effect prior to the enactment of Pub. L. 95–95, Aug. 7, 1977, 91 Stat. 691, effective Aug. 7, 1977. Section 112(b)(1) of Pub. L. 95–95 repealed section 119 of act July 14, 1955, ch. 360, title I, as added by Pub. L. 93–319, and provided that all references to such section 119 in any subsequent enactment which supersedes Pub. L. 93–319 shall be construed to refer to section 113(d) of the Clean Air Act and to paragraph (5) thereof in particular which is classified to subsec. (d)(5) of section 7413 of this title. Section 7413(d) of this title was subsequently amended generally by Pub. L. 101–549, title VII, § 701, Nov. 15, 1990, 104 Stat. 2672, and, as so amended, no longer relates to final compliance orders. Section 117(b) of Pub. L. 95–95 added a new section 119 of act July 14, 1955, which is classified to section 7419 of this title.

Part C of subchapter I of this chapter, referred to in subsec. (d)(1)(J), was in the original ''subtitle C of title I'', and was translated as reading ''part C of title I'' to reflect the probable intent of Congress, because title I does not contain subtitles.

CODIFICATION

In subsec. (h), ''subchapter II of chapter 5 of title 5'' was substituted for ''the Administrative Procedures Act'' on authority of Pub. L. 89–554, § 7(b), Sept. 6, 1966, 80 Stat. 631, the first section of which enacted Title 5, Government Organization and Employees.

Section was formerly classified to section 1857h–5 of this title.

PRIOR PROVISIONS

A prior section 307 of act July 14, 1955, was renumbered section 314 by Pub. L. 91–604 and is classified to section 7614 of this title.

Another prior section 307 of act July 14, 1955, ch. 360, title III, formerly § 14, as added Dec. 17, 1963, Pub. L. 88–206, § 1, 77 Stat. 401, was renumbered section 307 by Pub. L. 89–272, renumbered section 310 by Pub. L. 90–148, and renumbered section 317 by Pub. L. 91–604, and is set out as a Short Title note under section 7401 of this title.

[6] So in original. Probably should be ''sections''.

Amendments

1990—Subsec. (a). Pub. L. 101–549, § 703, struck out par. (1) designation at beginning, inserted provisions authorizing issuance of subpoenas and administration of oaths for purposes of investigations, monitoring, reporting requirements, entries, compliance inspections, or administrative enforcement proceedings under this chapter, and struck out "or section 7521(b)(5)" after "section 7410(f)".

Subsec. (b)(1). Pub. L. 101–549, § 706(2), which directed amendment of second sentence by striking "under section 7413(d) of this title" immediately before "under section 7419 of this title", was executed by striking "under section 7413(d) of this title," before "under section 7419 of this title", to reflect the probable intent of Congress.

Pub. L. 101–549, § 706(1), inserted at end: "The filing of a petition for reconsideration by the Administrator of any otherwise final rule or action shall not affect the finality of such rule or action for purposes of judicial review nor extend the time within which a petition for judicial review of such rule or action under this section may be filed, and shall not postpone the effectiveness of such rule or action."

Pub. L. 101–549, § 702(c), inserted "or revising regulations for enhanced monitoring and compliance certification programs under section 7414(a)(3) of this title," before "or any other final action of the Administrator".

Pub. L. 101–549, § 302(g), substituted "section 7412" for "section 7412(c)".

Subsec. (b)(2). Pub. L. 101–549, § 707(h), inserted sentence at end authorizing challenge to deferrals of performance of nondiscretionary statutory actions.

Subsec. (d)(1)(C). Pub. L. 101–549, § 110(5)(A), amended subpar. (C) generally. Prior to amendment, subpar. (C) read as follows: "the promulgation or revision of any standard of performance under section 7411 of this title or emission standard under section 7412 of this title,".

Subsec. (d)(1)(D), (E). Pub. L. 101–549, § 302(h), added subpar. (D) and redesignated former subpar. (D) as (E). Former subpar. (E) redesignated (F).

Subsec. (d)(1)(F). Pub. L. 101–549, § 302(h), redesignated subpar. (E) as (F). Former subpar. (F) redesignated (G).

Pub. L. 101–549, § 110(5)(B), amended subpar. (F) generally. Prior to amendment, subpar. (F) read as follows: "promulgation or revision of regulations pertaining to orders for coal conversion under section 7413(d)(5) of this title (but not including orders granting or denying any such orders),".

Subsec. (d)(1)(G), (H). Pub. L. 101–549, § 302(h), redesignated subpars. (F) and (G) as (G) and (H), respectively. Former subpar. (H) redesignated (I).

Subsec. (d)(1)(I). Pub. L. 101–549, § 710(b), which directed that subpar. (H) be amended by substituting "subchapter VI of this chapter" for "part B of subchapter I of this chapter", was executed by making the substitution in subpar. (I), to reflect the probable intent of Congress and the intervening redesignation of subpar. (H) as (I) by Pub. L. 101–549, § 302(h), see below.

Pub. L. 101–549, § 302(h), redesignated subpar. (H) as (I). Former subpar. (I) redesignated (J).

Subsec. (d)(1)(J) to (M). Pub. L. 101–549, § 302(h), redesignated subpars. (I) to (L) as (J) to (M), respectively. Former subpar. (M) redesignated (N).

Subsec. (d)(1)(N). Pub. L. 101–549, § 302(h), redesignated subpar. (M) as (N). Former subpar. (N) redesignated (O).

Pub. L. 101–549, § 110(5)(C), added subpar. (N) and redesignated former subpar. (N) as (U).

Subsec. (d)(1)(O) to (T). Pub. L. 101–549, § 302(h), redesignated subpars. (N) to (S) as (O) to (T), respectively. Former subpar. (T) redesignated (U).

Pub. L. 101–549, § 110(5)(C), added subpars. (O) to (T).

Subsec. (d)(1)(U). Pub. L. 101–549, § 302(h), redesignated subpar. (T) as (U). Former subpar. (U) redesignated (V).

Pub. L. 101–549, § 110(5)(C), redesignated former subpar. (N) as (U).

Subsec. (d)(1)(V). Pub. L. 101–549, § 302(h), redesignated subpar. (U) as (V).

Subsec. (h). Pub. L. 101–549, § 108(p), added subsec. (h).

1977—Subsec. (b)(1). Pub. L. 95–190 in text relating to filing of petitions for review in the United States Court of Appeals for the District of Columbia inserted provision respecting requirements under sections 7411 and 7412 of this title, and substituted provisions authorizing review of any rule issued under section 7413, 7419, or 7420 of this title, for provisions authorizing review of any rule or order issued under section 7420 of this title, relating to noncompliance penalties, and in text relating to filing of petitions for review in the United States Court of Appeals for the appropriate circuit inserted provision respecting review under section 7411(j), 7412(c), 7413(d), or 7419 of this title, provision authorizing review under section 1857c–10(c)(2)(A), (B), or (C) to the period prior to Aug. 7, 1977, and provisions authorizing review of denials or disapprovals by the Administrator under subchapter I of this chapter.

Pub. L. 95–95, § 305(c), (h), inserted rules or orders issued under section 7420 of this title (relating to noncompliance penalties) and any other nationally applicable regulations promulgated, or final action taken, by the Administrator under this chapter to the enumeration of actions of the Administrator for which a petition for review may be filed only in the United States Court of Appeals for the District of Columbia, added the approval or promulgation by the Administrator of orders under section 7420 of this title, or any other final action of the Administrator under this chapter which is locally or regionally applicable to the enumeration of actions by the Administrator for which a petition for review may be filed only in the United States Court of Appeals for the appropriate circuit, inserted provision that petitions otherwise capable of being filed in the Court of Appeals for the appropriate circuit may be filed only in the Court of Appeals for the District of Columbia if the action is based on a determination of nationwide scope, and increased from 30 days to 60 days the period during which the petition must be filed.

Subsec. (d). Pub. L. 95–95, § 305(a), added subsec. (d).

Subsec. (e). Pub. L. 95–95, § 303(d), added subsec. (e).

Subsec. (f). Pub. L. 95–95, § 305(f), added subsec. (f).

Subsec. (g). Pub. L. 95–95, § 305(g), added subsec. (g).

1974—Subsec. (b)(1). Pub. L. 93–319 inserted reference to the Administrator's action under section 1857c–10(c)(2)(A), (B), or (C) of this title or under regulations thereunder and substituted reference to the filing of a petition within 30 days from the date of promulgation, approval, or action for reference to the filing of a petition within 30 days from the date of promulgation or approval.

1971—Subsec. (a)(1). Pub. L. 92–157 substituted reference to section "7545(c)(3)" for "7545(c)(4)" of this title.

Effective Date of 1977 Amendment

Amendment by Pub. L. 95–95 effective Aug. 7, 1977, except as otherwise expressly provided, see section 406(d) of Pub. L. 95–95, set out as a note under section 7401 of this title.

Termination of Advisory Committees

Advisory committees established after Jan. 5, 1973, to terminate not later than the expiration of the 2-year period beginning on the date of their establishment, unless, in the case of a committee established by the President or an officer of the Federal Government, such committee is renewed by appropriate action prior to the expiration of such 2-year period, or in the case of a committee established by the Congress, its duration is otherwise provided for by law. See section 14 of Pub. L. 92–463, Oct. 6, 1972, 86 Stat. 776, set out in the Appendix to Title 5, Government Organization and Employees.

Pending Actions and Proceedings

Suits, actions, and other proceedings lawfully commenced by or against the Administrator or any other officer or employee of the United States in his official capacity or in relation to the discharge of his official duties under act July 14, 1955, the Clean Air Act, as in effect immediately prior to the enactment of Pub. L. 95–95 [Aug. 7, 1977], not to abate by reason of the taking effect of Pub. L. 95–95, see section 406(a) of Pub. L. 95–95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

MODIFICATION OR RESCISSION OF RULES, REGULATIONS, ORDERS, DETERMINATIONS, CONTRACTS, CERTIFICATIONS, AUTHORIZATIONS, DELEGATIONS, AND OTHER ACTIONS

All rules, regulations, orders, determinations, contracts, certifications, authorizations, delegations, or other actions duly issued, made, or taken by or pursuant to act July 14, 1955, the Clean Air Act, as in effect immediately prior to the date of enactment of Pub. L. 95–95 [Aug. 7, 1977] to continue in full force and effect until modified or rescinded in accordance with act July 14, 1955, as amended by Pub. L. 95–95 [this chapter], see section 406(b) of Pub. L. 95–95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

§ 7608. Mandatory licensing

Whenever the Attorney General determines, upon application of the Administrator—

(1) that—

(A) in the implementation of the requirements of section 7411, 7412, or 7521 of this title, a right under any United States letters patent, which is being used or intended for public or commercial use and not otherwise reasonably available, is necessary to enable any person required to comply with such limitation to so comply, and

(B) there are no reasonable alternative methods to accomplish such purpose, and

(2) that the unavailability of such right may result in a substantial lessening of competition or tendency to create a monopoly in any line of commerce in any section of the country,

the Attorney General may so certify to a district court of the United States, which may issue an order requiring the person who owns such patent to license it on such reasonable terms and conditions as the court, after hearing, may determine. Such certification may be made to the district court for the district in which the person owning the patent resides, does business, or is found.

(July 14, 1955, ch. 360, title III, § 308, as added Pub. L. 91–604, § 12(a), Dec. 31, 1970, 84 Stat. 1708.)

CODIFICATION

Section was formerly classified to section 1857h–6 of this title.

PRIOR PROVISIONS

A prior section 308 of act July 14, 1955, was renumbered section 315 by Pub. L. 91–604 and is classified to section 7615 of this title.

MODIFICATION OR RESCISSION OF RULES, REGULATIONS, ORDERS, DETERMINATIONS, CONTRACTS, CERTIFICATIONS, AUTHORIZATIONS, DELEGATIONS, AND OTHER ACTIONS

All rules, regulations, orders, determinations, contracts, certifications, authorizations, delegations, or other actions duly issued, made, or taken by or pursuant to act July 14, 1955, the Clean Air Act, as in effect immediately prior to the date of enactment of Pub. L. 95–95 [Aug. 7, 1977] to continue in full force and effect until modified or rescinded in accordance with act July 14, 1955, as amended by Pub. L. 95–95 [this chapter], see section 406(b) of Pub. L. 95–95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

§ 7609. Policy review

(a) Environmental impact

The Administrator shall review and comment in writing on the environmental impact of any matter relating to duties and responsibilities granted pursuant to this chapter or other provisions of the authority of the Administrator, contained in any (1) legislation proposed by any Federal department or agency, (2) newly authorized Federal projects for construction and any major Federal agency action (other than a project for construction) to which section 4332(2)(C) of this title applies, and (3) proposed regulations published by any department or agency of the Federal Government. Such written comment shall be made public at the conclusion of any such review.

(b) Unsatisfactory legislation, action, or regulation

In the event the Administrator determines that any such legislation, action, or regulation is unsatisfactory from the standpoint of public health or welfare or environmental quality, he shall publish his determination and the matter shall be referred to the Council on Environmental Quality.

(July 14, 1955, ch. 360, title III, § 309, as added Pub. L. 91–604, § 12(a), Dec. 31, 1970, 84 Stat. 1709.)

CODIFICATION

Section was formerly classified to section 1857h–7 of this title.

PRIOR PROVISIONS

A prior section 309 of act July 14, 1955, ch. 360, title III, formerly § 13, as added Dec. 17, 1963, Pub. L. 88–206, § 1, 77 Stat. 401; renumbered § 306, Oct. 20, 1965, Pub. L. 89–272, title I, § 101(4), 79 Stat. 992; renumbered § 309, Nov. 21, 1967, Pub. L. 90–148, § 2, 81 Stat. 506; renumbered § 316, Dec. 31, 1970, Pub. L. 91–604, § 12(a), 84 Stat. 1705, related to appropriations and was classified to section 1857*l* of this title, prior to repeal by section 306 of Pub. L. 95–95. See section 7626 of this title.

MODIFICATION OR RESCISSION OF RULES, REGULATIONS, ORDERS, DETERMINATIONS, CONTRACTS, CERTIFICATIONS, AUTHORIZATIONS, DELEGATIONS, AND OTHER ACTIONS

All rules, regulations, orders, determinations, contracts, certifications, authorizations, delegations, or other actions duly issued, made, or taken by or pursuant to act July 14, 1955, the Clean Air Act, as in effect immediately prior to the date of enactment of Pub. L. 95–95 [Aug. 7, 1977] to continue in full force and effect until modified or rescinded in accordance with act July 14, 1955, as amended by Pub. L. 95–95 [this chapter], see section 406(b) of Pub. L. 95–95, set out as an Effective Date of 1977 Amendment note under section 7401 of this title.

§ 7610. Other authority

(a) Authority and responsibilities under other laws not affected

Except as provided in subsection (b) of this section, this chapter shall not be construed as

No. _____

In the Supreme Court of the United States

OHIO, ET AL.
Applicants
v.

ENVIRONMENTAL PROTECTION AGENCY, ET AL.
Respondents.

ON APPLICATION FOR STAY OF ADMINISTRATIVE ACTION TO THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

STATE APPLICANTS' EMERGENCY APPLICATION FOR A STAY OF ADMINISTRATIVE ACTION

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The petitioners below included Ohio, Indiana, and West Virginia. This application refers to these States collectively as "the state applicants."

Other petitioners below included: Case No. 23-1157: State of Utah; Case No. 23-1181: Kinder Morgan, Inc.; Case No. 23-1190: American Forest & Paper Association; Case No. 23-1191: Midwest Ozone Group; Case No. 23-1193: Interstate Natural Gas Association of America and American Petroleum Institute; Case No. 23-1195: Associated Electric Cooperative, Inc., Deseret Generation & Transmission Co-Operative, d/b/a Deseret Power Electric Cooperative, Ohio Valley Electric Corporation, Wabash Valley Power Association, Inc., d/b/a Wabash Valley Power Alliance, America's Power, National Rural Electric Cooperative Association, and Portland Cement Association; Case No. 23-1199: National Mining Association; Case No. 23-1200: American Iron and Steel Institute; Case No. 23-1201: State of Wisconsin; Case No. 23-1202: Enbridge (U.S.) Inc.; Case No. 23-1203: American Chemistry Council and American Fuel & Petrochemical Manufacturers; Case No. 23-1205: TransCanada Pipeline USA Ltd.; Case No. 23-1206: Hybar LLC; Case No. 23-1207: United States Steel Corporation; Case No. 23-1208: Union Electric Company, d/b/a Ameren Missouri; Case No. 23-1209: State of Nevada; Case No. 23-1211: Arkansas League of Good Neighbors.

The respondents are Environmental Protection Agency and Michael S. Regan, Administrator, U.S. EPA.

TO THE HONORABLE JOHN G. ROBERTS, JR., CHIEF JUSTICE OF THE SUPREME COURT OF THE UNITED STATES AND CIRCUIT JUSTICE FOR THE DISTRICT OF COLUMBIA CIRCUIT:

The Clean Air Act pictures a world where the States and the EPA share responsibility for ensuring the nation's air quality. Relevant here, the Act allows each State to develop a plan to prevent emissions within its borders from significantly affecting other States' air quality. The EPA then reviews each State's plan. But that review is deferential: if a State's plan meets statutory requirements, the EPA "shall approve" it, regardless of whether the EPA has a better idea for how to accomplish the Act's goals. 42 U.S.C. §7410(k)(3). Correspondingly, the EPA has power to impose a federal plan *only if* a State fails to submit a statutorily compliant plan. *See* §7410(c)(1).

The EPA views its role much differently. In early 2022, it announced a plan to reject the air-quality plans of roughly half of the country's States. At nearly the same time, the EPA revealed its own federal plan, which relied on a coordinated, nationwide approach to emissions reductions. Despite many objections, the EPA finalized that plan in June. *Federal 'Good Neighbor Plan' for the 2015 Ozone National Ambient Air Quality*, 88 Fed. Reg. 36654 (June 5, 2023). This federal plan purports to establish emission-reduction standards for "23 upwind states." *Id.* at 36656. But due to a combination of litigation and interim rulemaking, a dozen of those States and over three quarters of the emissions that the plan sought to regulate, are already exempt from the plan. Nonetheless, the EPA insists that its federal plan should still apply in the remaining States.

The Court should stay application of this federal plan while many parties—including Ohio, Indiana, and West Virginia—challenge the plan in the D.C. Circuit. The challengers are likely to succeed on their claims under the Administrative Procedure Act. That Act requires federal agencies to reach decisions in a considered matter, so as to avoid arbitrary and capricious government action. 5 U.S.C. §706(2)(A). In promulgating the federal plan, the EPA did not meet that threshold. Tellingly, in just a few months, the federal plan is down to a sliver of what the EPA intended. And the federal plan's failures were both foreseeable and inevitable. Most glaringly, the EPA's rulemaking ignored obvious problems with its attempt to twist the Clean Air Act into a system of top-down regulation instead of the system of cooperative federalism that Congress intended.

The remaining stay factors also favor pausing the federal plan. The plan inflicts irreparable, economic injuries on the States and others every day it remains in effect. Worse still, the plan is likely to cause electric-grid emergencies, as power suppliers strain to adjust to the federal plan's terms. To prevent these harms, the Court should step in now.

JURISDICTION

This Court has jurisdiction to resolve this application under 28 U.S.C. §§1331 and 2101(f).

STATEMENT

1. In our federalist system, counteracting air pollution is supposed to be a cooperative effort. "Air pollution is transient, heedless of state boundaries." *EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489, 496 (2014). Notwithstanding that transience, "States and local governments" have traditionally shouldered the "primary responsibility" for controlling air pollution. *See* 42 U.S.C. §7401(a)(3). Against this backdrop, Congress passed the Clean Air Act "to encourage and assist the development and operation of regional air pollution prevention and control programs." §7401(b)(4). The Act is "an experiment in cooperative federalism" *Michigan v. EPA*, 268 F.3d 1075, 1083 (D.C. Cir. 2001). On the one hand, the Act tasks the EPA with establishing National Ambient Air Quality Standards for certain air pollutants. *Homer*, 572 U.S. at 498. (In this acronym-heavy field, regulators and stakeholders often refer to these standards as "NAAQS." The state applicants simply call them "air-quality standards.") On the other hand, the *States* retain "the primary responsibility for assuring air quality" within their borders, including the power to choose the "manner in which" they will satisfy the Act's demands. §7407(a).

States meet their obligations under the Act by crafting "state-implementation plans," often called "SIPs" in the field. These state plans implement air-quality standards by incorporating measures adequate to assure "compliance with the Act's requirements." *Homer*, 572 U.S. at 507. Among other things, a state plan must show that the State will comply with the Act's "good neighbor" provision, which requires "upwind States to reduce emissions to account for pollution exported beyond their borders." *Id.* at 499; *accord* §7410(a)(2)(D). To account for a State's good-neighbor obligations, a state plan must "contain adequate provisions" to prohibit in-state emissions from "contribut[ing] significantly to nonattainment in, or interfer[ing] with maintenance by, any other State" in its own compliance with air-quality standards.

§7410(a)(2)(D)(i)(I). But as "long as the ultimate effect of a State's choice of emission limitations is compliance with" national air-quality standards, "the State is at liberty to adopt whatever mix of emission limitations it deems best suited to its particular situation." *Train v. Natural Res. Def. Council*, 421 U.S. 60, 79 (1975).

The EPA, for its part, serves a "ministerial" role when reviewing state-implementation plans. *Texas v. EPA*, 829 F.3d 405, 411 (5th Cir. 2016) (quotations omitted). If a state plan meets the Act's requirements, the EPA "shall approve" it. §7410(k)(3). As a result, the EPA cannot disapprove a state plan merely because it believes there is a better way to achieve the Act's requirements. The Clean Air Act thus leaves "[e]ach State … wide discretion in formulating its plan." *Union Electric Co. v. EPA*, 427 U.S. 246, 250 (1976); *see also Train*, 421 U.S. at 79.

The EPA shall issue a "federal implementation plan" for a State to follow—sometimes called a "FIP"—*only if* the State's plan "does not satisfy the [Act's] minimum criteria." §7410(c)(1)(A). Federal plans, like state plans, must meet the Act's requirements. *See* §§7410(c)(1), 7602(y). Although the EPA has authority to promulgate a federal-implementation plan "at any time" after it disapproves of a State's plan, §7410(c)(1), the Act expects continued cooperation between the EPA and the State. For instance, if the EPA finds state plan inadequate, the Act anticipates that the EPA will provide an opportunity for "the State" to "correct[] the deficiency." §7410(c)(1)(B). To facilitate this back and forth with the States, the Act gives the EPA a two-year cushion between (1) the date it "disapproves a State implementation plan submission in whole or in part" and (2) the date it needs to issue a federal-implementation plan. §7410(c)(1)(B). Consistent with that cushion, a State may submit a revised state plan any time in the two-year period before any federal plan would go into effect. *See* §7410(c)(1). All this fits with the Act's foundational principle that the *States* retain the "primary responsibility for assuring air quality." §7407(a). Congress viewed federal plans as a last resort.

2. In October 2015, the EPA revised air-quality standards for ozone pollution. *National Ambient Air Quality Standard for Ozone*, 80 Fed. Reg. 65292, 65301 (Oct. 26, 2015). That change triggered the States' obligation to update their state-implementation plans. §7410(a)(1). Relevant here, the updated state plans needed to include plans for how each State would satisfy the Act's "good neighbor" provision. §7410(a)(2)(D).

For a while, the process remained cooperative. In 2018, the EPA issued guidance to "assist states in developing" state-implementation plans for the new standards. *See Memorandum from Peter Tsirigotis* at 3 (Mar. 27, 2018), https://perma.cc/Y8YF-CQMB ("March Memorandum"); *see also Memorandum from Peter Tsirigotis* (Aug. 31, 2018), https://perma.cc/G8EN-RN8Q ("August Memorandum"); *see also Texas v. EPA*, No. 23-60069, 2023 U.S. App. LEXIS 13898, *6–7 & n.2 (5th Cir. May 1, 2023) (*per curiam*). The EPA included modeling parameters that the States could use in developing their plans, along with explanations of the appropriate threshold for determining whether emissions contributions are significant. *See* March Memorandum at Attachments B & C; August Memorandum 4. Further, the EPA "recommend[ed] that states reach out to EPA Regional offices and work together to accomplish the goal of developing, submitting, and reviewing approvable" state plans. March Memorandum 6. Many States—including state applicants—accepted this offer and worked closely with the EPA to formulate compliant state plans. *See* App.C-6 (Crowder Decl. ¶¶14–15).

The States then submitted their state-implementation plans according to the EPA's advice. Ohio submitted its state plan in September 2018, Indiana in November of the same year, and West Virginia in February 2019. *See Air Plan Disapproval; Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin*, 87 Fed. Reg. 9838, 9845, 9849 (Feb. 22, 2022); *Air Plan Disapproval; West Virginia*, 87 Fed. Reg. 9516, 9522 (Feb. 22, 2022). Under the Act, the EPA had eighteen months to approve or disapprove of the proposed state plans. *See* §§7410(k)(1)(B), (k)(2). But it sat on the States' submissions for much longer. And for all that time, the EPA never hinted at a problem with the state plans.

Things suddenly changed in February 2022. On a single day, the EPA proposed to disapprove the submissions of nineteen different States. *See, e.g.*, 87 Fed. Reg. at 9852 (Ohio and Indiana); 87 Fed. Reg. at 9516 (West Virginia); *Air Plan Disapproval; Alabama, Mississippi, Tennessee*, 87 Fed. Reg. 9545 (Feb. 22, 2022); *Air Plan Disapproval; Arkansas, Louisiana, Oklahoma, Texas*, 87 Fed. Reg. 9798 (Feb. 22, 2022); *Air Plan Disapproval; Kentucky*, 87 Fed. Reg. 9498 (Feb. 22, 2022); *Air Plan Disapproval; Maryland*, 87 Fed. Reg. 9463 (Feb. 22, 2022); *Air Plan Disapproval; Missouri*, 87 Fed. Reg. 9533 (Feb. 22, 2022); *Air Plan Disapproval; New York and New Jersey*, 87 Fed. Reg. 9484 (Feb. 22, 2022). A few months later, the EPA disapproved four more States' plans, bringing the total number of disapproved state plans to twenty-three. *See Air Plan Disapprovals*, 88 Fed. Reg. 9336, 9337 n.6 (Feb. 13, 2023).

At that point, the EPA might have worked with the States to correct the perceived deficiencies in the state plans. *See* §7410(c)(1)(B). The EPA, however, chose a different course. Less than two months after proposing to disapprove the plans of nineteen States, and before the deadline for commenting on the disapprovals even expired, the EPA proposed its own federal-implementation plan. *Federal Implementation Plan Addressing Regional Ozone Transport*, 87 Fed. Reg. 20036 (Apr. 6, 2022). The proposed federal plan sought to "resolve" the good-neighbor obligations for roughly half of this country's States. *Id.* at 20038. More precisely, the EPA imposed a single, coordinated plan to reduce air pollution from 23 States based on a combined analysis of those States' upwind contributions to ozone pollution in downwind States. *Id*. Under this multi-state approach, the EPA purported to apportion the responsibility of reducing emissions "collectively" among "contributing upwind states." *Id.* at 20076. The EPA said that this coordinated approach would yield an "'efficient and equitable solution'" by imposing "uniform cost[s]" on "states that are collectively responsible for air quality." *Id.* (quoting *Homer*, 572 U.S. at 519); *see also id.* at 20060.

3. Over vehement protests, the EPA pushed on with its plan to control the nation's air quality. This past February, it finalized disapprovals for the state-implementation plans of over twenty States, including Ohio, Indiana, and West Virginia. 88 Fed. Reg. at 9336. Many States filed petitions in the courts of appeals challenging the EPA's disapprovals. *See, e.g.*, *West Virginia v. EPA*, No. 23-1418 (4th Cir.); *Texas v. EPA*, No. 23-60069 (5th Cir.); *Kentucky v. EPA*, No. 23-3216 (6th Cir.); *Arkansas v. EPA*, No. 23-1320 (8th Cir.); *Utah v. EPA*, No. 23-9509 (10th Cir.); *see also* §7607(b)(1). Other States—including Ohio and Indiana—chose not to pursue litigation, hoping to work with the EPA to come up with a solution acceptable to all sides. *See* §7410(c)(1).

Litigation quickly highlighted the serious flaws in the EPA's mass disapproval of state-implementation plans. One court, for example, concluded that rather than performing a ministerial review of state plans under the Clean Air Act, *see above* 4, the EPA "exceeded its authority" by utilizing "non-statutory factors" during its evaluation. *Texas*, 2023 U.S. App. LEXIS 13898 at *16–18. That "approach invert[ed]" the Clean Air Act by denying the States their "primary" role in the regulation of air pollution. *Id.* at *19–20 (quotations omitted). Another problem was that the EPA analyzed state plans using modeling data that was not available when the States made their submissions. *Id.* at *24–25; *Kentucky v. EPA*, Nos. 23-3216/3225, 2023 U.S. App. LEXIS 18981, *10–11 (6th Cir. July 25, 2023). That choice unlawfully moved the "goalpost" on the States. *Texas*, 2023 U.S. App. LEXIS 13898 at *25. Yet another problem was that the EPA's review relied on "a material shift" from the earlier guidance it had offered to the States about how to meet their requirements. *Id.* at 23. And many States had used the EPA's earlier guidance, to their detriment, when crafting their state plans. *See id.* at *26; 87 Fed. Reg. at 9840–41.

As proves important later on, the EPA had not yet finalized its federal-implementation plan when the just-discussed litigation commenced. And as part of the comment process for the federal plan, commenters previewed the many legal problems with the EPA's disapprovals of state plans. *See* 88 Fed. Reg. at 36672; EPA, *Response to Public Comments* at 2–6, 9–11, 145–55, https://perma.cc/N7CK-3YTE. Those commenters proved prescient: before the EPA finalized the federal plan, the Fifth Circuit held that the EPA likely behaved unlawfully when it disapproved the state plans. *Texas*, 2023 U.S. App. LEXIS 13898 at *16. A panel of that court thus stayed the EPA's regulatory actions as to Texas and Louisiana. *Id.* at *31. The Sixth and Eighth Circuits also stayed the EPA's state-plan disapprovals pending judicial review. *See, e.g.*, *Kentucky*, 2023 U.S. App. LEXIS 13442 at *2; Order, *Arkansas v. EPA*, No. 23-1320 (8th Cir. May 25, 2023); Order, *Missouri v. EPA*, No. 23-1719 (8th Cir. May 26, 2023). Because only an operative state-plan denial can trigger the EPA's obligation to impose a federal one, *see* §7410(c)(1), the EPA necessarily lost its authority to impose a federal plan as to those States.

4. The EPA pressed on anyway, finalizing its federal-implementation plan in early June. 88 Fed. Reg. 36654. Notwithstanding litigation that threatened to disrupt the federal plan's multi-state approach, and courts staying the EPA's actions in several critical States, the EPA stuck with its nationwide plan. That is, the federal plan tries to resolve the good-neighbor obligations of "23 upwind states"—including Ohio, Indiana, and West Virginia—even though the EPA could not enforce it against many of those same States from the outset. *Id.* at 36656; *see, e.g.*, *Texas*, 2023 U.S. App. LEXIS 13898.

The federal plan requires emissions reductions for each State that are based, in large part, on the "combined effect of the entire program across all linked upwind states." 88 Fed. Reg. at 36749. According to the EPA, the federal plan ensures "national consistency" by imposing "a uniform framework of policy judgments" across the country. *Id.* at 36673. And the EPA explained that a consistent rule across "all jurisdictions" was "vital" to ensuring that the burdens of regulation were divided efficiently and equitably among the States. *Id.* at 36691–92; *see also id.* at 36676–77, 36719, 36741. The final rule, the EPA concluded, is a "nationally applicable" action within the meaning of the Clean Air Act, "given the interdependent nature of interstate pollution transport" and the "large number of states" to which the federal plan applied. *Id.* at 36860. Pursuant to executive order, the EPA also assessed the federalism implications of its rulemaking. Surprisingly, the EPA claimed that its plan did "not have federalism implications" and would not "have substantial direct effects on the states." *Id.* at 36858.

The finalized federal plan is ambitious. It imposes specific emissions reductions on several new industrial stationary sources (referred to as "non-Electric Generating Units" or "non-EGUs") for the first time in decades with respect to the Act's good-neighbor provision. *See id.* at 36654, 36681. It also permits power plants within the States to participate in an overhauled cap-and-trade program, but imposes "enhancements" that reduce flexibility and create costly compliance challenges. *See* *id.* at 36762–70. Specifically, the federal plan shrinks the tradeable allowance bank by removing "surplus … allowances" that "diminish[] the intended stringency" of the program. *Id.* at 36767. Future allowances will be so hard to come by that sources may be forced to choose between steep penalties, changing their operations, or shutting down.

Ostensibly, the EPA left open the possibility that a State could "replace" the federal plan with its own plan. *Id.* at 36838. But that is, in any real sense, impossible under the EPA's own logic. The EPA, for example, warned that the agency "does not anticipate revisiting its" regulatory framework and that any state plan will have to be "equivalent to" the federal plan. *Id.* at 36839. That is, the EPA "anticipate[s] that states seeking to replace the" federal plan with a state plan "that takes an alternative approach" will "need to establish, at a minimum, an equivalent level of emissions reduction to what the [federal plan] requires." *Id.* The EPA further said that "[t]he most straightforward method for a state to submit a presumptively approvable" state plan is to provide a plan that looks much like the federal plan. *See id.* at 36842.

5. After finalizing the federal plan, the EPA continued to receive bad news in courts around the country. The Sixth, Ninth, and Tenth Circuits joined the Fifth in concluding that the States had a strong case that the EPA's state-plan disapprovals were illegal. *Kentucky*, 2023 U.S. App. LEXIS 18981 at *10–11; Order at 2, *Nevada Cement Co. v. EPA*, No. 23–682 (9th Cir. July 3, 2023); Order at 4, *Utah v. EPA*, No. 23-9509 (10th Cir. July 27, 2023). The Fourth and Eleventh Circuits also stayed the EPA's actions, without analysis, to allow for judicial review of challenges to state-plan disapprovals. *See* Order, *West Virginia v. EPA*, No. 23–1418 (4th Cir. Aug. 10, 2023); *Alabama v. EPA*, No. 23-11173 (11th Cir. Aug. 17, 2023). At this point, *every circuit* to have considered staying a state-plan disapproval—seven in total—has granted a stay.

Eventually, the EPA acknowledged the broad implications of this nationwide litigation for its federal-implementation plan. In late July, the EPA issued an interim final rule reacting to litigation over state-plan disapprovals. *Response to Judicial Stays of SIP Disapproval Action for Certain States*, 88 Fed. Reg. 49295 (July 31, 2023). The interim rule stayed the federal plan's application to Arkansas, Kentucky, Louisiana, Mississippi, Missouri, and Texas. *Id.* at 49295.

A few weeks ago, the EPA issued another interim final rule responding to the next wave of judicial orders halting its state-plan disapprovals. *Response to Additional Judicial Stays of SIP Disapproval Action for Certain States*, 88 Fed. Reg. 67102 (Sept. 29, 2023). In this second interim rule, the EPA expanded its stay of the federal plan to six additional states: Alabama, Minnesota, Nevada, Oklahoma, Utah, and West Virginia. *Id.* at 67102. For West Virginia, however, the stay may be lifted in a matter of weeks. The length of the Fourth Circuit's stay is tied to an oral argument, scheduled for October 27, in litigation pertaining to West Virginia's state-plan disapproval. *See id.* at 67103. Notably, during its interim rulemaking the EPA again concluded without explanation that its actions would have no federalism implications. 88 Fed. Reg. at 49301; 88 Fed. Reg. at 67105.

At this point, the federal plan—a plan designed to apply collectively to the "interdependent" emissions from "23 upwind states," *see* 88 Fed. Reg. at 36656, 36860—applies to only 11 States. That means, in comparison to the federal plan's stated intent, it now regulates only 11% of the emissions from electric-generating units and about 40% of the emissions from industrial sources. *See* EPA, *Good Neighbor Plan for 2015 Ozone NAAQS* (last updated June 30, 2023), *computed from data maps available at* https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs. All in all, *over 75%* of the emissions that the federal plan originally set out to control are presently exempt from the federal plan. *See id.*

6. The federal-implementation plan became effective on August 4, 2023. 88 Fed. Reg. at 36654. Before that effective date, Ohio, Indiana, and West Virginia filed a petition in the D.C. Circuit challenging the federal plan. Several other petitioners, representing various other States and various private industries, also challenged the federal plan. Shortly after filing their petitions, the States and private petitioners moved to stay the federal plan pending judicial review. The States argued, among other things, that the EPA's rulemaking process circumvented the Clean Air Act's cooperative-federalism mandate by forcing its own top-down control over state-level air-pollution reduction.

In late September, a divided panel of the D.C. Circuit Court of Appeals denied the motions to stay without analysis. App.A-1–2. One judge—Judge Walker—dissented stating that he would have granted the stay. App.A-1.

7. The States now bring this application for a stay.

REASONS TO GRANT THE APPLICATION

In deciding whether to issue a stay, this Court considers "four factors: '(1) whether the stay applicant has made a strong showing that he is likely to succeed on the merits; (2) whether the applicant will be irreparably injured absent a stay; (3) whether issuance of the stay will substantially injure the other parties interested in the proceeding; and (4) where the public interest lies.'" *Nken v. Holder*, 556 U.S. 418, 434 (2009) (quoting *Hilton v. Braunskill*, 481 U.S. 770, 776 (1987)). The first two factors "are the most critical." *Id.*

Here, each factor favors a stay. Although the States retain "the primary responsibility for assuring air quality," 42 U.S.C. §7407(a), the EPA persists in unlawfully imposing its vision of air-quality regulation. After disapproving the state-implementation plans of nearly half the States in the Union, the EPA finalized a *single* federal-implementation plan for all of them. *Federal 'Good Neighbor Plan' for the 2015 Ozone National Ambient Air Quality*, 88 Fed. Reg. 36654 (June 5, 2023). The EPA purported to set emission-reduction standards through a coordinated plan designed to reduce the collective emissions of "23 upwind States" under the Clean Air Act's good-neighbor provision. *Id.* at 36656, 36860. Yet, after just a few months, the federal plan is already a disaster. The plan now applies to only 11 of the 23 States it was supposed to cover. And it reaches less than 25% of the emissions it set out to regulate. But rather than admitting failure and returning to the drawing board, the EPA has doubled down on its "dictatorial" quest for top-down control on reducing air pollution. *Texas v. EPA*, No. 23-60069, 2023 U.S. App. LEXIS 13898, *28 (5th Cir. May 1, 2023).

Because this case presents important issues, because the States will likely prevail on the merits, and because the States will suffer in the meantime, the Court should step in now to stay the federal plan pending judicial review.

I. The States will likely prevail on the merits.

A. The Administrative Procedure Act requires federal courts to set aside agency action that is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 5 U.S.C. §706(2)(A). Applying this text, "administrative agencies are required to engage in reasoned decisionmaking." *Michigan v. EPA*, 576 U.S. 743, 750 (2015) (quotations omitted). "Not only must an agency's decreed result be within the scope of its lawful authority, but the process by which it reaches that result must be logical and rational." *Id.* (quotations omitted). This means that "agency action is lawful only if it rests on a consideration of the relevant factors." *Id.* (quotations omitted). And an agency must "display awareness" of the surrounding context in which it operates and "provide reasoned explanation for its action." *FCC v. Fox TV Stations, Inc.*, 556 U.S. 502, 515 (2009). Along the same lines, "an agency may not entirely fail to consider an important aspect of the problem when deciding whether regulation is appropriate." *Michigan*, 576 U.S. at 752 (alterations accepted, quotations omitted).

It follows from these principles that an agency has an "obligation to acknowledge and account for" the "regulatory posture the agency creates." *Portland Cement Ass'n v. EPA*, 665 F.3d 177, 187 (D.C. Cir. 2011) (*per curiam*); *accord Zen Magnets, LLC v. Consumer Prod. Safety Comm'n*, 841 F.3d 1141, 1150 (10th Cir. 2016). Said another way, an agency cannot ignore the effects—or likely effects—of "contemporaneous and closely related rulemaking." *Portland Cement Ass'n*, 665 F.3d at 187; *see also Office of Commc'n of United Church of Christ v. FCC*, 707 F.2d 1413, 1441–42 (D.C. Cir. 1983). An agency must instead offer a "satisfactory explanation," which takes a "hard look" at any "salient problems" arising from the regulatory landscape. *Portland Cement Ass'n*, 665 F.3d at 187 (quotations omitted). To be sure, an agency "must promulgate rules based on the information it currently possesses." *Id.* But that does not give an agency license to ignore "obvious" trends, *see Zen Magnets, LLC*, 841 F.3d at 1150, particularly when those trends are a product of the agency's "own process," *see Portland Cement Ass'n*, 665 F.3d at 187.

B. Turning to this case, the federal plan is already a failed experiment. It applies to less than half of the States, and under a quarter of the emissions, that it set out to regulate. In reality, the federal plan was always doomed; the EPA's carefully timed gambit to work around the Clean Air Act's structure of cooperative federalism was never going to work. With any reasoned consideration, the EPA would have known as much. Indeed, *every circuit* to have considered a state-plan disapproval—seven in total—has stayed the EPA's action. And some did so before the federal plan was even finalized. All told, the EPA failed "to acknowledge and account for" the surrounding regulatory landscape. *See Portland Cement Ass'n*, 665 F.3d at 187. As a result, the state applicants are likely to succeed on the merits.

Begin with where we are now. Since promulgating its federal-implementation plan (just a few months ago), the EPA has issued two interim rules that exempt a dozen States from the plan. *Response to Judicial Stays of SIP Disapproval Action for*

Certain States, 88 Fed. Reg. 49295 (July 31, 2023); *Response to Additional Judicial Stays of SIP Disapproval Action for Certain States*, 88 Fed. Reg. 67102 (Sept. 29, 2023). These exemptions block the federal plan from achieving its purpose. As the EPA suggests, upwind States' contribution to pollution in downwind States will "substantial[ly] decrease" when upwind states "collectively" participate in the emissions-reduction program. *See id.* at 36683. The data bears this out. After exempting a dozen States, the federal plan regulates only (1) about 11% of the emissions from electric-generating units it intended to regulate and (2) about 40% of emissions from industrial sources it intended to regulate. *See* EPA, *Good Neighbor Plan for 2015 Ozone NAAQS* (last updated June 30, 2023)*, computed from data maps available at* https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs. Overall, more than 75% of the emissions that the federal plan set out to control are now exempt from the federal plan. *See id.* The federal plan is but a shell of its original self.

This result was entirely foreseeable. It stems from the EPA's refusal to engage with the cooperative federalism the Clean Air Act requires. Recall that the Act establishes a system under which the States retain the "primary responsibility for assuring air quality." 42 U.S.C. §7407(a). As Congress wrote it, the EPA plays a secondary, "ministerial" role when reviewing state-implementation plans. *Texas v. EPA*, 829 F.3d 405, 411 (5th Cir. 2016) (quotations omitted). But here, the EPA has cast itself in the leading role. In February 2022, the EPA launched a coordinated attack on the state plans of nearly twenty States. *See Air Plan Disapproval; Alabama, Mississippi, Tennessee*, 87 Fed. Reg. 9545 (Feb. 22, 2022); *Air Plan Disapproval;*

Arkansas, Louisiana, Oklahoma, Texas, 87 Fed. Reg. 9798 (Feb. 22, 2022); *Air Plan Disapproval; Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin***,** 87 Fed. Reg. 9838 (Feb. 22, 2022); *Air Plan Disapproval; Kentucky*, 87 Fed. Reg. 9498 (Feb. 22, 2022); *Air Plan Disapproval; Maryland*, 87 Fed. Reg. 9463 (Feb. 22, 2022); *Air Plan Disapproval; Missouri*, 87 Fed. Reg. 9533 (Feb. 22, 2022); *Air Plan Disapproval; New York and New Jersey*, 87 Fed. Reg. 9484 (Feb. 22, 2022); *Air Plan Disapproval; West Virginia*, 87 Fed. Reg. 9516 (Feb. 22, 2022). As it just so happened, the EPA had a single federal plan ready to go for all of these States in less than two months. *Federal Implementation Plan Addressing Regional Ozone Transport*, 87 Fed. Reg. 20036 (Apr. 6, 2022). And the EPA's finalized federal plan drives home the agency's mindset. It appears that in the EPA's view, the only acceptable state plan is one that is functionally equivalent to its own. *See* 88 Fed. Reg. at 36839.

Unsurprisingly, the EPA's thinly veiled attempt to transform the Clean Air Act into a top-down system of regulation led to problems in the EPA's decisionmaking process. Two related features of the federal-implementation plan contribute to the problems. *First*, the EPA's authority to issue a federal-implementation plan kicks in only if the agency properly disapproves a state-implementation plan. *See* 42 U.S.C. §7410(c)(1). Thus, the EPA had authority to issue a nationwide federal-implementation plan only if the EPA properly disapproved the state plan of every covered State. *Second*, the federal plan at issue here relied on a multi-state analysis to reach an "efficient and equitable solution" for how to "apportion emissions reduction responsibilities among upwind states that are collectively responsible for downwind air quality." 88 Fed. Reg. at 36719 (quotations omitted). In other words, the EPA's multi-state analysis was based on the participation of all "23 upwind states" that would be subject to the federal plan. *See id.* at 36667. Thus, as the EPA has since admitted in litigation, its plan "depends on the continuing operation of 'interdependent' interstate mechanisms, like the allowance trading program, that reach beyond state or regional borders." EPA Motion to Dismiss or Transfer at 16, *Oklahoma v. EPA*, 23-9561 (10th Cir. July 20, 2023); *see also* 88 Fed. Reg. at 36691 (explaining that "consistency" across "all jurisdictions is vital").

Putting all of this together, the EPA failed to consider a relevant factor during its decisionmaking: namely, the numerous and obvious flaws in its decisions to disapprove state-implementation plans. For one thing, the EPA began by disapproving state plans *en masse*. And it used non-statutory factors to deny those plans, relied on data unavailable to the States at the time of their submissions, and contradicted its own earlier guidance. *See Texas*, 2023 U.S. App. LEXIS 13898 at *16–28. Importantly, the EPA was well *aware* of these flaws when it was finalizing its federal plan. Many States had immediately gone to court upon disapproval of their plans. *See above* 7–8. And commenters had pointed out the many legal issues with the EPA's disapproval. *See* EPA, Response to Public Comments at 2–6, 9–11, 145–55, https://perma.cc/N7CK-3YTE. The Fifth Circuit had too. Recall that it granted a stay, and held the EPA's actions likely unlawful, *before* the EPA finalized the federal plan. *Texas v. EPA*, No. 23-60069, 2023 U.S. App. LEXIS 13898 at *16–28. And other circuits had also begun to stay the EPA's actions by late spring, before the federal plan was finalized. *See Kentucky v. EPA*, Nos. 23-3216/3225, 2023 U.S. App. LEXIS 13442 (6th Cir. May 31, 2023); Order, *Arkansas v. EPA*, No. 23-1320 (8th Cir. May 25, 2023); Order, *Missouri v. EPA*, No. 23-1719 (8th Cir. May 26, 2023).

Thus, by the time the EPA finalized its federal plan, there was a strong likelihood—if not a near certainty—that the federal implementation would *not* go into effect for all "23 upwind states," as intended. 88 Fed. Reg. at 36667. Armed with that likelihood, any reasonable decisionmaker would have stopped to consider this question: Will the federal-implementation plan still be an effective, "efficient[,] and equitable solution" for the covered upwind States if it does not apply collectively to all of them? *See id.* at 36719. The EPA never seriously grappled with that inquiry, even though many courts had already stayed its actions. Instead, the EPA uncritically proceeded under the assumption that its plan would go into effect for all "23 upwind states." *Id.* Along related lines, the EPA never acknowledged the serious federalism implications of its plan, including the likelihood that the federal plan would *not* apply uniformly to all 23 upwind states that the EPA intended to cover. *See id.* at 36858; *see also* 88 Fed. Reg. at 49301; 88 Fed. Reg. at 67105.

The EPA also never adequately considered a smaller, severed version of the federal plan. True, the EPA asserted, without legal analysis, that its plan would be severable. *Id.* at 36693. But its reasoning was conclusory at best: that the federal plan should be severable because some air-quality regulation is better than none. *See id.* That broad brush dodges the key question of whether the federal implementation plan remains a fair and effective division of emission-reduction responsibilities when its application is not uniform. Take, as just one consideration, the issue of competitive balance among States. Upwind states actually subject to the federal plan will face significant compliance burdens and other economic injuries. *Below* 23–26. They will thus be at a competitive disadvantage to upwind States exempt from the plan. The EPA's severability rationale gives this and other consequences of unequal application (including consequences for private parties) no thought. In short, if the EPA's some-regulation-is-better-than-nothing approach counts as reasoned decisionmaking, then anything does.

*

At bottom, the federal-implementation plan is arbitrary and capricious. It no longer achieves its original goal to set federal emission-reduction standards for 23 upwind States. And the federal plan's failures were both predictable and inevitable. During its rulemaking, the EPA failed to grapple with the regulatory mess it created when it took a combined regulatory action against more than 20 different States; and then forced them to accept a *single*, coordinated federal plan. The EPA's desire to force a square peg (a federal air-quality plan) into a round hole (a cooperative, state-driven system) was always going to be a poor fit. Because the EPA failed to confront that reality, it failed to engage in the reasoned decisionmaking required under the Administrative Procedure Act.

3. The D.C. Circuit did not explain its reasons for denying the States a stay. *See* App.A-1–2. But two objections to the States' arguments, that the EPA raised in briefing below, are worth addressing here.

First, the state applicants' arguments do *not* amount to a collateral attack on the disapprovals of their state-implementation plans. As mentioned already, Ohio and Indiana did not challenge the EPA's disapproval of their state plans. (Remember, however, that West Virginia did. *West Virginia v. EPA*, No. 23–1418 (4th Cir.).) It follows that Ohio and Indiana will be subject to regulatory plans that are different from the plans they proposed. But it does not follow that they must accept an unlawful federal-implementation plan. Here, because the federal plan takes a multi-state approach, its lawfulness is necessarily intertwined with the lawfulness of the EPA's various state-plan disapprovals. Put another way, the potential effects of "a contemporaneous and closely related rulemaking" process were something the EPA needed to consider when promulgating its federal plan. *Portland Cement Ass'n*, 665 F.3d at 187. The EPA's failure to do so renders the federal plan unlawful. The state applicants—as regulated States under the federal plan—are free to challenge the federal plan, and they could not have done so before the EPA finalized the plan.

Second, this Court's decision in *EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489 (2014), does nothing to upset the States' arguments. There, the Court resolved a procedural issue and two merits issues. Procedurally, the Court held that States could challenge a federal-implementation plan even though they had not challenged the disapproval of their "particular" state-implementation plans. *Id.* at 507. The Court said that the "gravamen" of the States' challenge was not the illegality of disapproval, but instead that the EPA failed to meet statutory obligations before imposing a federal-implementation plan. *Id.* at 507. So too for Ohio and Indiana. The gravamen of their challenge is not the disapproval of their particular state plans. Rather, they challenge the EPA's failure to engage in reasoned decisionmaking, based on its failure to consider the consequences of litigation involving *other* States. On the merits, *Homer* held that once the EPA has found a state plan inadequate, it may issue a federal plan without giving the State further guidance. *Id.* at 508. The Court further held that the EPA may consider costs in allocating "emission reductions among upwind States." *Id.* at 524. Neither of those holdings relieve the EPA of its obligation to ensure that any federal plan is reasoned and follows the law—so those holdings are irrelevant to this case.

II. The States, their industries, and their citizens will be irreparably harmed without a stay.

Without a stay, the States have sustained—and will continue to sustain—serious, irreparable injuries. Before explaining why, however, the States pause for a coda. Although the Fourth Circuit stayed the EPA's state-plan disapproval as to one of the state applicants (West Virginia), absent further action that stay lasts only through October. *See Order*, ECF. 39, *West Virginia v. U.S.*, No. 23-1418 (4th Cir. Aug. 10, 2023). Thus, a stay is still essential for preventing further irreparable harm to all the state applicants.

Turn now to the harm inflicted by the federal-implementation plan. As explained in full shortly, the States are being harmed by the time, money, and other resources spent on complying with an unlawful federal mandate. *See, e.g.*, App.B-6, 9–10 (Hodanbosi Decl. ¶¶14–15, 22–25); *see* App.C-13–16 (Crowder Decl. ¶¶40–44); App.D-3, 4–11 (Lane Decl. ¶¶5, 7–22); App.E-5–6 (Farah Decl. ¶¶12–15). Because these costs are unrecoverable against the federal government, the States are irreparably harmed every day that passes without a stay. *See Thunder Basin Coal Co. v. Reich*, 510 U.S. 200, 220-21 (1994) (Scalia, J., concurring in part); *see also Whitman-Walker Clinic, Inc. v. U.S. Dep't of Health & Hum. Servs.*, 485 F. Supp. 3d 1, 58 (D.D.C. 2020) (same and collecting examples); *Commonwealth v. Biden*, 57 F.4th 545, 556 (6th Cir. 2023).

For one thing, the federal plan directly imposes significant compliance burdens on the States. Under the federal plan, the States are responsible for issuing or updating Title V permits for covered sources within the State. *See* 88 Fed. Reg. at 36843–44; App.B-7–8 (Hodanbosi Decl. ¶¶18–19); App.C-14 (Crowder Decl. ¶41). Because each permit is unique to the needs of each facility, each permitting process will require rounds of drafting, staff review, public notice, public meetings, and responses to public comments. App.C-14–16 (Crowder Decl. ¶¶41–43); *see* App.B-7–8 (Hodanbosi Decl. ¶¶18–19). The permitting process is thus lengthy, resource intensive, and costly. The States should not have to deplete their coffers while waiting to see how this litigation—which could go on for months or, likely, years—plays out.

The compliance costs borne by the States do not end there. The federal plan also makes States responsible for ensuring that covered sources adequately monitor their emissions. *See* 88 Fed. Reg. at 36843; 40 C.F.R. §70.4. As a result, the States are currently expending significant resources to ensure that sources in their boundaries are aware of their obligations under the federal plan—which include monitoring, recordkeeping, and reporting obligations. *See Ohio EPA Correspondence with State*

Sources, (Aug. 23, 2023), https://perma.cc/83CB-9BZW. The States, in addition, ensure that covered sources within their borders are fitted with the necessary technology for monitoring emissions so that the sources can show compliance with the federal plan. *See id.*; App.B-10 (Hodanbosi Decl. ¶24). Consequently, the States must divert resources away from permitting other infrastructure projects—such as new and expanding power facilities—in order to comply with their compliance burdens under the federal plan. *See* App.C-15–16 (Crowder Decl. ¶43). That is no small matter: stopping or slowing progress on other critical infrastructure projects harms the public welfare.

The federal plan inflicts still other economic injuries on the petitioner States. It will severely undermine the States' electricity-generation capacity and destabilize the States' power grids. *See, e.g.*, App.B-3–6 (Hodanbosi Decl. ¶¶7–15); App.D-3–8, 10–11 (Lane Decl. ¶¶5–14, 17–19, 22); App.E-4–6 (Farah Decl. ¶¶10–15); PJM Interconnection, *Energy Transition in PJM: Resource Retirements, Replacements & Risk* (Feb. 24, 2023), https://perma.cc/PQA7-9P6K; *see also* North American Electric Reliability Corporation, *2023 Summer Reliability Assessment Infographic* (May 2023) at 6, https://perma.cc/A9G6-B398. PJM Interconnection—an entity that coordinates power in Ohio, West Virginia, and parts of Indiana—specifically identified the federal plan as a potential catalyst, among others, for "a significant amount of generation retirements within a condensed time frame." *Energy Transition in PJM: Resource Retirements, Replacements & Risk* at 7.

These electric-grid emergencies are not distant possibilities. One such emergency recently came to pass. App.B-5–6, 14–21 (Hodanbosi Decl. ¶13 and Exhibit A). In December 2022, PJM notified the United States Department of Energy that impending cold weather would threaten the electric grid that PJM operates and potentially cause an electricity shortage. *Id.* The Department responded by issuing an Emergency Order that temporarily suspended air-quality regulations and capacity limits on power sources, thus narrowly avoiding a disaster. *Id.* These emergencies are certain to increase in frequency as the federal plan forces more electricity generators into early retirement. And they threaten the States' operations and industries, and could leave the States' citizens unable to heat or cool their homes affordably, if at all. *See, e.g.*, App.D-3, 4–11 (Lane Decl. ¶¶5, 7–22).

Finally, the EPA's attempt at top-down control contradicts its obligation to respect the States' sovereign authority to regulate air quality within their borders under the Act. This "dictatorial" approach impedes the States' sovereignty by elevating the EPA to the role of primary regulator. *Texas*, 2023 U.S. App. LEXIS 13898 at *28; *Texas*, 829 F.3d at 434. A stay will protect the States' sovereignty from unlawful infringement while this case is decided on the merits.

III. Staying the federal plan will promote the public interest and will not substantially harm others.

The "public interest lies in a correct application of the federal constitutional and statutory provisions upon which the claimants" seek relief. *Coal. to Def. Affirmative Action v. Granholm*, 473 F.3d 237, 252 (6th Cir. 2006) (Sutton, J.) (quotations omitted). That is why the balance of the equities and the public interest merge when the government is a party: enjoining unlawful government action inflicts no legally cognizable harm. *See Nken*, 556 U.S. at 435. Taken independently, too, both of these factors counsel in favor of a stay.

For one thing, the EPA faces no undue harm if the federal plan is stayed. The EPA is responsible for delaying the implementation of the 2015 air-quality standards. It sat for several years on the various state-plan submissions—well past the eighteen-month deadline by which it was to act—before denying them and imposing the federal plan. Any delay is thus a problem of the EPA's own doing. True enough, a stay would reduce the incentives to bring emissions into immediate compliance with the federal plan. But if the plan is illegal, the States should not be forced to comply with it. And the EPA's own actions, exempting a dozen States from the plan and over 75% of the emissions it sought to reduce, confirms that a pause while this case is decided on the merits will not harm the EPA or the country at large. At any rate, covered sources within the States would remain subject to the prior good-neighbor regimes, so this is not an all-or-nothing scenario.

Staying the federal plan also promotes the public interest in applying the law "correct[ly]." *Biden*, 57 F.4th at 556 (quotations omitted). Because the federal plan is arbitrary and capricious, staying its implementation is one step closer to applying the law correctly. Further, the public has a strong interest in having reliable electricity. The affected sources, which includes providers of natural gas, "provide power to … homes, farms, businesses and industries." *Hoosier Energy Rural Elec. Coop., Inc. v. John Hancock Life Ins. Co.*, 588 F. Supp. 2d 919, 934 (S.D. Ind. 2008). If sources' ability to provide reliable electricity "is imperiled," the States may lose the "ability to fulfill [their] mission to the public." *Id.* After all, "a steady supply of electricity"—for example, to heat and cool facilities housing "the elderly, hospitals and day care centers"—is "critical." *Sierra Club v. Ga. Power Co.*, 180 F.3d 1309, 1311 (11th Cir. 1999) (*per curiam*). Staying a rule that threatens grid reliability thus serves the public interest.

CONCLUSION

The Court should stay the federal-implementation plan pending judicial review.

October 2023

Respectfully submitted,

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IN THE

Supreme Court of the United States

KINDER MORGAN, INC.; ENBRIDGE (U.S.) INC.; TRANSCANADA PIPELINE USA LTD.; INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA; AMERICAN PETROLEUM INSTITUTE,

Applicants,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *et al.*,

Respondents.

ON EMERGENCY APPLICATION FOR STAY TO THE HONORABLE JOHN G. ROBERTS, JR., CHIEF JUSTICE AND CIRCUIT JUSTICE FOR THE U.S. COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

EMERGENCY APPLICATION FOR STAY OF FINAL AGENCY ACTION DURING PENDENCY OF PETITIONS FOR REVIEW

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Enbridge (U.S.) Inc. is a wholly-owned subsidiary of Enbridge Inc., a diversified energy company headquartered in Calgary, Canada. Enbridge (U.S.) Inc.'s holdings include natural gas pipelines regulated by the Federal Energy Regulatory Commission. Enbridge Inc. is a publicly traded company that trades on the New York and Toronto stock exchanges. Enbridge, Inc. has no parent companies, and no publicly held company owns a 10 percent or greater interest in Enbridge, Inc.

TransCanada PipeLine USA Ltd. is an indirectly owned subsidiary of TC Energy Corporation. TC Energy Corporation is a federally registered Canadian corporation, with its headquarters in Calgary, Alberta. TC Energy Corporation is a publicly held corporation with no parent corporation. No entity (whether publicly or privately held) has an ownership interest in TC Energy Corporation of 10% or more.

Interstate Natural Gas Association of America ("INGAA") hereby states that INGAA is a national trade association that represents interstate natural gas transmission pipeline companies. INGAA has no parent corporation, and no publicly held corporation has a 10% or greater ownership in INGAA.

American Petroleum Institute ("API") hereby states that API is a national trade association that represents all segments of America's natural gas and oil industry. API has no parent corporation, and no publicly held corporation has a 10% or greater ownership in API.

PARTIES TO THE PROCEEDINGS

The parties to D.C. Circuit Case No. 23-1157 (lead case), consolidated with Case Nos. 23-1181, 23-1183, 23-1190, 23-1191, 23-1193, 23-1195, 23-1199, 23-1200, 23-1201, 23-1202, 23-1203, 23-1205, 23-1206, 23-1207, 23-1208, 23-1209, and 23-1211 are listed below:

Applicant Kinder Morgan, Inc. is Petitioner in Case No. 23-1181; Applicants Interstate Natural Gas Association of America and American Petroleum Institute are Petitioners in Case No. 23-1193; Applicant Enbridge (U.S.) Inc. is Petitioner in Case No. 23-1202; and Applicant TransCanada PipeLine USA Ltd. is Petitioner in Case No. 23-1205.

Respondent State of Utah is Petitioner in Case No. 23-1157.

Respondents States of Ohio, Indiana, and West Virginia are Petitioners in Case No. 23-1183.

Respondent American Forest and Paper Association is Petitioner in Case No. 23-1190.

Respondent Midwest Ozone Group is Petitioner in Case No. 23-1191.

Respondents Associated Electric Cooperative, Inc.; Ohio Valley Electric Corporation; Wabash Valley Power Association, Inc. d/b/a Wabash Valley Power Alliance; America's Power; National Rural Electrification Cooperative Association; and Portland Cement Association are Petitioners in Case No. 23-1195.

Respondent National Mining Association is Petitioner in Case No. 23-1199.

Respondent American Iron and Steel Institute is Petitioner in Case No. 23-1200.

Respondent State of Wisconsin is Petitioner in Case No. 23-1201.

Respondent American Chemistry Council is Petitioner in Case No. 23-1203.

Respondent Hybar LLC is Petitioner in Case No. 23-1206.

Respondent U.S. Steel Corporation is Petitioner in Case No. 23-1207.

Respondent Union Electric Company d/b/a Ameren Missouri is Petitioner in Case No. 23-1208.

Respondent State of Nevada is Petitioner in Case No. 23-1209.

Respondent Arkansas League of Good Neighbors is Petitioner in Case No. 23-1211.

Respondent City Utilities of Springfield, Missouri is Intervenor for Petitioners in the consolidated cases.

Respondents the United States Environmental Protection Agency and Michael S. Regan, Administrator U.S. EPA, are Respondents in all consolidated cases listed above.

Respondents City of New York; Commonwealth of Massachusetts; Commonwealth of Pennsylvania; District of Columbia; Harris County, Texas; State of Connecticut; State of Delaware; State of Illinois; State of Maryland; State of New Jersey; State of New York; State of Wisconsin; Air Alliance Houston; Appalachian Mountain Club; Center for Biological Diversity; Chesapeake Bay Foundation; Citizens for Pennsylvania's Future; Clean Air Council; Clean Wisconsin; Downwinders at Risk; Environmental Defense Fund; Louisiana Environmental Action Network; Sierra Club; Southern Utah Wilderness Alliance; and Utah Physicians for a Healthy Environment are Intervenors for Respondent, U.S. EPA.

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**TO THE HONORABLE JOHN G. ROBERTS, JR.,
CHIEF JUSTICE OF THE SUPREME COURT AND
CIRCUIT JUSTICE FOR THE D.C. CIRCUIT:**

Applicants Kinder Morgan, Inc., Enbridge (U.S.) Inc., TransCanada PipeLine USA Ltd., Interstate Natural Gas Association of America, and American Petroleum Institute, respectfully ask this Court to immediately stay the effectiveness of the final rule (Rule) of the United States Environmental Protection Agency (EPA) entitled *Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards*, 88 Fed Reg. 36,654 (June 5, 2023) as it applies to engines used for pipeline transportation of natural gas. The Applicants have petitioned for review of the Rule in the United States Court of Appeals for the District of Columbia Circuit and filed stay motions in that court requesting that the Rule's applicability to pipeline engines be stayed pending judicial review. In a split decision, the D.C. Circuit denied these and other stay motions on September 25, 2023.

INTRODUCTION

In the Rule, EPA established a uniform, federal program to enforce stringent emissions limits for 23 States that may be contributing to increased pollution levels in nearby States. Consistent with similar past rulemakings, the Rule requires operators of power plants within those States to implement control technologies to reduce emissions. The Rule also, for the first time, reaches into 20 states to regulate gas-fired reciprocating internal combustion engines (pipeline engines) used to efficiently transport natural gas along pipelines across the United States.

The Applicants and their members own and operate hundreds of thousands of miles of natural gas pipelines and transport the vast majority of natural gas consumed in the

United States. The Rule requires that thousands of pipeline engines achieve certain emission-rates limits by May 1, 2026. This date is flat-out impossible for all subject pipeline engines to achieve. Indeed, even to make progress on achieving compliance by that date, operators must significantly impair their ability to serve residential and commercial natural gas and electric power demand across the United States in the short term—making it all the more remarkable that EPA made no effort to even discuss the impacts of its Rule with the Federal Energy Regulatory Commission, the agency charged with ensuring the safe and reliable transportation of natural gas.

Applicants are entitled to a stay pending appeal because: they are likely to succeed on the merits; they will suffer irreparable injury absent a stay; and the balance of harms and public interest favors a stay.

As a threshold matter, EPA had to disapprove over 20 state implementation plans before the agency could adopt its national Rule. EPA's disapprovals of those state plans are currently under challenge in seven federal circuits, and *every one of those courts* has stayed EPA's disapproval of the underlying state plans. Yet EPA continues to implement the Rule—no longer a uniform, national rule—despite it being stayed in a majority of the states in which it was meant to apply.

On top of this foundational flaw, EPA violated the Clean Air Act and the Administrative Procedure Act by: failing to identify the "amounts" of emissions from pipeline engines under the Clean Air Act that significantly contribute to nonattainment or interfere with maintenance in a downwind state; failing to comport with past practice; and failing to justify its approach. And on top of that, EPA adopted an overly broad applicability criterion for pipeline engines that is inconsistent with its own definition of sources that "significantly contribute."

Taken together, this Rule's fundamental predicate *and* substantive particulars are lacking. If this Rule is not arbitrary and capricious, no rule is.

If this Court does not stay the Rule, there will be natural gas supply interruptions while the courts consider the legality of the Rule and operators struggle to bring pipeline engines into compliance with an arbitrary standard. Add the enormous compliance costs of nearly one billion dollars that Applicants will bear over that period, and the Rule causes the exact type of irreparable injury that merits a stay.

Finally, the public interest favors a stay. An agency's compliance with the law is always in the public interest. And, unless stayed, EPA's unlawful rule threatens disruption to a reliable supply of natural gas for customers throughout the country, including for heating and cooking in homes and businesses, as a fuel for electric power generation, and as a critical input in industrial processes.

Applicants support sensible emissions regulations of pipeline engines; but EPA's arbitrary and capricious Rule leaves pipeline engine operators only two choices: (1) be out of compliance with EPA's Rule; or (2) restrict transportation of natural gas, at grave costs to the public. Applicants urge this Court to stay the Rule so they can continue to reliably serve this country's natural gas demand.

STATEMENT

A. Statutory And Regulatory Background

1. The Clean Air Act is a fundamentally federalist statute: it tasks EPA with setting national air quality standards and tasks states with implementing those standards in the first instance through state implementation plans. *See* 42 U.S.C. §§ 7409(a), 7410(a)(2)(C). As "long as the ultimate effect of a State's choice of emission limitations is compliance with the national standards, the State is at liberty to adopt whatever mix of emission limitations it deems best suited to its particular situation." *Train v. Nat. Res. Def. Council, Inc.*, 421 U.S. 60, 79 (1975). If—and only if—a State declines to submit a plan, or if the State's plan does not satisfy the federal standards, EPA promulgates a federal plan in its stead. *Id.* § 7410(c)(1). Relevant here, the Act requires state plans to prohibit sources "within the State from emitting any air pollutant in amounts" that will "contribute significantly" to another State's nonattainment, or interfere with maintenance, of the national standards. *Id.* § 7410(a)(2)(D)(i). This statutory requirement has been referred to as the "good neighbor" provision, or the "transport" provision.

To implement this directive, EPA uses modeling and data from "receptors" that monitor air quality throughout the country to identify the downwind States expected to have problems attaining or maintaining the national standards, and the upwind States that contribute emissions to those downwind receptors. *See* 88 Fed. Reg. at 36,659; *EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489, 500 (2014). To determine which upwind emissions must be eliminated because they "contribute significantly" to downwind nonattainment, EPA considers the cost of reducing the emissions and the impact it will have on downwind air quality. 88 Fed. Reg. at 36,660. "EPA's task is to reduce upwind pollution, but only in 'amounts' that push a downwind State's pollution concentrations above the relevant [air quality standard]." *EME Homer City Generation*, 572 U.S. at 514; *see also* 88 Fed. Reg. at 36,676 (EPA defining "amounts" to mean the "amount of emissions that is in excess of the emissions control strategies that EPA has deemed cost-effective"). Identifying a specific "amounts" threshold is therefore imperative to comply with the transport provision.

In an earlier transport rule, *see* 88 Fed. Reg. at 36,668–69, EPA determined that an upwind State's emissions "'contribute[d] significantly' to downwind nonattainment to the extent its exported pollution both (1) produced one percent or more of a[n] [air-quality standard] in at least one downwind State"; and "(2) could be eliminated most cost-effectively as determined by EPA." *EME Homer*, 572 U.S. at 502–503. Thus, "[a]s EPA interprets the statute, upwind emissions rank as 'amounts [that] . . . contribute significantly to nonattainment' if they . . . can be eliminated under the cost threshold set by the Agency." *Id.* at 518. This Court upheld that approach, concluding that eliminating "amounts that can cost-effectively be reduced is an efficient and equitable solution to the allocation problem the Good Neighbor Provision requires the Agency to address." *Id.* at 519.

This Court made clear, however, that EPA cannot "require a State to reduce its output of pollution by more than is necessary to achieve attainment in every downwind State or at odds with the one-percent threshold the Agency has set." *Id.* at 521. If EPA were to engage in such "over-control," it "will have overstepped its authority." *Id.* at 521–22.

2. In October 2015, EPA promulgated a new, more stringent national air-quality standard for ozone. *See* 88 Fed. Reg. at 36,656. The new ozone standard triggered a duty on

upwind States to revise their state plans to restrict NOx emissions, a precursor to ozone.[1] Under the Clean Air Act, states then had three years to submit their state plans to EPA for approval—meaning the state plans needed to be submitted in 2018. Many states submitted their plans by this deadline or soon thereafter.

EPA did not act expeditiously on the state plans submitted to it by that 2018 statutory deadline: It was not until February 2023—nearly five years later—that the agency announced its decision to disapprove those submissions. *Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards*, 88 Fed. Reg. 9,336 (Feb. 13, 2023). EPA concluded that 23 States did not adequately discharge their obligations under the transport provision of the Act. 88 Fed. Reg. at 36,656. Then, a few months later, EPA issued the Rule establishing its own federal plan to restrict NOx emissions from sources in all 23 States. *Id.*[2]

As relevant here, and for the first time, the Rule directly regulates reciprocating internal combustion engines used in pipeline transportation of natural gas. 88 Fed. Reg. at 36,659.[3] For pipeline engines, EPA imposed emissions limits after examining the available emissions-control technologies and allegedly selected the "cost threshold" that it found "in

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1 Nitrogen oxides—"NOx"—are a type of pollutant formed by atmospheric nitrogen during combustion. NOx can combine with other pollutants in the presence of sunlight to form ozone.

2 The Rule is provided in the Appendix at 1a. Notably, EPA proposed the Rule well before it even disapproved the state plans. *See Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, 87 Fed. Reg. 20,036 (proposed Apr. 6, 2022).

3 The Rule also regulates electric generating units (EGUs) and certain industrial sources (non-EGUs), of which pipeline engines are one.

general, maximized cost-effectiveness—*i.e.*, that achieved a reasonable balance of incremental NOx reduction potential and corresponding downwind air quality improvements" relative to other possible reductions. *Id.* at 36,678. "Taken together," the agency stated, the Rule's emissions limits "will fully eliminate the amount of emissions that constitute the covered states' significant contribution to nonattainment and interference with maintenance in downwind states for purposes of the 2015 ozone [standard]." *Id.* at 36,657. But EPA abandoned its cost threshold in the final Rule while nonetheless requiring the same emission control strategies for industrial sources resulting from that abandoned cost analysis.

The Rule now limits emissions from pipeline engines with a "nameplate rating" of 1,000 horsepower or greater. 40 C.F.R. § 52.41(b). The specific limitations vary based on the type of engine, but each caps the grams of NOx that can be emitted per horsepower-hour. *Id.* § 52.41(c). In arriving at the 1,000-horsepower applicability criterion for pipeline engines, EPA deviated from its approach for several other industrial sources, where EPA used actual emissions amounts exceeding 100 tons per year. Despite wide variance in actual emissions from pipeline engines greater than 1,000 horsepower, EPA contends that the horsepower criterion "reasonably approximates" the 100-ton-per-year applicability criterion that EPA used for other industrial sources. 88 Fed. Reg. at 36,820.

The Rule also sets an impossible compliance deadline given the scale and scope of requirements for pipeline engines. All regulated pipeline engines are required to meet the applicable emissions rate limits by May 1, 2026, less than three years after the Rule's effective date. EPA rationalized this compliance date in part by contending that the *proposed* rule had provided "roughly an additional year of notice." *Id.* at 36,755.

Tacitly acknowledging the Rule's overly broad application, costly requirements, and impossible compliance timeline, EPA tacked on provisions (not proposed at the draft stage) purportedly allowing for one-off exceptions or limited flexibility. Operators may attempt to seek EPA's discretionary approval, on "a case-by-case" basis, for a higher emissions limit for an engine that cannot comply with the applicable limit "due to technical impossibility or extreme economic hardship." 40 C.F.R. § 52.40(e). Operators also may attempt to seek EPA approval for a "Facility-Wide Averaging Plan as an alternative means of compliance," provided that the "total emissions reductions" for all the engines in the facility are "equivalent to or greater than those" that would be achieved if each engine hit its individual limit. *Id.* § 52.41(d). For pipeline engines, EPA may grant a case-by-case compliance extension for units that cannot meet the applicable compliance date "due to circumstances entirely beyond the owner or operator's control" if the owner or operator demonstrates it "has taken all steps possible to install the controls necessary for compliance . . . by the applicable compliance date." *Id.* § 52.40(d)(3).

3. EPA's disapproval of the state plans—the predicate for the nationwide Rule—has been challenged in seven different federal circuit courts. *All seven* have stayed EPA's underlying state plan disapprovals.[4] Acknowledging these stays, EPA has issued two "interim final

[4] Order, *Texas v. EPA*, No. 23-60069, ECF 269-1 (5th Cir. May 1, 2023); Order, *Arkansas v. EPA*, No. 23-1320, ECF 5280996 (8th Cir. May 25, 2023); Order, *Missouri v. EPA*, No. 23-1719, ECF 5281126 (8th Cir. May 26, 2023); Order, *Texas v. EPA*, No. 23-60069, ECF 359-2 (5th Cir. June 8, 2023); Order, *Nevada Cement Co. v. EPA*, No. 23-682, ECF 27.1 (9th Cir. July 3, 2023); Order, *ALLETE, Inc. v. EPA*, No. 23-1776 (8th Cir. July 5, 2023); Order, *Kentucky v. EPA*, No. 23-3216, ECF 39-2 (6th Cir. July 25, 2023); Order, *Utah v. EPA*, No. 23-9509, ECF 010110895101 (10th Cir. July 27, 2023); Interim Stay Order, *West Virginia v. EPA*, No. 23-01418, ECF 39 (4th Cir. Aug. 10, 2023); Order, *Alabama v. EPA*, No. 23-11173 (11th Cir. Aug. 17, 2023). This uniform response from the federal courts of appeals reinforces the primacy

rules" to stay the Rule within the twelve states where the state plan disapprovals have been stayed. *See Federal ''Good Neighbor Plan'' for the 2015 Ozone National Ambient Air Quality Standards; Response to Judicial Stays of SIP Disapproval Action for Certain States*, 88 Fed. Reg. 49,295 (July 31, 2023) (First Interim Final Rule)[5]; *Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards; Response to Additional Judicial Stays of SIP Disapproval Action for Certain States,* 88 Fed. Reg. 67,102, 67,103 (Sept. 29, 2023) (Second Interim Final Rule). EPA has not expressly extended the compliance deadline for pipeline engines in states with stays, however, creating yet more regulatory uncertainty for operators attempting to manage an already impossible timeline. *See* 88 Fed. Reg. at 67,103–04 (stating only that EPA "generally anticipates" that lead times would be "comparable" if/when state SIP disapproval stays are lifted).

B. Procedural History

The States of Indiana, Ohio, Utah, and West Virginia, along with members of multiple affected industries, timely petitioned for review of the Rule in the D.C. Circuit. *See* D.C. Circuit Lead Case No. 23-1157. The following relevant motions to stay the Rule were then filed:

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of States' roles in achieving air quality standards under the Clean Air Act's cooperative federalism approach, and confirms the extent of EPA's overreach. *See* Order, *Texas v. EPA*, No. 23-60069, ECF 269-1, at 17 ("In sum, because the EPA's lack of deference to the States inverts the agency's 'ministerial function' in this system of 'cooperative federalism,' Stay Petitioners have made a strong showing that the EPA acted unlawfully.") (cleaned up). EPA's overly muscular approach to Clean Air Act regulation, coupled with the immense costs to industry, also implicate the Major Questions Doctrine. *See* Br. for Enbridge (U.S.) Inc. 12–13, No. 23-1157 (D.C. Cir. Aug. 4, 2023) (arguing that EPA's action in universally disapproving state plans in favor of a federal plan "runs roughshod over" cooperative federalism and implicates the Major Questions Doctrine).

[5] One of the Applicants has challenged the First Interim Final Rule in the D.C. Circuit. *See Kinder Morgan v. EPA*, D.C. Cir. No. 23-1279 (Sept. 29, 2023).

- Utah moved to stay on July 7, 2023;[6]
- Indiana, Ohio, and West Virginia moved jointly to stay on July 19, 2023;
- Kinder Morgan moved to stay on July 27, 2023;
- API and INGAA moved to stay on July 27, 2023,
- American Forest & Paper Association, Midwest Ozone Group, America's Power, Associated Electric Cooperative, Inc., Deseret Generation & Transmission Co-Operative, National Rural Electric Cooperative Association, Ohio Valley Electric Corporation, Portland Cement Association, Wabash Valley Power Association, Inc., and the National Mining Association moved to stay on August 2, 2023.
- Enbridge moved to stay on August 4, 2023.
- TC Energy moved to stay on August 8, 2023.

A divided panel of the D.C. Circuit denied the stay motions on September 25, 2023. Order, *Utah v. EPA*, No. 23-1157 (D.C. Cir. Sept. 25, 2023) (266a). Judge Walker dissented. *Id.*

REASONS FOR GRANTING THE APPLICATION

Applicants are entitled to a stay if they can establish that (1) they are likely to succeed on the merits; (2) they will be irreparably injured absent a stay; (3) a stay will not substantially injure other parties; and (4) a stay serves the public interest. *Nken v. Holder*, 556 U.S. 418, 434 (2009). The third and fourth factors merge when the government is the opposing party. *Id.* at 435. These Applicants satisfy each factor.[7]

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[6] Utah subsequently moved to hold the briefing for its motion in abeyance because the Tenth Circuit stayed EPA's disapproval of Utah's state plan; the D.C. Circuit granted Utah's request.

[7] Applicants do not need to meet the standard in *Hollingsworth v. Perry*, 558 U.S. 183, 190 (2010), where the Court analyzes likelihood of granting certiorari and the prospect of reversal. In *Hollingsworth*, this Court considered an application for a stay of a lower court or-

I. APPLICANTS ARE LIKELY TO SUCCEED ON THE MERITS.

A. The Legal Predicate For The Rule Is Undermined By Stays Across Seven Circuits.

As an exercise of cooperative federalism, the Clean Air Act assigns to the States the "primary responsibility for assuring air quality." 42 U.S.C. § 7407(a). As such, EPA only has authority to issue a federal plan if a state plan does not comply with the Act. *See id.* § 7410(c)(1). But seven circuit courts—*all* circuits presented with a request to date—have stayed EPA's disapproval of 12 separate state plans. Thus, a majority of the 20 states where the Rule applies to pipeline engines have now had their state plan disapprovals stayed, eliminating the legal predicate for the Rule in those states. *Id.* § 7410(c)(1)(B).

That state of affairs fundamentally undermines the Rule. EPA itself states that the Rule is based on the "combined effect of the entire program *across all linked upwind states*," 88 Fed. Reg. at 36,749 (emphasis added), so the many judicial stays of the state plan disapprovals have profoundly altered the nature and scope of the multi-state Rule EPA proposed, received comments on, analyzed for emissions impacts, and promulgated. The data tells the story: of EPA's total estimated emissions reductions, only 22 percent remain from the states where EPA continues to have authority to enforce the Rule. Appendix at 649a. By sector, only 11 percent of total EGU emissions reductions remain, and only 40 percent of total non-EGU emissions reductions remain. *Id.*

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der pending the filing of petitions for certiorari and mandamus. *Id.* at 185. Here, by contrast, Applicants seek a stay of a federal rule that the D.C. Circuit's motions panel refused to stay. *See Nat'l Fed'n of Ind. Bus. v. Dep't of Labor*, 142 S.Ct. 661 (2022) (per curiam) (applying traditional *Nken* factors and granting stay in analogous posture). Even if *Hollingsworth* applied, however, *see Does 1–3 v. Mills*, 142 S. Ct. 17, 18 (2021) (Barrett, J., concurring) (understanding *Nken*'s first factor to encompass the *Hollingsworth* standard), Applicants would still satisfy that standard given the importance of the issues and the Rule's significant legal flaws.

Given this data, EPA's own rationale for the Rule disintegrates. EPA itself emphasized that the Rule is meant to address interstate ozone transport "on a national scale" and that "consistency in rule requirements across all jurisdictions is vital in ensuring the remedy for ozone transport is 'efficient and equitable.'" 88 Fed. Reg. at 36,691 (quoting *EME Homer*, 572 U.S. at 519). Now, the Rule no longer applies on a "national scale" and imposes inconsistent requirements among states. Similarly, EPA stated that the Rule depends on "a uniform level of emissions reduction . . . the linked upwind states can achieve," *id.* at 36,676, but the Rule is not "uniform" when it applies to less than half the states EPA originally intended.

On top of that, the Rule's ozone-reduction rationale no longer applies. EPA concluded that "the *collective* application of these mitigation measures and emissions reductions are projected to deliver meaningful downwind air quality improvements" of 0.66 parts per billion (ppb) of ozone reduction on average. *Id.* at 36,748 (emphasis added). In proposing and promulgating the Rule, EPA also emphasized that an individual state's contribution may be relatively small, but the "*collective* contribution resulting from multiple upwind states" may not. *Id.* at 36,678 (emphasis added). With 78 percent of the "collective" emission reductions now stayed, it is unclear what, if any, ozone benefit would result; EPA did not analyze the effect of a *partial* rule.

EPA may respond that it considers the Rule severable. *See id.* at 36,693 ("[S]hould a court find any discrete aspect of this document invalid, the Agency believes that the remaining aspects of this rule can and should be implemented to the extent possible."). But severability depends on whether the provisions at issue are actually severable, *Reno v. ACLU*, 521 U.S. 844, 882–83 (1997), meaning whether "the remainder of the regulation could function sensibly without the stricken provision." *MD/DC/DE Broadcasters Ass'n v. FCC*, 236 F.3d 13, 22 (D.C. Cir.), *aff'd on reh'g*, 253 F.3d 732, 734 (D.C. Cir. 2001) (en banc); *see also Minnesota v. Mille Lacs Band of Chippewa Indians*, 526 U.S. 172, 194 (1999) (entirety of order inseverable, "embodying as it did one coherent policy"). Where severance would "severely distort the [agency's] program and produce a rule strikingly different from any the [agency] has ever considered or promulgated," as here, the regulation cannot be severed. *MD/DC/DE Broadcasters*, 236 F.3d at 23. EPA's own statements in briefing on venue drive this home: "[The Rule] depends on the continuing operation of 'interdependent' interstate mechanisms." *Tulsa Cement et al. v. EPA*, EPA's Motion to Dismiss or Transfer Petitions for Improper Venue 16, No. 23-9551 (10th Cir. July 20, 2023). With these interdependencies dissolved by the stays spanning 12 states, and with the Rule's striking difference from the one considered and promulgated, the whole Rule falls apart.

This procedural and substantive mess is compounded by the foundational legal issues with the Rule itself, which we discuss in turn.

B. EPA Failed To Identify Emissions "Amounts" From Non-EGU Sources That Contribute Significantly to Nonattainment, Failed to Explain its Departure From Past Practice, and Failed to Justify its Conclusions.

In its proposed rule, and applying its "uniform cost" framework upheld by *EME Homer*, 88 Fed. Reg. at 36,719, EPA used a "marginal cost threshold of $7,500 per ton" of emissions as the threshold for the "amounts" of emissions to be eliminated for non-EGU sources, including pipeline engines, 87 Fed. Reg. at 20,083. After pipeline companies identified critical flaws in EPA's cost data and analysis during the comment period (including that the Rule would apply to more than three times the number of engines that EPA assumed), EPA jettisoned that threshold as "not reflect[ing] the full range of cost-effectiveness values that are likely present across the many different types of non-EGU industries and emissions units assessed." 88 Fed. Reg. at 36,740, 36,746.

But EPA then made a critical error: it never adopted (or even analyzed) a revised cost threshold reflecting the "amount of emissions that is in excess of the emissions control strategies that EPA has deemed cost-effective." 88 Fed. Reg. at 36,676. Instead, it continued to require the same emissions controls identified at the proposal stage that *were not* reflective of the full range of cost-effectiveness values pipeline engines would face. EPA's flawed Rule thus requires emissions reductions on engines that vastly exceed $7,500 per ton. *See* TC Energy Comment 5 (noting total costs of Rule of $900 million for engines that operate infrequently) (603a); Kinder Morgan Comment 21–26 (noting costs above $100,000/ton and even above $684,169/ton) (543a–548a). EPA's approach runs afoul of the Clean Air Act—and this Court's prior precedent—and arbitrarily and capriciously departs from its own past practice.

First, the Clean Air Act requires EPA to define the "amounts" of pollutants to be reduced. 42 U.S.C. § 7410(a)(2)(D)(i)(I). As the D.C. Circuit has explained, "[i]nterstate contributions cannot be assumed out of thin air." *Michigan v. EPA*, 213 F.3d 663, 684 (2000). Rather, they must be grounded in an "amount." EPA definitively decided to define this amount in this Rule using a cost-effectiveness criterion, where "upwind emissions rank as 'amounts [that] . . . contribute significantly to nonattainment' if they . . . can be eliminated under the cost threshold set by the Agency." *EME Homer*, 572 U.S. at 518; 88 Fed. Reg. at 36,719. EPA maintains that the Rule "continues to apply the same approach as the prior three [interstate transport] rulemakings" for evaluating "amounts" of "significant contribution," which are "represented by cost thresholds." 88 Fed. Reg. at 36,678; *see Maryland v. EPA*, 958 F.3d 1185, 1192 (D.C. Cir. 2020). EPA is wrong. In discarding its proposed cost-effectiveness threshold in the final Rule without ever defining an alternative, EPA failed to determine the statutory "amounts" of emissions required to be eliminated.[8]

Second, EPA's failure to define "amounts" as "represented by a cost threshold" also departs from its own long-held approach. In past ozone transport rules, EPA required industries to install only those control technologies that are cost-effective, based on a defined threshold. *See, e.g.*, 76 Fed. Reg. 48,208, 48,248 (Aug. 8, 2011) ("defin[ing] each state's . . . contribution . . . as the emission reductions available *at a particular cost threshold* in a specific upwind state." (emphasis added)). And when EPA found a cost threshold unrepresentative, it did not require reductions. *See, e.g.*, 70 Fed. Reg. 25,162, 25,214 (May 12, 2005) ("EPA believes it is necessary to have . . . better control cost information for [non-EGUs] before assuming reductions from them."); 81 Fed. Reg. 74,504, 74,508 (Oct. 26, 2016) ("Our analysis shows that there is uncertainty regarding whether or not meaningful, cost-effective non-EGU emission reductions are achievable . . . . Therefore, non-EGU reductions are not included in the final rule.").

Despite admitting that the $7,500 threshold did "not reflect the full range of cost-effectiveness values that are likely present across the many different types of non-EGU industries and emissions units assessed," EPA is still forcing companies to install those same controls it proposed. 88 Fed. Reg. at 36,746. EPA also did *not explain* why it was departing from

[8] EPA may argue in response that the $7,500 threshold was never supposed to be a fixed cost threshold above which emissions reductions would not be required. But the agency's own record belies that claim. EPA said at proposal that it "believes that . . . engines subject to this proposed [rule] can achieve the emissions limit of 1.5 g/hp-hr with the installation and operation" of specified "control technologies *at the marginal cost threshold of $7,500 per ton*." 87 Fed. Reg. at 20,142–43 (emphasis added).

its past practice in defining a cost-effectiveness threshold above which emissions reductions are not required. *See FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515–16 (2009) (reasoned explanation required when agency departs from past practice). Even worse, EPA changed its interpretation in a final rule, without the opportunity for notice and comment. *See Shell Oil Co. v. EPA*, 950 F.2d 741, 747 (D.C. Cir. 1991). Indeed, one commenter noted that "[i]t is unclear how EPA could make the necessary findings for a final rule given the inaccurate data it relies upon." Kinder Morgan Comment 3 (525a). EPA's failure to provide a reasoned explanation "for disregarding facts and circumstances that underlay or were engendered by the prior policy" was arbitrary and capricious. *Encino Motorcars, LLC v. Navarro*, 579 U.S. 211, 222 (2016) (quoting *Fox Television*, 556 U.S. at 515–16).

For the Clean Air Act's requirements to have any meaning, EPA cannot be allowed to choose to define a source's "significant contribution" in terms of whether the source can make cost-effective emissions reductions, identify a threshold for assessing cost-effectiveness, and then deem cost-effectiveness irrelevant by finalizing a Rule that imposes costs vastly exceeding the threshold. *See Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto Ins. Co.*, 463 U.S. 29, 43 (1983) (agency must "articulate a satisfactory explanation for its action," including "a rational connection between the facts found and the choice made.").

EPA likely will respond that the Rule provides a limited exemption process for "certain individual facilities and emissions units [that] may face extreme hardship," 88 Fed. Reg. at 36,747 n.250. But that process is no panacea. First, whether to grant an exemption is committed to EPA's sole discretion. *See* 40 C.F.R. §52.40(e)(2)(B) (demonstration of extreme economic hardship must be to EPA's "satisfaction"). Thus, pipeline companies have no assurance that even an engine with emission-reduction costs far in excess of $7,500/ton would be granted an exemption. Second, to be granted this discretionary cost-based exemption, companies must demonstrate "*extreme* economic hardship"—a standard EPA has never used and has yet to define as a fixed cost-per-ton threshold. *Id*. (emphasis added). And third, by limiting exemptions to "individual facilities and emissions units" on a case-by-case basis, it is unlikely that EPA will grant widespread exemptions even though widespread exemptions will inevitably be necessary.[9] The theoretical availability of occasional exemptions does not save this deeply flawed Rule. *See Ass'n of Oil Pipe Lines v. FERC*, 281 F.3d 239, 244 (D.C. Cir. 2002) ("safety valve" could not "rescue [agency's rule] from systemic errors, for then the exception would swallow the rule").

C. EPA's Compliance Timeline Failed To Consider Natural Gas Reliability Impacts.

The Rule requires the pipeline transportation sector to implement complex control technologies by May 1, 2026—an impossible deadline for pipeline engines. 88 Fed. Reg. at 36,756.[10] These emissions requirements apply to over *three thousand* pipeline engines across the country, *id.* at 36,824, but a retrofit on a *single* engine "requires between 1 and 2 ½ years to complete (from inception to completion of commissioning)," INGAA Comment 36

[9] There are only two vendors nationwide with the necessary equipment and experience to retrofit most pipeline engines, and those contractors have never processed the scale and magnitude of requests that the Rule forces. *See* Kinder Morgan Comment 28 (550a); *NOx Emissions Control Technology Installation Report Timing for Non-EGU Sources, Final Report*, EPA-HQ-OAR-2021-0668-1077, 68, A-1–A-3 (Mar. 14, 2023) (Timing Report) (454a, 456a–458a). EPA ignored these logistical impediments as well.

[10] EPA contends that "the publication of the proposal" also "provided roughly an additional year of notice." *Id.* That contention is meritless. *See Window Covering Mfrs. Ass'n v. Consumer Prod. Safety Comm'n*, No. 22-1300, 2023 WL 5918899, at *13 (D.C. Cir. Sept. 12, 2023) (rejecting agency's assertion that the proposed rule gave additional notice to the regulated industry in concluding agency's chosen effective date was arbitrary and capricious).

(500a).[11] EPA's refusal to provide a feasible compliance deadline jeopardizes the safe and reliable transportation of natural gas in the United States. *See id.* at 34–42 (explaining impossibility of EPA's proposed compliance date for pipeline engines and noting that EPA had not evaluated pipeline reliability impacts of its proposed compliance date) (498a–506a); *Memphis Light, Gas & Water Div. v. Craft*, 436 U.S. 1, 18 (1978) (recognizing "utility service" as a "necessity of modern life"). Notwithstanding the gravity of this concern, EPA failed to consider the adverse impacts to natural gas reliability when setting the compliance deadline, which will result in natural gas and electric power service interruptions during the times of year when downstream users, including homes, businesses, institutions (such as schools and hospitals), and electric power plants, need fuel the most.

With over three thousand regulated engines, basic math dictates that pipeline companies will need to take numerous pipeline engines offline simultaneously (for months each, once the operator secures the permits, contractor, and parts) to even attempt to meet the 2026 deadline. These outages will in turn cause a "large-scale reduction in output of natural gas," Kinder Morgan Comment 29, 36–37 (551a, 558a–559a), and "prevent[] [natural gas] shippers from transporting as much gas as their users require," INGAA Comment 42 (506a). Despite the importance of natural gas reliability and industry comments, EPA offers scant discussion on—and no meaningful support for—its conclusion that the Rule would not cause supply shortages.

[11] This is in part because pipeline engines are a far cry from the small engines in cars and trucks. Pipeline engines typically weigh at least 100,000 pounds and can weigh as much as 365,000 pounds, and they are highly complex and integrated machines. Kinder Morgan Comment 28 (550a).

First, EPA relies on a cursory report it commissioned, and which it did not publish until the final Rule, which suggests that operators could simply "coordinate outages" of pipeline engines to minimize natural gas reliability concerns and service disruptions. EPA, *NOx Emissions Control Technology Installation Report Timing for Non-EGU Sources, Final Report*, EPA-HQ-OAR-2021-0668-1077, ES-8 (Mar. 14, 2023) (Timing Report) (385a). That rationale is both misplaced and unsupported. Pipelines are linear. Pipeline engines are spread every 40 to 100 miles along the pipeline network to ensure sufficient flow of natural gas. If one engine is taken offline for retrofits, there is limited ability for an engine immediately ahead or behind it to substitute for its capacity at high demand, and there is no ability to substitute engine capacity across different pipelines. Further, even if such coordination were physically possible, EPA does not consider that pipeline capacity cannot be coordinated among different pipeline operators, given that pipeline companies are competitors—meaning agreements between them to allocate capacity would trigger serious antitrust concerns.[12] And each pipeline operator can have unique delivery points to distribution companies, gas-fired electric generators, or industrial customers that no other operator can access, eliminating any opportunity for coordination. EPA's proposed solution is thus no solution at all.

Second, the Timing Report expressly states that its authors "were not able to complete an evaluation of" the reliability concerns raised during the comment period. Timing Report at ES-8 (385a). Given that the Timing Report represents EPA's only analysis of pipeline reliability concerns at all, EPA admits that it "failed to consider [this] important aspect of the

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[12] *See In re Musical Instruments & Equip. Antitrust Litig.*, 798 F.3d 1186, 1191 (9th Cir. 2015) ("[A]greements among competitors to fix prices, divide markets, and refuse to deal . . . [are] inherently anticompetitive horizontal agreements [that] violate the Sherman Act per se.").

problem." *State Farm*, 463 U.S. at 43. EPA's lack of consideration for natural gas reliability is especially stark in contrast with the lengthy electric-sector reliability evaluation (where the agency at least paid lip service to the issue for EGUs), particularly where gas-fired power plants themselves rely on pipelines for fuel. *See* 88 Fed. Reg. at 36,772 n.301 (noting report EPA prepared to evaluate electric-sector reliability).

EPA's failure to consider these adverse impacts drew ire from a Federal Energy Regulatory Commissioner, who observed with respect to the Rule that "[a]lthough EPA responds to arguments regarding how the EGU portion of its rule affects electric reliability, . . . EPA [did] not ever consider the impacts that the timeline for compliance for non-EGUs would have on electric reliability or residential uses." Commissioner James Danly, *Response to Questions for the Record for June 13, 2023 House Energy & Commerce Oversight Hearing* 23–24, https://perma.cc/C757-3DD3 (637a–638a). Quite so.

The Rule's unrealistic compliance timeline cannot be saved by the fact that the Rule allows an operator to request a case-by-case extension in exceptional circumstances. Indeed, for the reasons discussed above, extensions will almost certainly be required across the board, rather than only in one-off or exceptional cases.

EPA thus "entirely failed to consider an important aspect of the problem" when adopting the compliance timeline—namely, the widespread impacts to natural gas reliability—and the Rule is arbitrary and capricious as a result. *State Farm*, 463 U.S. at 43; *see Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 544–545, 552 (D.C. Cir. 1983) (vacating EPA's gasoline lead standard under the Clean Air Act in part for lack of record evidence that compliance timeline was achievable).

D. EPA's 1,000-Horsepower Applicability Criterion For Pipeline Engines Is Unlawful.

EPA also erred by adopting an initial applicability criterion that captures many pipeline engines whose emissions are far *below* the threshold EPA used to screen out sources that do not "contribute significantly."

In determining which sources to regulate, and before applying the marginal cost threshold discussed above, EPA "focused on assessing emission units that emit > 100 [tons per year] of NOx." EPA, *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* at 3 (Feb. 28, 2022) (736a). EPA's decision to screen out sources that emit less than that amount necessarily represents a determination that those sources do not "significantly contribute" to downwind nonattainment. *Maryland*, 958 F.3d at 1204.

For some other non-EGU sources, EPA used 100 tons per year of actual emissions as a threshold for the applicability criterion. *See* 88 Fed. Reg. at 36,825 (cement and concrete product manufacturing); *id.* at 36,827 (iron and steel mills and ferroalloy manufacturing); *id.* at 36,829 (glass and glass product manufacturing). For pipeline engines, by contrast, EPA did not. Instead, it implemented the 100-tons-per-year threshold by using a horsepower-based proxy, lumping in all pipeline engines with a design capacity of 1,000 horsepower or greater and asserting that this criterion "reasonably approximates" the 100-tons-per-year threshold. 88 Fed. Reg. at 36,820; *see also* 87 Fed. Reg. 20,036, 20,142 (proposed Apr. 6, 2022).

At the proposal stage, EPA projected that its horsepower proxy would cover only 307 engines nationwide. 87 Fed. Reg. at 20,090. And it projected that a significant majority of those engines would exceed the 100-tons-per-year threshold: EPA estimated that "over 200 engines" out of 307 "emitted greater than 100 [tons per year]." EPA, *Technical Support Document (TSD) for the Final Rule: Final Non-EGU Sectors TSD* at 4 (Mar. 2023) (271a).

Commenters demonstrated that EPA had wildly underestimated the proposed rule's reach. *See* INGAA Comment 8–9 (472a–473a (stating that INGAA's members alone operate 1,380 units that would be regulated, contrasting with EPA's estimate of 307 engines in total). In the Final Rule, EPA admitted that the 1,000-horsepower criterion had "captured more units than the EPA intended," including "low-use units and some units with emissions of less than 100 tons per year." 88 Fed. Reg. at 36,819, 36,821. That was an understatement: EPA now projects that 3,005 units are subject to the Rule—almost *ten times* its initial projection. *Id.* at 36,824. Yet EPA continued to project that fewer than 300 units would meet the 100-tons-per-year threshold for coverage under the Rule. *See* EPA, *Non-EGU Facilities and Units.xlsx* (Mar. 2023) (listing about 260 engines above the threshold), https://perma.cc/UDK9-LRKU (downloads file).

EPA nonetheless persisted in its plan to regulate all units with a 1,000-horsepower rating, refusing to adjust its applicability criterion to address the mismatch of actual emissions as compared to potential emissions. 88 Fed. Reg. at 36,819–21. This was unlawful.

First, EPA's applicability criterion results in regulation of a significant number of engines that, by EPA's own logic, do not "contribute significantly." That exceeds EPA's authority under the statute: EPA may not require emissions reductions "at odds with the . . . threshold the Agency has set." *EME Homer*, 572 U.S. at 521.

Second, EPA's finding that a 1,000-horsepower rating "reasonably approximates" the 100-tons-per-year threshold, 88 Fed. Reg. at 36,820, "runs counter to the evidence before the agency," *State Farm Mut. Auto. Ins. Co.*, 463 U.S. at 43. EPA's own data shows that fewer than one in ten of the units subject to the rule meet the 100-tons-per-year threshold. The rest are collateral damage. A "reasonable approximation" is one that fairly, if inexactly, captures the target group. *Cf. Worldcom, Inc. v. FCC*, 238 F.3d 449, 459 (D.C. Cir. 2001). Rather than a "reasonable approximation," the Rule amounts to a tenfold expansion of EPA's regulatory reach beyond sources that "contribute significantly."

Third, EPA's reasons for declining to adjust the applicability criterion are arbitrary and capricious. *Balt. Gas & Elec. Co. v. FERC*, 954 F.3d 279, 285 (D.C. Cir. 2020) (agency has a "duty to explain inconsistent treatment" of regulated entities). EPA tried to justify its overreach by claiming that the hundreds of units below the emissions threshold could one day exceed 100 tons per year and it is "not possible to guarantee without an effective emissions control program that all such units could not increase emissions in the future." 88 Fed. Reg. at 36,821. But the statute applies only to sources that "*will* . . . contribute significantly," 42 U.S.C. § 7410(a)(2)(D)(i) (emphasis added), not that "could potentially" do so in the future. And, contrary to EPA's assertion, it is possible to ensure that units do not increase their emissions: As it did in the Rule for other sources, EPA could impose a reporting obligation and require compliance with emissions limits if the 100-tons-per-year threshold is exceeded. *Cf.* 40 C.F.R. § 52.45(b)(1)–(2) (exempting low-use boilers from all but recordkeeping and reporting requirements unless they exceed certain usage thresholds).

II. ABSENT A STAY, PIPELINE OPERATORS—AND THEIR CUSTOMERS—WILL BE IRREPARABLY HARMED.

Absent a stay, pipeline operators will be forced to curtail natural gas shipments—causing supply interruptions—while they take pipeline engines offline for retrofits to meet EPA's infeasible and unsupported compliance timeline and spend hundreds of millions of dollars in just the 12 to 18 months after the Rule's effective date (August 4, 2023) on those retrofits. Interrupted natural gas supplies no doubt constitute irreparable injury—to the public and pipeline companies. Likewise, compliance costs that cannot be recovered are irreparable. *Thunder Basin Coal Co. v. Reich*, 510 U.S. 200, 220–21 (1994) (Scalia, J., concurring in part and concurring in the judgment) ("[C]omplying with a regulation later held invalid almost always produces the irreparable harm of nonrecoverable compliance costs."); *see also Ala. Ass'n of Realtors v. HHS*, 141 S. Ct. 2485, 2489 (2021) (per curiam) (noting financial impact "with no guarantee of eventual recovery" put applicants "at risk of irreparable injury").

Natural gas reliability. Natural gas pipelines—the backbone of the country's natural gas supply infrastructure—cannot retrofit all their engines in time to meet EPA's compliance deadline of May 1, 2026. *Supra* at 17–21. To even have a chance of meeting that deadline, pipeline operators will need to take engines offline during peak-demand seasons (winter and summer) to retrofit all the engines required.[13]

Pipeline engines are large, complex pieces of machinery, and *a single* retrofit project can take from one to two-and-a-half years from engineering development to commissioning. Yeager Decl. ¶ 19 (716a). The installation phase itself can take between three to six months per engine or six to 12 months per compressor station. Wooden Decl. ¶ 11 (702a). Before construction can even begin, pipeline operators need to have state permits in hand, and the permit process itself can take over a year, even without delays. Grubb Decl. ¶ 52 (681a).

[13] Pipeline operators must do so to achieve the emissions limits in states where the Rule is not stayed, and as noted above, EPA offered only vague assurances that compliance timelines would be pushed back to account for existing state plan disapproval stays. *See* 88 Fed. Reg. at 67,103–04 (EPA "generally anticipates" that lead times would be "comparable" if/when state plan disapproval stays are lifted).

Adding this all together, pipeline operators will have a short window of time to retrofit engines, and these retrofits would require taking hundreds of engines offline during peak-demand seasons, risking natural gas reliability for winter heating (November to March) and for use in power plants to serve air conditioning loads in the summer (May to September). Grubb Decl. ¶¶ 61–69 (685a–693a); Wooden Decl. ¶¶ 11–12 (702a–703a). This forced-march timeline sharply contrasts with pipeline operators' practice of scheduling service or other necessary outages during *lower* demand periods. Grubb Decl. ¶ 62 (685a–686a).

Two case studies illustrate that reliability concerns are concrete and imminent. Kinder Morgan performed computer simulation modeling on two of its pipelines to evaluate the pipeline capacity impacts that will result if Kinder Morgan attempts to meet the May 1, 2026, compliance date for as many of its engines as possible. Grubb Decl. ¶¶ 64–66 (687a–689a). First, for its pipeline system serving the Chicago area—which serves approximately 60 percent of the Chicago natural gas market—Kinder Morgan found that its delivery capacity during peak-demand winter days in Chicago would fall 20 percent short of demand. *Id.* ¶ 66 (689a). That shortfall equates to approximately 1,761,000 homes' worth of natural gas usage that could not be supplied during a peak-demand winter day. *Id.* (689a). Second, the same modeling showed that Kinder Morgan's pipeline segment serving the Gulf Coast region would experience shortfalls of delivered natural gas equating to hundreds of thousands of homes going unserved during both summer and winter periods. *Id.* ¶ 67 (690a–691a). Kinder Morgan's natural gas system in this region also serves six natural gas-fired power plants, which collectively provide electricity to millions of customers. *Id.* (690a–691a).

EPA will likely argue that pipelines have sufficient spare capacity to absorb required engine outages, given pipelines' "average annual capacity utilization." *See* Timing Report at

ES-8, 8 (385a, 394a) (citing average annual capacity utilization of 40 percent). This is not a solution; indeed, it only reveals EPA's deep misunderstanding of the pipeline industry. *Average* capacity utilization bears little on the ability to serve *peak* demand. Natural gas demand is highly seasonal; pipelines experience much higher demand when weather is extremely hot or extremely cold, and demand ebbs in the spring and fall. For a particular pipeline, then, "40 percent utilization" could mean a much lower percent utilization during low-demand times in spring and fall and over 95 percent during peak summer and winter demand. And if the weather turns hot or cold in these "off-peak" months, utilization jumps higher.

Relying on a 40% average capacity utilization also presupposes that engine capacity can be borrowed across the entire industry. The capacity a pipeline engine provides is highly location- and pipeline-specific. Even within a single pipeline, there is little ability for sharing the work of engines too far upstream or downstream in the pipeline. And in certain highly populated regions, there is only one pipeline company that can deliver to core urban areas, making sharing among different pipeline companies a physical impossibility.

The Rule's purported compliance flexibilities will not avoid irreparable injury either. First, EPA estimates that only one-third of engines would require controls because of its allowance for facility-wide emissions averaging. 88 Fed. Reg. at 36,760. But EPA's analysis of this supposed option is based on unrepresentative and extremely limited data and provides operators little practical ability to reduce the number of engines requiring retrofits. Grubb Decl. ¶¶ 35–44 (670a–676a) (noting that EPA only evaluated 10 compressor stations (out of 713 total), all of which have far more engines than the average compressor station, and therefore show more benefit from averaging than would be experienced in practice).[14] Second, and as discussed above (at 16–17), the case-by-case emissions limit for *extreme* economic hardship is only meant to apply on a limited basis, and EPA has not provided a specific cost threshold that would qualify, making it impossible for companies to reasonably rely on this option. Yager Decl. ¶ 9 (711a). Third, the compliance timeline extensions would be required for a massive number of pipeline engines. For example, Kinder Morgan alone has concluded it would need an extension for approximately half of its engines that do not currently meet the emissions limits. Grubb Decl. ¶ 48 (679a). And to qualify, operators must "take[] *all steps possible* to install controls for compliance with the applicable requirements," 40 C.F.R. § 52.40(d)(3), meaning they need to begin performing engine retrofits promptly and through the pendency of litigation. Finally, EPA has sole discretion to grant any of these compliance flexibilities; operators cannot reasonably rely on EPA to do so.

Compliance costs. Individual pipeline companies face steep compliance costs in the 12 to 18 months after the Rule's effective date. As of July 2023, Enbridge expected to incur \$350 million;[15] Kinder Morgan expected to incur \$270 million;[16] and TC Energy expected to incur \$75 million.[17] Adding these costs plus its other members' costs, INGAA estimated that its members will need to spend at least *several hundred million dollars* on engine retrofits

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14 The averaging approach also offers little flexibility in practice because it presents a constantly moving target based on a "rolling" lookback period. Grubb Decl. ¶ 44 (676a).

15 Wooden Decl. ¶ 13 (703a).

16 Grubb Decl. ¶¶ 6, 28 (653a–654a, 666a–667a).

17 Yeager Decl. ¶ 9 (722a).

over the same period. Yager Decl. ¶ 10 (712a). Absent a stay, if a court later invalidates the Rule, pipeline companies will not be able to recover these substantial costs.

The total costs expected for retrofits of engines to meet the Rule's emissions rates limits are even more jaw-dropping. As of July 2023, Kinder Morgan anticipated $1.8 to $2.1 billion;[18] Enbridge anticipated $1 billion;[19] and TC Energy anticipated $600 million.[20] In total, INGAA estimated that its members will have to spend up to approximately *six billion dollars.* Yager Decl. ¶ 10 (712a). And even these astronomical amounts do not include costs resulting from curtailed shipments and other opportunity costs. Grubb Decl. ¶¶ 45–46, 70–73 (676a–679a, 693a–695a) (noting costs of modernizations and emissions reduction projects placed on hold, as well as "reservation charge credits"—i.e., refunds—to customers for interrupted pipeline service); Wooden Decl. ¶ 14 (703a) (system modernization plans being deferred). These burdensome costs constitute the types of irreparable injury other circuit courts have necessarily found when issuing stays of EPA's state plan disapprovals. *See, e.g.*, Order at 23, *Texas v. EPA*, No. 23-60069, ECF 269-1 ("Stay Petitioners will be forced to spend billions of dollars in compliance costs . . . .").

To avert natural gas delivery interruptions during peak seasons and to prevent pipeline companies from facing exorbitant compliance costs, this Court should stay the Rule.

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18 Grubb Decl. ¶¶ 6, 26 (653a, 666a).

19 Wooden Decl. ¶ 14 (703a).

20 Yeager Decl. ¶¶ 9, 15 (722a, 724a).

III. THE BALANCE OF HARMS AND THE PUBLIC INTEREST WEIGH HEAVILY IN FAVOR OF A STAY.

Even where a compelling public interest exists, "our system does not permit agencies to act unlawfully even in pursuit of desirable ends." *Ala. Ass'n of Realtors*, 141 S. Ct. at 2490. Accordingly, "there is a substantial public interest 'in having governmental agencies abide by the federal laws that govern their existence and operations.'" *League of Women Voters of United States v. Newby*, 838 F.3d 1, 12 (D.C. Cir. 2016) (citation omitted). Here, given EPA's unlawful actions, the public interest strongly supports a stay.

A stay is also warranted because EPA, and only EPA, is responsible for the Rule's constrained timeline, given the immense gap between States' 2018 plan submissions and EPA's 2023 disapprovals. As the Fifth Circuit observed, "EPA's multi-year delay" in disapproving states' implementation plans "undercuts any claim that time is of the essence when it comes to imposing" the Rule. Order at 24, *Texas v. EPA*, 5th Cir. No. 23-60069, ECF 269-1. Where EPA set an unreasonable compliance deadline for pipeline engines, and where EPA was the source of the delay in the first instance, EPA cannot argue that it or the public is harmed by a stay. On the contrary, the public interest in ensuring the consistent and reliable supply of natural gas to downstream consumers, including homes, businesses, and electric power plants, tips sharply in favor of a stay.

CONCLUSION

For the foregoing reasons, Applicants respectfully request an immediate stay of the Rule's provisions for pipeline engines.

Respectfully submitted,

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October 13, 2023

No. 23A_____

In the Supreme Court of the United States

AMERICAN FOREST & PAPER ASSOCIATION; AMERICA'S POWER; ASSOCIATED ELECTRIC COOPERATIVE, INC.; DESERET POWER ELECTRIC COOPERATIVE; MIDWEST OZONE GROUP; NATIONAL MINING ASSOCIATION; THE NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION; OHIO VALLEY ELECTRIC CORPORATION; THE PORTLAND CEMENT ASSOCIATION; WABASH VALLEY POWER ALLIANCE,

Applicants,

v.

ENVIRONMENTAL PROTECTION AGENCY AND MICHAEL S. REGAN, ADMINISTRATOR,

Respondents.

EMERGENCY APPLICATION FOR IMMEDIATE STAY OF FINAL AGENCY ACTION PENDING DISPOSITION OF PETITION FOR REVIEW

To the Honorable John G. Roberts, Jr.,
Chief Justice of the Supreme Court of the United States and Circuit Justice for the District of Columbia Circuit

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PARTIES TO THE PROCEEDINGS

A. Parties to this Application

i. D.C. Cir. No. 23-1190, *Am. Forest & Paper Assoc. v. EPA*

Petitioner: American Forest & Paper Association.

Respondents: The United States Environmental Protection Agency; Michael S. Regan, EPA Administrator.

Intervenors: City Utilities of Springfield, Missouri.

ii. D.C. Cir. No. 23-1191, *Midwest Ozone Group v. EPA*

Petitioner: Midwest Ozone Group.

Respondents: The United States Environmental Protection Agency; Michael S. Regan, EPA Administrator.

Intervenors: City Utilities of Springfield, Missouri

iii. D.C. Cir. No. 23-1195, *Associated Electric Cooperative, Inc. v. EPA*

Petitioners: Associated Electric Cooperative, Inc.; Deseret Generation & Transmission Co-Operative, d/b/a Deseret Power Electric Cooperative; Ohio Valley Electric Corporation; Wabash Valley Power Association, Inc., d/b/a Wabash Valley Power Alliance; America's Power; National Rural Electric Cooperative Association; Portland Cement Association.

Respondents: The United States Environmental Protection Agency; Michael S. Regan, EPA Administrator.

Intervenors: City Utilities of Springfield, Missouri

iv. D.C. Cir. No. 23-1199, *National Mining Association v. EPA*

Petitioner: National Mining Association.

Respondents: The United States Environmental Protection Agency; Michael S. Regan, EPA Administrator.

Intervenors: City Utilities of Springfield, Missouri

B. Additional Parties to these Consolidated Cases

i. D.C. Cir. No. 23-1157, *State of Utah v. EPA*

Petitioner: The State of Utah, by and through its Governor, Spencer J. Cox, and its Attorney General, Sean D. Reyes.

Respondents: The United States Environmental Protection Agency; Michael S. Regan, EPA Administrator.

Intervenors: City Utilities of Springfield, Missouri; City of New York; Commonwealth of Massachusetts; Commonwealth of Pennsylvania; District of Columbia; Harris County, Texas; State of Connecticut; State of Delaware; State of Illinois; State of Maryland; State of New Jersey; State of New York; State of Wisconsin; Air Alliance Houston; Appalachian Mountain Club; Center for Biological Diversity; Chesapeake Bay Foundation; Citizens for Pennsylvania's Future; Clean Air Council; Clean Wisconsin; Downwinders at Risk; Environmental Defense Fund; Louisiana Environmental Action Network; Sierra Club; Southern Utah Wilderness Alliance; Utah Physicians for a Healthy Environment.

ii. D.C. Cir. No. 23-1181, *Kinder Morgan v. EPA*

Petitioner: Kinder Morgan, Inc.

Respondents: The United States Environmental Protection Agency; Michael S. Regan, EPA Administrator.

Intervenors: City Utilities of Springfield, Missouri; Commonwealth of Massachusetts; Commonwealth of Pennsylvania; District of Columbia; Harris County, Texas; State of Connecticut; State of Delaware; State of Illinois; State of Maryland; State of New Jersey; State of New York; State of Wisconsin; City of New York.

iii. D.C. Cir. No. 23-1183, *State of Ohio v. EPA*

Petitioners: State of Ohio; State of West Virginia; State of Indiana.

Respondents: The United States Environmental Protection Agency; Michael S. Regan, EPA Administrator.

Intervenors: City Utilities of Springfield, Missouri; City of New York; Commonwealth of Massachusetts; Commonwealth of Pennsylvania; District of Columbia; Harris County, Texas; State of Connecticut; State of Delaware; State of Illinois; State of Maryland; State of New Jersey; State of New York; State of Wisconsin.

iv. D.C. Cir. No. 23-1193, *Interstate Natural Gas Association of America v. EPA*

Petitioners: Interstate Natural Gas Association of America; American Petroleum Institute.

Respondents: The United States Environmental Protection Agency; Michael S. Regan, EPA Administrator.

Intervenors: City Utilities of Springfield, Missouri.

v. D.C. Cir. No. 23-1200, *American Iron and Steel Institute v. EPA*

Petitioners: American Iron and Steel Institute.

Respondents: The United States Environmental Protection Agency; Michael S. Regan, EPA Administrator.

Intervenors: City Utilities of Springfield, Missouri.

vi. D.C. Cir. No. 23-1201, *State of Wisconsin v. EPA*

Petitioners: State of Wisconsin.

Respondents: The United States Environmental Protection Agency; Michael S. Regan, EPA Administrator.

Intervenors: City Utilities of Springfield, Missouri; Sierra Club; Midwest Ozone Group.

vii. D.C. Cir. No. 23-1202, *Enbridge (U.S.) Inc. v. EPA*

Petitioners: Enbridge (U.S.) Inc.

Respondents: The United States Environmental Protection Agency; Michael S. Regan, EPA Administrator.

Intervenors: City Utilities of Springfield, Missouri.

viii. D.C. Cir. No. 23-1203, *American Chemistry Council v. EPA*

Petitioners: American Chemistry Council; American Fuel & Petrochemical Manufacturers.

Respondents: The United States Environmental Protection Agency; Michael S. Regan, EPA Administrator.

Intervenors: City Utilities of Springfield, Missouri.

ix. D.C. Cir. No. 23-1205, *TransCanada Pipeline USA Ltd. v. EPA*

Petitioners: TransCanada Pipeline USA Ltd.

Respondents: The United States Environmental Protection Agency; Michael S. Regan, EPA Administrator.

Intervenors: City Utilities of Springfield, Missouri.

x. D.C. Cir. No. 23-1206, *Hybar LLC v. EPA*

Petitioners: Hybar LLC

Respondents: The United States Environmental Protection Agency; Michael S. Regan, EPA Administrator.

Intervenors: City Utilities of Springfield, Missouri.

xi. D.C. Cir. No. 23-1207, *United States Steel Corporation v. EPA*

Petitioners: United States Steel Corporation.

Respondents: The United States Environmental Protection Agency; Michael S. Regan, EPA Administrator.

Intervenors: City Utilities of Springfield, Missouri.

xii. D.C. Cir. No. 23-1208, *Union Electric Company v. EPA*

Petitioners: Union Electric Company, d/b/a Ameren Missouri.

Respondents: The United States Environmental Protection Agency; Michael S. Regan, EPA Administrator.

Intervenors: City Utilities of Springfield, Missouri.

xiii. D.C. Cir. No. 23-1209, *State of Nevada v. EPA*

Petitioners: State of Nevada.

Respondents: The United States Environmental Protection Agency; Michael S. Regan, EPA Administrator.

Intervenors: City Utilities of Springfield, Missouri.

xiv. D.C. Cir. No. 23-1211, *Arkansas League of Good Neighbors v. EPA*

Petitioners: Arkansas League of Good Neighbors.

Respondents: The United States Environmental Protection Agency; Michael S. Regan, EPA Administrator.

Intervenors: City Utilities of Springfield, Missouri.

CORPORATE DISCLOSURE STATEMENT

Pursuant to Rule 29.6, applicants state as follows:

AMERICAN FOREST & PAPER ASSOCIATION

The American Forest & Paper Association ("AF&PA") is a continuing association of individuals operated for the purpose of promoting the general interests of its membership. The AF&PA represents nearly 87% of the pulp, paper, packaging, and tissue products industry which employs 925,000 skilled workers. The AF&PA is a trade association and has no outstanding shares or debt securities in the hand of the public. It has no parent company, and no publicly held company has a 10% or greater ownership interest in AF&PA.

AMERICA'S POWER

America's Power is a nonprofit membership corporation organized under the laws of the District of Columbia and is recognized as a tax-exempt trade association by the Internal Revenue Service under Section 501(c)(6) of the Internal Revenue Code. America's Power is the only national trade association whose sole mission is to advocate at the federal and state levels on behalf of coal-fueled electricity, the coal fleet, and its supply chain. America's Power supports policies that promote the use of coal to assure a reliable, resilient, and affordable supply of electricity to meet our nation's demand for energy.

America's Power is a trade association. It has no parent corporation, and no publicly held company owns a 10% or greater interest in America's Power.

ASSOCIATED ELECTRIC COOPERATIVE, INC.

Associated Electric Cooperative, Inc. ("AECI") is a rural electric cooperative that provides wholesale power and high-voltage transmission to its six regional generation and transmission cooperative member-owners. In addition to providing power sales and transmission service to its member cooperatives, AECI also takes and provides transmission service through enabling transmission agreements with and makes off-system power sales to various counterparties in the United States. These six regional generation and transmission cooperatives, in turn, supply wholesale power to fifty-one distribution cooperatives in Missouri, three distribution cooperatives in southeast Iowa, and nine distribution cooperatives in northeast Oklahoma, serving more than 2,000,000 customers at 910,000 meters. AECI has no parent company, and no publicly held company has a 10% or greater ownership interest in AECI.

DESERET POWER ELECTRIC COOPERATIVE

Deseret Generation & Transmission Co-Operative d/b/a Deseret Power Electric Cooperative ("Deseret") certifies that it is a nonprofit, regional generation and transmission cooperative, owned by its five member systems, serving approximately 65,000 customers in Utah, Colorado, Wyoming, Nevada, and Arizona. Neither Deseret, nor its member cooperatives issue stock, and therefore no publicly held company owns 10% or more of their stock.

MIDWEST OZONE GROUP

The Midwest Ozone Group ("MOG") is a continuing association of organizations and individual entities operated to promote the general interests of its membership on matters related to air emissions and air quality. MOG has no parent companies, subsidiaries, or affiliates that have issued shares or debt securities to the public, although specific individuals in the membership of MOG have done so. MOG has no outstanding shares or debt securities in the hands of the public. It has no parent company, and no publicly held company has a 10% or greater ownership interest in MOG.

NATIONAL MINING ASSOCIATION

The National Mining Association ("NMA") is a nonprofit national trade association that represents the interest of the mining industry, including every major coal company operating in the United States. NMA has approximately 280 members, whose interests it represents before Congress, the administration, federal agencies, the courts, and the media. NMA is not a publicly held corporation. It has no parent corporation, and no publicly held company has 10% or greater ownership interest in NMA.

NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

The National Rural Electric Cooperative Association ("NRECA") is the nonprofit national trade association for electric cooperatives. On behalf of its members, NRECA participates in administrative and judicial proceedings involving or affecting its members' interests. NRECA has no parent company, and no publicly held company has a 10% or greater ownership interest in NRECA. NRECA is an incorporated entity.

OHIO VALLEY ELECTRIC CORPORATION

The Ohio Valley Electric Corporation ("OVEC") is a corporation originally formed by a consortium of utility companies for purposes of constructing and operating electric generating units to serve the electric energy needs of uranium processing facilities owned by the United States Department of Energy. OVEC owns the Kyger Creek generating station in Ohio, and OVEC's wholly owned subsidiary Indiana-Kentucky Electric Corporation owns the Clifty Creek generating station in Indiana. OVEC has no parent company. American Electric Power Company, Inc., and Buckeye Power, Inc., each owns greater than 10% of the equity in OVEC.

PORTLAND CEMENT ASSOCIATION

The Portland Cement Association ("PCA"), founded in 1916, is the premier policy, research, education, and market intelligence organization serving America's cement manufacturers. PCA represents a majority of U.S. cement production capacity. PCA promotes safety, sustainability, and innovation in all aspects of construction, fosters continuous improvement in cement manufacturing and distribution, and generally promotes economic growth and sound infrastructure investment. PCA is a trade association and has no parent corporation, and no publicly held company owns a 10% or greater interest in PCA.

WABASH VALLEY POWER ALLIANCE

Wabash Valley Power Association, Inc. d/b/a Wabash Valley Power Alliance ("WVPA") certifies that it is a nonprofit, generation and transmission cooperative, owned by twenty-three member-owned rural cooperative systems, serving more than 330,000 homes, businesses, farms, and schools – impacting more than a million people – across 50 counties in Indiana, 30 counties in Illinois, and four counties in Missouri. Neither WVPA, nor its member cooperatives issue stock, and therefore no publicly held company owns 10% or more of their stock.

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TO THE HONORABLE JOHN G. ROBERTS, JR., CHIEF JUSTICE OF THE SUPREME COURT OF THE UNITED STATES AND CIRCUIT JUSTICE FOR THE DISTRICT OF COLUMBIA CIRCUIT:

The Applicants, ten industry parties consisting of national trade associations and individual electric generating companies, respectfully request an immediate stay of the Environmental Protection Agency's ("EPA") final rule entitled "Federal 'Good Neighbor Plan' for the 2015 Ozone National Ambient Air Quality Standards," 88 Fed. Reg. 36,654 (June 5, 2023) ("Federal Plan"). The Applicants have petitions for review of the Federal Plan pending in the United States Court of Appeals for the District of Columbia Circuit and, due to the immediate harm from the Federal Plan, moved for a stay pending that court's review. A divided panel of that court denied the motion, with Judge Walker stating he would have stayed the Federal Plan.

The Applicants agree with and incorporate the Application by Ohio, Indiana, and West Virginia filed with this Court on October 13, 2023. The Applicants will not repeat the States' arguments here but will amplify the reasons why the Federal Plan merits this Court's review, is likely unlawful, and poses immediate and irreparable harm to various industries, including electric generation, paper, steel, cement, and mining, as demonstrated in more detail in the declarations accompanying this application.

INTRODUCTION

This case involves a stubborn refusal by EPA to admit that the legal foundation for a massive, multi-state, regulatory program (the "Federal Plan") is irreparably flawed—as an extraordinary consensus of seven courts of appeals have recognized. EPA's willful decision to move forward has simultaneously abrogated the rights of States to regulate air pollution within their borders and improperly forced industries regulated by the Federal Plan into the immediate expenditure of hundreds of millions of dollars pending the lower court's review, all while jeopardizing the reliability of the electric grid.

The Clean Air Act's "core principle" is "cooperative federalism." *EPA* v. *EME Homer City Generation, L.P.*, 572 U.S. 489, 511 n.14 (2014). States assume "primary responsibility for assuring air quality…." 42 U.S.C. § 7407(a). EPA may step into the role of the States and issue a rule like the Federal Plan only if EPA lawfully determines that a State's plan violates the statute. *Id.* § 7410(c)(1).

After missing its statutory deadline to review State plans by years, EPA disapproved 21 State plans *en masse*. 88 Fed. Reg. 9336 (Feb. 13, 2023). State and industry commenters informed EPA that those State-plan disapprovals were likely unlawful, and federal courts of appeals began agreeing, swiftly issuing stays of individual state plan disapprovals. Relying on its unlawful state-plan disapprovals as the legal predicate, EPA nevertheless published the Federal Plan for those 21 States, plus an additional two States. 88 Fed. Reg. at 36,654. Ultimately, entities in 12 of the 23 affected States challenged and sought stays of their disapprovals in various courts of appeals. Every single one of those courts (the Fourth,[1] Fifth, Sixth, Eighth, Ninth, Tenth, and Eleventh Circuits) have granted stays.

[1] The stay of the disapproval of West Virginia's State plan is administrative, pending the Fourth Circuit's consideration of that State's stay motion. *West Virginia* v. *EPA*,

When seven courts of appeals find that the legal prerequisite for the Federal Plan is likely unlawful, EPA should realize that something has gone awry. Rather than admit the error of its ways, however, EPA has pressed forward with implementing its Federal Plan in the remaining 11 States—despite the fact that EPA premised the rule on its applicability to 23 states, arguing "[n]ationwide consistency in approach is particularly important in the context of interstate ozone transport…." *Id.* at 36,673. Because of the removal of the 12 stayed States, the Federal Plan is a shell of its original design, eviscerating EPA's analysis underpinning the rule, which addressed only a 23-State program as a whole. In other words, EPA is implementing an 11-state mutant rule that it did not analyze, provide notice of, or take comment on. That momentous action to force its multi-state federal plan, heedless of warnings from court after court that its central pillars are fundamentally unsound, violates the Clean Air Act and the Administrative Procedure Act.

Yet, this irredeemably flawed Federal Plan is now in effect. If this Court does not enter a stay, the Federal Plan will continue to harm the sectors of industry subject to it. By EPA's own estimates, the Federal Plan will cost between $8.2 and $13 billion, with regulated entities like Applicants and their members incurring between $770 and $910 million per year during the course of litigation. *Id.* at 36,852. Costs on individual entities are crushing and are being imposed with full force in the 11 States where the Federal Plan is in effect. For example, just one regulated source, Applicant

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No. 23-1418 (4th Cir. Aug. 10, 2023) (stay pending argument scheduled for October 27, 2023).

Ohio Valley Electric Corporation, states that it "will begin to incur costs within the next six months" and will be "required to spend between $80-$100 million in the next two years." Brown Decl. ¶¶32, 36. A stay from this Court is the only way for sources subject to the Federal Plan to avoid this irreparable harm.

Accordingly, Applicants respectfully request the Court to enter a stay of EPA's Federal Plan during the pendency of their petitions for review.

OPINION BELOW

The D.C. Circuit's order denying the Applicants' motion for a stay is unpublished and may be found at App'x 1. EPA's Federal Plan is published at 88 Fed. Reg. 36,654 (June 5, 2023) and reprinted beginning at App'x 2. The unpublished order notes that while the majority of the panel comprised of Judges Pillard, Walker, and Childs denied the stay, "Judge Walker would stay the federal implementation plan in question."

JURISDICTION

This Court has jurisdiction over this Application pursuant to 28 U.S.C. § 1254(1) and authority to grant the Applicants relief under the Administrative Procedure Act, 5 U.S.C. § 705, the Clean Air Act, 42 U.S.C. § 7607, and the All Writs Act, 28 U.S.C. § 1651(a).

STATUTORY AND REGULATORY PROVISIONS

Pertinent statutory and regulatory provisions are reprinted beginning at App'x 268.

STATEMENT

I. Statutory Background

Congress embedded directly into the Clean Air Act the principle of cooperative federalism, expressly stating that "[e]ach State shall have the primary responsibility for assuring air quality within the entire geographic area comprising such State…." 42 U.S.C. § 7407(a). EPA establishes national ambient air quality standards ("NAAQS") for certain pollutants, including ozone. *Id.* §§ 7408, 7409. Each State then must develop within three years a State implementation plan that "specif[ies] the manner in which [the NAAQS] will be achieved and maintained." *Id.* §§ 7407(a), 7410(a)(1).

These plans must satisfy several statutory requirements, including the Act's "Good Neighbor" provision. *Id.* § 7410(a)(2)(D)(i)(I). That provision delegates to each State the task of ensuring no "emissions activity within the State" will emit "in amounts which will … contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any" NAAQS." *Id.*

Once a State develops and submits its plan, EPA "shall approve" the plan within 18 months "if it meets all of the applicable requirements of" the Clean Air Act. *Id.* § 7410(k)(3); *see also Union Elec. Co.* v. *EPA*, 427 U.S. 246, 257 (1976). Only if EPA lawfully determines that a State plan violates the statute may EPA promulgate a "Federal implementation plan" for that State. 42 U.S.C. § 7410(c)(1).

When EPA is permitted to issue a federal plan, it "cannot require a State to reduce its output of pollution by more than is necessary" to ensure the State will not contribute significantly to another State's inability to attain or maintain the NAAQS.

EME Homer, 572 U.S. at 521-22. If EPA does, it engages in unlawful "over-control." *Id.* "EPA has a statutory duty to avoid over-control…." *Id.* at 523.

II. EPA's Promulgation of State Implementation Plan Disapprovals and the Federal Plan

In 2015, EPA lowered the NAAQS for ozone from 75 to 70 parts per billion. 80 Fed. Reg. 65,292, 65,293-94 (Oct. 26, 2015). This required States to develop implementation plans for the revised NAAQS, including plans addressing the Good Neighbor provision, within three years (*i.e.*, by October 26, 2018). 42 U.S.C. § 7410(a)(1). After States submitted their plans, EPA had a statutory duty to approve or disapprove them within eighteen months (*i.e.*, no later than April 2020). *Id.* § 7410(k)(1)-(3). After blowing past this statutory deadline by years, EPA issued proposed disapprovals for 19 States on February 22, 2022,[2] followed by proposed disapprovals for an additional four States on May 24, 2022.[3] Commenters repeatedly warned EPA that these proposed disapprovals were unlawful because they were based on unlawful reasoning. *See, e.g.*, EPA, 2015 Ozone NAAQS Interstate Transport SIP Disapprovals – Response to Comment (RTC) Document at 12, 15, 29, 33, 57, 81, 189, *available at* https://t.ly/ikB1A.

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[2] 87 Fed. Reg. 9545 (Feb. 22, 2022) (Alabama, Mississippi, Tennessee); 87 Fed. Reg. 9798 (Feb. 22, 2022) (Arkansas, Louisiana, Oklahoma, Texas); 87 Fed. Reg. 9838 (Feb. 22, 2022) (Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin); 87 Fed. Reg. 9498 (Feb. 22, 2022) (Kentucky); 87 Fed. Reg. 9463 (Feb. 22, 2022) (Maryland); 87 Fed. Reg. 9533 (Feb. 22, 2022) (Missouri); 87 Fed. Reg. 9484 (Feb. 22, 2022) (New York, New Jersey); 87 Fed. Reg. 9516 (Feb. 22, 2022) (West Virginia). Comments on each of these proposals were due on April 25, 2022.

[3] 87 Fed. Reg. 31,443 (May 24, 2022) (California); 87 Fed. Reg. 31,485 (May 24, 2022) (Nevada); 87 Fed. Reg. 31,470 (May 24, 2022) (Utah); 87 Fed. Reg. 31,495 (May 24, 2022) (Wyoming). Comments on each of these proposals were due on July 25, 2022.

Before the deadline for submitting comments on the proposed disapprovals of the State plans had even expired (and before EPA had even proposed to disapprove some of the States' plans), EPA proposed a comprehensive *federal* implementation plan to regulate emission sources through a single multi-state program. 87 Fed. Reg. 20,036, 20,073 (Apr. 6, 2022) (noting it was "promulgating FIPs to address these obligations on a nationwide scale"). Commenters again repeatedly warned EPA that going forward with a federal plan would be unlawful because the state-plan disapprovals—which are the legal predicate of a federal plan under the Clean Air Act—were unlawful. *See* 88 Fed. Reg. at 36,672-75; EPA, Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards: Response to Public Comments on Proposed Rule [87 FR 20036, April 6, 2022] at 2-6, 9-11, 145-48, 152-55, *available at* bit.ly/3EaNAi8.

Despite the warnings regarding the unlawful nature of EPA's proposed disapproval, the Agency finalized the disapprovals of the plans for 21 States in February 2023. 88 Fed. Reg. 9336 (Feb. 13, 2023). A mix of states and industry parties in 12 States challenged their state-plan disapprovals in their respective circuits and moved for stays of the disapprovals. By late May 2023, the Fifth Circuit, Sixth Circuit, and the Eighth Circuit had issued stays of the disapprovals for five States,[4]

[4] *Texas v. EPA*, No. 23-60069 (5th Cir. May 1, 2023) (Texas and Louisiana); *Arkansas v. EPA*, No. 23-1320 (8th Cir. May 25, 2023); *Missouri v. EPA*, No. 23-1719 (8th Cir. May 26, 2023); *Kentucky v. EPA*, No. 23-3216 (6th Cir. May 31, 2023) (administrative stay pending consideration of stay motion that was granted in July 2023, *see infra* note 5).

concluding that EPA's state plan disapprovals were likely unlawful. Meanwhile, stay motions were pending for various other courts of appeals.

EPA nonetheless moved forward on June 5, 2023, with publishing the Federal Plan, which covers 23 States and became effective August 4, 2023. 88 Fed. Reg. at 36,654. During the time between the publication of the Federal Plan and its effective date, the wave of federal courts of appeals issuing stays of the state plan disapprovals became a tsunami. Every single one of the 12 state-plan disapprovals that was challenged has now been stayed.[5]

In sum, every circuit to have considered the issue—the Fourth, Fifth, Sixth, Eighth, Ninth, Tenth, and Eleventh Circuits—has stayed EPA's disapprovals, explicitly or implicitly finding that the States and industries challenging those disapprovals are likely to succeed on the merits.

III. The Federal Plan Before and After the Court-Ordered Stays of the State Plan Disapprovals

EPA has recognized in two interim final rules that it cannot impose its plan in the 12 States where EPA's state-plan disapprovals have been stayed because those state plan disapprovals form the legal predicate for the Federal Plan.[6] As a result of

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[5] *Texas v. EPA*, No. 23-60069 (5th Cir. June 8, 2023) (Mississippi); *Nevada Cement Company v. EPA*, No. 23-682 (9th Cir. July 3, 2023) (Nevada); *Allete, Inc. v. EPA*, No. 23-1776 (8th Cir. July 5, 2023) (Minnesota); *Kentucky v. EPA*, No. 23-3216 (6th Cir. July 25, 2023); *Oklahoma v. EPA*, No. 23-9514 (10th Cir. July 27, 2023); *Utah v. EPA*, No. 23-9509 (10th Cir. July 27, 2023); *Alabama v. EPA*, No. 23-11173 (11th Cir. Aug. 17, 2023); *West Virginia v. EPA*, No. 23-1418 (4th Cir. Aug. 10, 2023) (administrative stay pending argument scheduled for October 27, 2023).

[6] Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards: Response to Judicial Stays of SIP Disapproval Action for Certain States, 88 Fed. Reg. 49,295 (July 31, 2023) (Arkansas, Kentucky, Louisiana, Mississippi,

the removal of these 12 States from the Federal Plan, however, the plan that EPA is now imposing in the remaining 11 States bears little resemblance to the one it proposed, took comment on, and finalized.

This Court in *EME Homer* described EPA's chosen methodology for constructing a federal Good Neighbor plan; EPA started with that same methodology for the Federal Plan at issue here. *See id.* at 36,741, 36,748. Under this methodology, EPA identifies the (upwind) States that its air quality modeling predicted would be contributing more than *de minimis* amounts of ozone to (downwind) States that will have difficulty attaining the NAAQS. *See EME Homer*, 572 U.S. at 500-01. It then determines what emissions controls would be "cost-effective" by calculating which controls would produce the "combined effect … on air quality in downwind States" necessary to eliminate significant upwind ozone contribution, assuming every upwind State uniformly expended the same amounts to control their emissions. *Id.* at 501. "EPA estimated, for example, the amount each upwind State's [ozone-causing] emissions would fall if all pollution sources within each State employed every control measure available at a cost of $500 per ton or less." *Id.* So if upwind States A and B were both linked to downwind State C, EPA's methodology requires the reductions necessary to make upwind contributions to State C insignificant, assuming both

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Missouri, Texas); Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards: Response to Additional Judicial Stays of SIP Disapproval Action for Certain States,88 Fed. Reg. 67,102 (Sept. 9, 2023) (Alabama, Minnesota, Nevada, Oklahoma, Utah, West Virginia).

States A and B expended the same amount per tons of emissions in control measures. *See id.* at 519-20.

Next, "[f]or each regulated upwind State, EPA created an annual emissions 'budget,'" which "represented the quantity of pollution an upwind State would produce in a given year if its in-state sources implemented all pollution controls available at the chosen cost thresholds." *Id.* at 502. Thus, the emissions budget for each State stems from EPA's "cost-effectiveness" methodology, which assumes the same expenditure on emissions controls "applied uniformly to all regulated upwind States" to achieve EPA's desired "combined effect" downwind. *Id.* at 501-02. Finally, EPA pairs these budgets with a "cap-and-trade" system allocating each upwind State's "emission budget among its in-state sources" and allowing sources emitting below their allocation to "sell unused 'allocations' to sources" in any other upwind State that is part of the federal plan. *Id.* at 503 & n.10.

EPA thus describes the Federal Plan as a "national-scale, multi-state" federal implementation plan to address "interstate transport of ozone-causing pollutants through a series of integrated multi-state emissions allowance trading programs for power plants [and] uniform requirements for certain, high-emitting non-power plant industrial sources." EPA Resp. to Pet.'s Mot. To Sever, Doc. No. 2018488, *Utah v. EPA*, No. 23-1157 (D.C. Cir. Sept. 22, 2023). Indeed, this is how EPA designed the Federal Plan to operate. *See* 88 Fed. Reg. at 36,673 ("The approach of this [federal implementation plan] ensures both national consistency across all states and consistency and continuity with our prior interstate transport actions for other NAAQS."); *id.* at 36,691 (noting "the purpose of this rule is to address the interstate transport of ozone on a national scale" and that "upwind regions associated with each receptor typically span at least two, and often far more, states").

The Federal Plan that EPA originally designed no longer exists as a result of the court-ordered stays. Nearly 90% of the power plant emissions that EPA contemplated serving as both the basis for its emissions limitations and for a robust emissions allowance trading market have been removed from the program. Similarly, 60% of the emission reductions from all other sources are now excluded from the Federal Plan. *See* EPA, *Good Neighbor Plan for 2015 Ozone NAAQS Maps*, https://t.ly/zQK9L ("Good Neighbor Maps") (App'x 296-97). Moreover, EPA never analyzed the costs, efficacy, and burdens of the version of the rule it is now implementing. Nor did it ever examine the effect of the removal of 12 states on the trading program for electric generating units.

IV. Differences Between the Federal Plan and Past Federal Implementation Plans

While the Federal Plan is similar to prior federal Good Neighbor plans in some respects, it also creates a host of never-before-seen regulatory programs. As with prior plans, EPA's trading program starts by using "preset emissions budgets" for each State. 88 Fed. Reg. at 36,662. EPA claims the emissions reductions required by each statewide budget are in the amount necessary to eliminate that State's alleged significant contribution to any downwind State's inability to attain or maintain the NAAQS. *Id.* at 36,657, 36,667. But on *top* of those budgets, EPA here decided to impose "enhancements" to require that "pollution controls will be operated" even if the States would no longer contribute significantly to other States' ozone issues without such operation. *Id.* at 36,662.

For the first time in any interstate transport program, EPA also has subjected non-power generating industries to stringent emission limitations. The Federal Plan covers, among others, cement kilns and boilers in iron mills, steel mills, pulp, paper, and paperboard mills, and pipeline engines. *Id.* at 36,658.

REASONS FOR GRANTING THE APPLICATION

This Court should stay the Federal Plan, which has a legal foundation premised on the disapprovals of State plans that seven Circuits have confirmed are likely unlawful. The 11-State Federal Plan now being implemented was never analyzed by EPA nor made available for notice-and-comment rulemaking.

Under the Administrative Procedure Act, this Court—as a "reviewing court … to which a case may be taken … on application for certiorari or other writ"—"may issue all necessary and appropriate process to postpone the effective date of an agency action." 5 U.S.C. § 705; *see also* 28 U.S.C. §§ 1254, 1651, 2101; *Nken v. Mukasey*, 555 U.S. 1042 (2008). And under "well settled" principles, such "equitable relief" is appropriate here. *Lucas v. Townsend*, 486 U.S. 1301, 1304 (1988) (Kennedy, J., in chambers).

In addition, to the extent required for such relief, there is: "(1) a reasonable probability that four Justices will consider the issue sufficiently meritorious to grant certiorari; (2) a fair prospect that a majority of the Court w[ould] vote to reverse [a] judgment below [upholding the Federal Plan]; and (3) a likelihood that irreparable harm will result from the denial of a stay." *Hollingsworth v. Perry*, 558 U.S. 183, 190 (2010); *see Nken v. Holder*, 556 U.S. 418, 427-29 (2009).

This Court should stay the Federal Plan pending further review.

I. Applicants Are Likely to Succeed on the Merits in this Case, which Warrants this Court's Discretionary Review.

Given the wide-ranging impact of the Federal Plan and the faulty foundation of unlawful state plan disapprovals on which it rests, this Court would likely grant certiorari in this case and reverse any decision by the D.C. Circuit upholding the Federal Plan. The Federal Plan is an enormous federal regulation with national importance, which EPA itself estimates will cost between $8.2 billion and $13 billion. This Court has granted certiorari in several similarly important Clean Air Act cases arising over the past decade. *See, e.g.*, *West Virginia v. EPA*, 142 S. Ct. 2587 (2022); *Michigan v. EPA*, 135 S. Ct. 2699 (2015); *EME Homer*, 572 U.S. at 506.

More than just the toll on the economy, the Federal Plan also represents an unprecedented abrogation of the congressionally granted rights of States. In remarkable unanimity, seven courts of appeals have found that EPA's disapprovals of 12 State plans, which formed a crucial basis for the 23-State Federal Plan, were likely unlawful. Despite its Federal Plan being fundamentally undermined, EPA insists it remains viable. And now, this gigantically expensive rule has gone into effect in 11 States and will cause irreparable harm to States, industry, and consumers.

Accordingly, this case merits this Court's discretionary review and, for the reasons given below, Applicants are likely to succeed on the merits.

A. The Federal Plan as Promulgated No Longer Exists, and EPA Never Analyzed or Allowed Comment on the Smaller, Transformed Version.

The 23-State Federal Plan is likely to be vacated by the D.C. Circuit or by this Court because it rests on a legally faulty foundation—EPA's disapproval of State plans. Every circuit that has reviewed those disapprovals has issued stays recognizing that EPA's action was likely unlawful. *See supra* at pp. 7-8 & nn. 4, 5. While EPA has removed the 12 States that are the subject of the stays from the Federal Plan, the Federal Plan was premised on inclusion of those States. It thus cannot lawfully be implemented anywhere consistent with the Clean Air Act and the Administrative Procedure Act.

EPA never noticed, analyzed, or took comment upon the 11-State Federal Plan it is now implementing—a clear violation of all the procedures required under the Clean Air Act and the Administrative Procedure Act for notice-and-comment rulemaking. 42 U.S.C. § 7607(d)(3); 5 U.S.C. § 553. Moreover, EPA's insistence on moving forward in the remaining States regardless of this fundamental flaw is almost certain to be held arbitrary and capricious. EPA's attempt to make workable its collapsing Federal Plan by severing the inseverable—as if it would have imposed the same plan on 11 States that it would have if all 23 States were included—is unlawful and contrary to its own statements and analysis justifying its Federal Plan.

1. EPA Premised the Federal Plan on the Inclusion of all 23 States.

The administrative record clearly demonstrates that in many fundamental respects, EPA premised its Federal Plan on the inclusion of all 23 States. EPA's Federal Plan started by distributing emissions limitations among all upwind States in the Plan by assuming sources within all of those States would impose controls at the same costs. *See supra* at pp. 9-10. As this Court explained, EPA's "cost-effective" methodology assumes the same expenditure on emissions controls "applied *uniformly* to *all* regulated upwind States" at a level sufficient to achieve EPA's desired "*combined* effect" downwind. *EME Homer*, 572 U.S. at 501-02 (emphasis added); *see also* 88 Fed. Reg. at 36,741. EPA justified "[a]pplying these emissions control strategies on a *uniform* basis across *all* linked upwind states" as "an efficient and equitable solution to the problem of allocating upwind-state responsibility for the elimination of significant contribution." 88 Fed. Reg. at 36,741 (emphasis added). It then sets its emissions "budgets" for each State based on this analysis that assumed all 23 States would be included in its Federal Plan. *See EME Homer*, 572 U.S. at 501-02.

In addition to its interdependent state budgets (the "cap" in its "cap-and-trade" program), another fundamental feature of EPA's Federal Plan is its interstate emissions allowance trading program (the "trade"). *See id.*, 572 U.S. at 503 & n.10. Necessarily, EPA's analysis of the benefits and efficiencies of that trading program presumed inclusion of all 23 States in the program. 88 Fed. Reg. at 36,657. EPA itself explained the emissions trading marketplace depended on breadth because "[b]roader marketplaces generally provide greater market liquidity and therefore make trading programs better at providing … advantages" such as "cost minimization" and "operational flexibility." *Id.* at 36,766 n.295; *see also id.* at 36,760 (noting EPA was adopting a trading program "because of the inherently greater flexibility that [it] can provide"); *id.* at 36,771 (responding to commenters concerned with grid reliability by pointing to the interstate trading program). As with any market, the price of emission allowances depends heavily on the supply of those allowances, and therefore the number of States in the program. *See id.* at 36,775. Indeed, EPA recently stated that "the Plan depends on the continuing operation of 'interdependent' interstate mechanisms, like the allowance trading program, that reach beyond state or regional borders." EPA's Motion to Dismiss or Transfer Petitions for Improper Venue, *Tulsa Cement et al. v. EPA*, at 16, No. 23-9551 (10th Cir. July 20, 2023) ("EPA Motion to Dismiss or Transfer").

Moreover, EPA justified the Federal Plan based on its claimed benefits: the purported "meaningful" air quality improvements that would result "collectively" from the inclusion of all 23 States in the Federal Plan. *See* 88 Fed. Reg. at 36,683; *accord id.* at 37,648; *see also EME Homer*, 572 U.S. at 502. EPA claimed: "When the effects of these emissions reductions are assessed *collectively* …, the *cumulative* improvements in ozone levels at downwind receptors … are both measurable and meaningful…." 88 Fed. Reg. at 36,741 (emphasis added). Indeed, this cumulative analysis was EPA's basis for showing it was acting within the bounds of the Good Neighbor provision: EPA's analysis of "whether the rule achieves a full remedy to eliminate 'significant contribution' while avoiding over-control" was based on "the identified reductions" from all 23 States in the Federal Plan as "*combined and collectively analyzed* to assess their effects on downwind air quality." *Id.* at 36,719 (emphasis added); *see id.* at 36,743, 36,747-48 (listing only the "aggregate" and "collective" air quality improvements); *see also EME Homer*, 572 U.S. at 523.

As EPA describes it, its 23-State Federal Plan is one that is "interstate" and "interdependent." EPA Motion to Dismiss or Transfer at 16. EPA emphasizes that its Federal Plan is a "coordinated, 23-state program … in a long line of national-scale, multi-state federal implementation plans that have addressed interstate transport of ozone-causing pollutants through a series of integrated multi-state emissions allowance trading programs." EPA Resp. to Pet.'s Mot to Sever, Doc. #2018488, *Utah v. EPA*, No. 23-1157 (D.C. Cir. Sept. 22, 2023); *see also* EPA Opp. to Admin. Stay, Doc. #2008854, *Utah v. EPA*, No. 23-1157 at 1 (D.C. Cir. July 20, 2023) (describing the Federal Plan as a "coordinated, interstate emissions control program" covering "23 states"). The premise that the Federal Plan would include all 23 States in an interdependent program undergirded everything from EPA's cost-effectiveness analysis to its benefits determinations and from the emissions caps to the trading program.

2. The Current 11-State Federal Plan Violates the Basic Principles of the Clean Air Act and the Administrative Procedure Act.

EPA is now implementing its interdependent 23-State Federal Plan in only 11 States. It is required to do so because numerous federal courts of appeals have held that EPA likely violated the most basic requirement of the Clean Air Act by undermining the careful balance between state and federal authority that Congress prescribed. *See supra* at p. 5. Despite commenters and courts informing EPA of the Federal Plan's unlawful foundations—the disapproval of individual State plans—EPA published and is implementing it anyway in 11 States. Applicants are likely to succeed in demonstrating EPA's actions are unlawful for at least three reasons.

First, the Federal Plan violates basic requirements of the Clean Air Act and the Administrative Procedure Act by failing to provide notice and comment on an 11-State federal implementation plan rather than the 23-State plan originally contemplated. 42 U.S.C. § 7607(d)(1)(B), (3); 5 U.S.C. § 553(b), (c). The stays of the Federal Plan in 12 States have forced EPA to remove those States from its Plan, but EPA's decision to nonetheless implement an 11-State plan is unlawfully enforcing a rule EPA never proposed, received comments on, analyzed, or lawfully promulgated. As explained above, EPA analyzed only a 23-State plan, justifying many fundamental parts of that Plan on the inclusion of all 23 States. The difference is especially stark because removing 12 States with stays from the Federal Plan means nearly 90% of the power plant emissions reductions and 60% of the non-power plant emission reductions that EPA analyzed as part of its rulemaking are now excluded from the Federal Plan. *See* Good Neighbor Maps at App'x 296-97.

The 11-State plan that is currently being implemented has never been analyzed by EPA. For example, EPA never performed an 11-State analysis of: (i) cost-effective emissions controls (the basis for each State's emissions budget); (ii) the efficacy of the trading program; or (iii) the downwind air quality benefits. *See* 88 Fed. Reg. at 36,666, Table 1.C-1; EPA, Regulatory Impact Analysis for the Final Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard at 24-25, *available at* https://t.ly/x6P5l (examining various scenarios none of which involved removal of more than half the States or a State-level analysis). No one—not States, nor members of the public, nor even EPA itself—has analyzed or commented on this completely altered version of a rule that is now imposing enormous costs.

Second, the Federal Plan is arbitrary and capricious because it "entirely fail[s] to consider an important aspect of the problem…." *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983). Namely, EPA failed to appreciate that its state plan disapprovals—the necessary legal predicate for the Federal Plan—are likely unlawful and thus not in effect. The agency never considered the likely scenario that a significant number of its state plan disapprovals would be stayed or vacated, rendering large portions of the Federal Plan inoperable. Commenters alerted EPA to the unlawfulness of the state plan disapprovals, those disapprovals were challenged in a dozen states with litigants moving for stays, and now seven courts of appeals have granted those stays, confirming that those disapprovals were likely unlawful. *See supra* at pp. 7-8 nn. 4, 5. Those court-ordered stays did not make EPA's state plan disapprovals likely unlawful; they simply declared what the law always was, including when EPA finalized the Federal Plan. *See Nat'l Fuel Gas Supply Corp. v. FERC*, 59 F.3d 1281, 1289 (D.C. Cir. 1995). Indeed, three courts stayed the state plan disapprovals in five States *before* EPA published its Federal Plan in the Federal Register. *Supra* at pp. 7-8 & n.4. Yet, EPA entirely failed to reconsider its analysis based on this reality before consummating its final agency action. Despite all of the warnings and everything EPA knew before it published the Federal Plan, EPA charged forward.

This mess is one of EPA's own making. It proposed the Federal Plan before its state plan disapprovals were finalized (or, in some cases, before the disapprovals of some states' plans had even been proposed), *see supra* at p. 7, began to finalize the Federal Plan despite warnings that the state plan disapprovals were likely unlawful and court challenges to them began to mount, and published the Federal Plan in the Federal Register even after three courts of appeals started declaring its state disapprovals were likely unlawful. That is arbitrary and capricious.

Third, EPA's rulemaking makes no sense with 12 States excised and is thus arbitrary and capricious for this reason too. These 12 States are not severable from EPA's analysis and justifications for the Federal Plan; those things "cannot function sensibly without" including all 23 States that were part of EPA's uniform cost-thresholds, trading program, downwind benefits justification, and the like. *Belmont Mun. Light Dep't v. FERC*, 38 F.4th 173, 188 (D.C. Cir. 2022). EPA does not and cannot argue that "the agency would have adopted" the same plan for 11 States by, for example, imposing the exact same emissions controls on those 11 States had it known a bevy of upwind States would not also have been subject to those controls. *Am. Fuel & Petrochemical Manufacturers v. EPA*, 3 F.4th 373, 384 (D.C. Cir. 2021). EPA cannot lawfully salvage a rule in shambles by implementing the bits and pieces still left. The Federal Plan is a shell of its original self, rendering the analysis underpinning the rule incoherent and irrelevant. It will likely be vacated after full merits consideration and therefore must be stayed now.

B. Even if the Federal Plan Still Consisted of All 23 States, It Would Nonetheless Violate the Clean Air Act.

Even assuming that the Federal Plan EPA is now implementing is the one that underwent notice-and-comment rulemaking, Applicants are likely to prevail because the Plan violates the Clean Air Act and this Court's precedent. It unlawfully "over-controls" emissions and capriciously includes non-power generating industrial sources, contrary to the statutory requirements and EPA's own analysis.

1. This Court has explained that EPA cannot "over-control": it "cannot require a State to reduce its output of pollution by more than is necessary to achieve attainment in every downwind State" or by more than would be necessary for a particular state to eliminate all of its "significant[]" contributions to downwind sites. *EME Homer*, 572 U.S. at 521-22. But that is exactly what the Federal Plan is designed to do.

EPA first determined what emissions budgets are necessary to ensure compliance with the Good Neighbor provision, as it had with prior rulemakings. 88 Fed. Reg. at 36,754 (projecting emissions budgets to be a "full remedy" by the conclusion of the 2026 ozone season). Then, on top of that, EPA imposed "enhancements" for power plants to further ratchet the budgets downward—regardless of whether further ratcheting is needed to eliminate significant contribution. *See id.* at 36,764 (explaining "enhancements" are to "better sustain incentives to control emissions over time"); *id.* at 36,751 (declining to evaluate over-control after EPA's dynamic budget enhancements take effect in 2030); *see also id.* at 36,685.

For example, EPA set each State's annual emissions budgets for its cap-and-trade program at the level of emissions sufficient to eliminate significant downwind contributions. But beginning in 2030, an enhancement called "dynamic budgeting" will reduce the State's budget if a power plant shuts down or limits operation, or if a

State otherwise does not use allowances available to it. *Id.* at 36,663. In each of those scenarios, changes on the ground mean a large amount of the emissions that EPA deemed to be "contributing significantly" to downwind ozone are not occurring, making the State's contribution to downwind locations less significant or possibly insignificant. Nonetheless, dynamic budgeting would shrink the entire budget for the State, making the budgets more stringent and well-below what EPA already determined was necessary to eliminate significant contribution. That facially and systematically over-controls.

Similarly, EPA's "enhancements" require certain power plants to relinquish some of their unused allowances when they bank more than enough to comply with the cap-and-trade budgets or emit above certain amounts. *Id.* at 36,664, 36,766. EPA tacitly concedes that this is not to prevent significant contribution, but rather to "continuously incentiviz[e] sources to reduce their emissions even when they already hold sufficient emissions allowances…." *Id.* at 36,766. Because those power plants would have already created or purchased sufficient allowances to eliminate significant contribution, however, the Federal Plan facially requires more than is necessary.

2. EPA also capriciously shoe-horned other sectors of the economy into the Federal Plan in excess of its authority.

EPA completely disregarded whether the substantial costs of including those sources could justify the nearly immeasurable benefit on air quality. EPA proposed a "uniform cost" framework to determine the "amount of emissions that is in excess of the emissions control strategies that EPA has deemed cost-effective" to eliminate significant contributions. 88 Fed. Reg. at 36,676. In other words, it set a threshold ($7,500 per ton of reduction) above which control measures are too expensive to justify the purported benefit. As other Applicants explain with respect to pipeline engines, EPA then proceeded to ignore it. *See* Emergency Application for Stay of Final Agency Action During Pendency of Petitions for Review, *Kinder Morgan, Inc., et al. v. EPA* (Oct. 13, 2023).

For example, when EPA looked at cement kilns in its proposal, it wrongly assumed the kilns did not already have emissions controls for the relevant pollutants and determined they could achieve substantial reductions below the cost threshold on an industry-wide basis. *See* Portland Cement Association Comments at 9 (June 21, 2022) ("PCA Comments") (App'x 306) But three-quarters of the kilns EPA evaluated already had controls in place, so the tons of reduction would be much smaller (and therefore, the cost per ton much higher) than EPA predicted. *Id.* Despite being provided actual data on kiln emissions, *id.* at 9-10, EPA doubled down on its false assumptions in the Federal Plan. 88 Fed. Reg. at 36,826; *see also id.* at 36,739 (showing projections of reductions with what EPA falsely assumed would be "additional" controls). If EPA had simply relied on the actual, verifiable data, rather than assumptions, it would have excluded cement kilns.

EPA's treatment of the costs for the paper industry is similarly baffling. EPA concluded that it could achieve a grand total of 0.0117 parts billion in ozone reductions (recall that the standard is 70 parts per billion) by requiring boilers at pulp and paper mills to install equipment that has never been used on them in the United States. *See* American Forest & Paper Association Comments at 6 (June 21, 2022), Docket ID No. EPA-HQ-OAR-2021-0668-0516 ("AF&PA Comments") (App'x 335); EPA's Non-EGU Screening Assessment Memo at 16, Docket ID No. EPA-HQ-OAR-2021-0668-0150, Table 5, *available at* https://t.ly/pzIM6; Noe Decl. ¶12. EPA wrongly estimated that it would cost $3,800 per ton to do so. Noe Decl. ¶10. That was off by an order of magnitude; the industry calculated the average cost at $37,900 per ton. *Id.* Rather than exclude these boilers, EPA came up with a new cost estimate of $14,134 per ton, 88 Fed. Reg. at 36,740, Table V.C.2-3, and provided new excuses for exceeding the original $7,500 per ton threshold, without providing any fair notice or opportunity to comment on this new threshold. *Id.* at 36,746.

Worse still, some of Federal Plan's requirements are completely unmoored from the proposal. The Federal Plan requires steel industry reheat furnaces to have in place a plan by August 2024 to install equipment called "Low NOx Burners" and to achieve a 40% reduction in nitrogen oxide emissions from those furnaces by 2026. *Id.* at 36,879. But this requirement was not in the proposal at all. So, the steel industry had no opportunity to comment on it. Accordingly, regulated sources need to make immediate decisions in 2023 on whether to upgrade or retire furnaces and natural gas boilers in advance of judicial review of the Federal Plan. Balserak Decl. ¶¶6-8.

In short, even EPA's Federal Plan as originally envisioned was fundamentally flawed. Applicants are therefore likely to succeed on the merits for these reasons, too.

II. Absent a Stay, the Applicants and Their Members Will Suffer Substantial Irreparable Harms.

The Applicants and their members will suffer irreparable harm if the Federal Plan is not stayed. "[C]omplying with a regulation later held invalidated almost *always* produces the irreparable harm of nonrecoverable compliance costs." *Thunder Basin Coal Co. v. Reich*, 510 U.S. 200, 220-21 (1994) (Scalia, J., concurring) (emphasis in original). In *Philip Morris v. Scott*, 131 S. Ct. 1 (2010) (Scalia, J., in chambers), Justice Scalia recognized that "[i]f expenditures cannot be recouped, the resulting loss may be irreparable." *Id.* at 4. He accordingly found irreparable harm had adequately been demonstrated where the applicants showed they would irrevocably expend $270 million before the Court could even consider the claim. *Id.* Economic injuries are also irreparable when unlawful agency action deprives companies of "very significant future revenues" which will be "permanently" lost, even if the action is ultimately overturned. *In re NTE Connecticut, LLC*, 26 F.4th 980, 991 (D.C. Cir. 2022).

Applicants and their members face both kinds of irreparable harm. The Federal Plan requires Applicants and their members to reduce emissions drastically. To reach compliance in time, they will have to immediately begin the process of installing prohibitively expensive emissions controls, incurring "hundreds of millions of dollars in capital compliance and construction costs." Farah Decl. ¶12; *see also* Brown Decl. ¶36; Balserak Decl. ¶¶9-10; Maule Decl. ¶6; Piotrowski Decl. ¶5; Toso Decl. ¶34-36.

Sources that cannot feasibly install new emissions controls will be forced to buy emissions allowances from other parties, decrease their production, or cease operations altogether. Marshall Decl. at 2-3 (explaining sources may need to "reduce generating hours to meet emission restrictions" if "sufficient allowances" are not available); Balserak Decl. ¶8 (explaining sources "will need to immediately make a decision … on whether to upgrade or retire" units); Alban Decl. ¶27 (Federal Plan will "likely force many baseload generation assets to retire"); Brown Decl. ¶21 (explaining the Federal Plan will require OVEC to either transition a unit to only seasonal production or consider retirement); Toso Decl. ¶37 (PCA member has identified a real possibility it may cease operations). And because there will be both fewer emissions allowances and higher demand as a result of 12 States being removed from EPA's intended Federal Plan, utility sources will be forced to either purchase allowances at a significantly higher premium or curtail operations. Farah Decl. ¶11 (explaining a spike in demand for allowance prices in 2022 imposed an additional $50 million in operating costs for a single plant); Brown Decl. ¶20 ("OVEC can no longer rely on a viable allowance trading market … to meet future compliance obligations.").

Even setting aside the costs of the emissions controls themselves, electric generating units and industrial facilities will incur significant additional costs related to "the process of initiating engineering, design, and procurement" of controls by 2026 that "would be unnecessary" if the Federal Plan is held invalid. Balserak Decl. at 3-4; *see also* Brown Decl. ¶32 (OVEC must begin the "process immediately" and will "incur costs within the next six months"); Alban Decl. ¶24 (utilities have "very little time to develop power supply plans and environmental compliance plans"); Purvis Decl. ¶32; Farah Decl. ¶15 ("Mon Power will need to take imminent action in order to comply"); Champion Decl. ¶9 (Georgia Pacific will be required to "start contracting immediately" to comply "with the tight timeframe"); Maule Decl. ¶7; Kotara Decl. ¶5; Piotrowski Decl. ¶7; Toso Decl. ¶30.

The paper industry, in particular, will incur significant costs to design, install, and operate new controls, some of which have never been applied in that industry. Noe Decl. ¶12. The capital costs of these investments for only three units of one company range from $45 to $125 million and will impact the market competitiveness of affected mills. Champion Decl. ¶¶6-8; *see also* Kotara Decl. ¶4. The total capital cost for such units in the paper industry would be $660 million. AF&PA Comments at 2.

As noted above, some companies may cease operations at specific sources altogether. For those sources that must reduce or cease their use of coal to comply with the Federal Plan, the Plan will also drastically harm the coal mine operators that supply those sources with their fuel. Brock Decl. ¶¶15-17; Adams Decl. ¶¶10-13; Hamilton Decl. ¶¶12-14; Bridgeford Decl. ¶¶11-14.

III. The Balance of Equities and the Public Interest Favor a Stay.

"In close cases the Circuit Justice or the Court will balance the equities and weigh the relative harms to the applicant and to the respondent." *Hollingsworth*, 558 U.S. at 190. Any such balancing also favors a stay. First, a stay will not harm any other parties. EPA ignored its statutory deadline to disapprove the State plans it now proposes to replace for years. It cannot now argue a brief stay will cause sweeping public harms. *See Texas v. EPA*, No. 23-60069, Stay Order, Slip Op. at 24 (5th Cir. May 1, 2023). Despite the Federal Plan's immediate harms to Applicants, it would not actually result in any significant emission reductions for years. *See* 88 Fed. Reg.

at 36,785-86, Table VI.B.4.c-1. Nor will a stay interfere with projected future declines in nationwide ozone levels due to existing, robust ozone controls and regulations already in place.

Second, the public interest strongly supports a stay. The significant compliance costs to electricity generators that the Federal Plan will inflict may be passed on to ratepayers, including some ratepayers who will not be able to bear additional energy costs. Brown Decl. ¶45; Alban Decl. ¶24; Purvis Decl. ¶¶24, 33, 58; Farah Decl. ¶14.

In addition, if regulated companies reduce operations or stop operating altogether, communities around the country will lose jobs and tax revenue. *See, e.g.*, Fuentes Decl. ¶¶5-7; Purvis Decl. ¶¶33, 35, 58; Farah Decl. ¶10; Brock Decl. ¶15. Because the Federal Plan will require sources to reduce their reliance on the most reliable power—like coal-fired generation—it will increase grid instability and unreliability. Fuentes Decl. ¶¶5, 8; Alban Decl. ¶¶26, 28; Purvis Decl. ¶¶25, 33, 54; Brown Decl. ¶27.

In addition, electric reliability experts and grid operators have noted reliability troubles that the Federal Plan will exacerbate. *See* PJM, Energy Transition in PJM (Feb. 24, 2023) at 7, *available at* bit.ly/3YirOCr (noting the combined result of the Federal Plan and others has "the potential to result" in "significant generation retirements" in a condensed time); North American Electric Reliability Corporation, 2023 Summer Reliability Assessment Infographic (May 2023) (noting reliability concerns), *available at* bit.ly/3qa6Jh4.

Finally, EPA's disapproval of State plans is being litigated in multiple circuits, and those courts have issued multiple stays. EPA's decision to forge ahead anyway threatens an impossible tangle of regulatory obligations on sources, especially since the Federal Plan was designed to work with 23, not 11 States. A stay by this Court will allow orderly review of EPA's unlawful actions.

CONCLUSION

For the foregoing reasons, Applicants respectfully request an immediate stay of EPA's Federal Plan.

Dated: October 13, 2023

Respectfully submitted,

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DECLARATION OF AMERICAN IRON AND STEEL INSTITUTE

Paul Balserak declares, pursuant to 28 U.S.C. § 1746, as follows:

1. I am Vice President for Environment of the American Iron and Steel Institute ("AISI"). Prior to my current role, I served as the deputy director of the regulatory policy division of in the Administrator's Office at the U.S. Environmental Protection Agency and in several other positions at the agency for over 26 years. I hold a Master of Science in Biology from George Mason University and a Bachelor of Science in Civil Engineering from Virginia Polytechnic Institute and State University.

2. AISI serves as the voice of the American steel industry with membership comprised of steel producing companies, including integrated and electric arc furnace steelmakers, and associate members who are suppliers to or customers of the steel industry. The steel industry's steel products serve a key role as a material of choice for infrastructure improvements and other applications, important to our nation.

3. AISI is a member of the Midwest Ozone Group ("MOG"). MOG is an affiliation of companies and associations that draws upon its collective resources to seek solutions to the development of legally and technically sound air quality programs that may impact on their facilities, their employees, their communities, their contractors, and the consumers of their products.

4. I am providing this declaration in support of a stay of the United States Environmental Protection Agency's ("EPA") Federal Implementation Plan (FIP) regulation known as the Good Neighbor Plan for the 2015 Ozone National Ambient

Air Quality Standards ("Good Neighbor FIP"), published in the Federal Register on June 5, 2023 at 88 Fed. Reg. 36654. This regulation will have immediate and significant irreparable impacts on the operations of facilities owned and operated by members of the AISI if a stay is not granted and compliance dates are not similarly stayed pending a final judicial decision on the merits. This declaration is based on my personal knowledge of facts and analysis conducted by AISI.

5. AISI membership is impacted by the regulated industrial source sector for Iron and Steel Mills addressed by the Good Neighbor FIP. Iron and Steel Mills located and operated within states that are located in Alabama, Arizona, Arkansas, Colorado, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Tennessee, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin. Disapproval of a SIP is a legal prerequisite for EPA to impose a FIP. To date, we have operations 13 states that have not been granted or have not sought a stay of the SIP disapprovals as follows: Illinois, Indiana, Michigan, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Utah, Virginia, Washington, West Virginia, and Wisconsin.

6. The Good Neighbor FIP implements controls on reheat furnaces in the form of Low NOx Burners, technology that was not proposed in the rule and therefore not assessed by AISI regulated members relative to cost effectiveness prior to promulgation and implementation. Reheat furnace 40% NOx reductions plans must be

in place by August 2024 allowing inadequate time for engineering, procurement, installation and operation or for EPA approval of such.

7. The Good Neighbor FIP arbitrarily requires NOx CEMs on boilers rated at 250 MMBtu/hr or greater unless initial performance test indicates the unit's emission rate is 70% or less below the applicable NOx limits of 0.08 lb/MMBtu which percentage is established resulting in arbitrary and capricious over controls.

8. If the Good Neighbor FIP is not stayed and proceeds forward on the schedule that EPA intends, the FIP will require AISI industrial regulated boilers and furnaces to comply with unit-specific NOx limits during the ozone season (from May l – September 30 annually) starting in 2026, accordingly regulated sources will need to immediately make a decision in 2023 on whether to upgrade or retire reheat furnaces and natural gas fired boilers, in advance of a decision by the Court on the merits of the FIP.

6. The preliminarily estimated capital costs to achieve the 40% reduction required will be at least $3 to 5 million dollars per reheat furnace as illustrated by recent Reasonably Available Control Technology analyses.

7. Without a stay, and with the tight timeframe established in the FIP, which requires compliance with the new limits by May 2026, AISI members have been forced to begin the process of initiating engineering, design and procurement of the equipment projected to be required as described above, in order for the furnace or boiler modifications or shutdowns to be completed in time to comply with the new

requirements by May 2026. All of this capital, time, and other resources would be unnecessary if the Good Neighbor FIP is ultimately determined on the merits to be unlawful as petitioners state in their petition(s) for review.

8. For the reasons set forth above, AISI supports a stay of the Good Neighbor FIP to avoid immediate, significant, and irreparable harm pending a final decision by the Court on the merits regarding its lawfulness under applicable statutes.

I, Paul Balserak, declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct. Executed on July 19, 2023.

Paul Balserak
Vice President, Environment
American Iron and Steel Institute

UNITED STATES STEEL CORPORTATION

COMMENTS ON

PROPOSED FEDERAL IMPLEMENTATION PLAN ADDRESSING REGIONAL OZONE TRANSPORT FOR THE 2015 8-HOUR NAAQS.

Docket ID No. EPA-HQ-OAR-2021-0668

87 Federal Register 20,036 (April 6, 2022)

JUNE 21, 2022

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Exhibit E:

USS SIP Disapproval Comment

Exhibit F:

USS FIP Comment Extension

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June 21, 2022

ATTN: Docket ID No. EPA-HQ-OAR-2021-0668

Administrator Michael Regan
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Docket ID No. EPA-HQ-OAR-2021-0668
U.S. Environmental Protection Agency

Submitted via Federal eRulemaking Portal (Regulations.gov)

RE: Comments of United States Steel Corporation ("U. S. Steel") on the "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Primary Ozone National Ambient Air Quality Standard," Docket No. EPA-HQ-OAR-2021-0668, 87 Fed. Reg. 20,036 (April 6, 2022) ("Proposed Rule").

Dear Administrator Regan,

United States Steel Corporation ("U. S. Steel") on behalf of the company and all our subsidiaries[1] and affiliates appreciates the opportunity to submit the following comments to the United States Environmental Protection Agency ("EPA") regarding the proposed "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Primary Ozone National Ambient Air Quality Standard" Docket No. EPA-HQ-OAR-2021-0668. *Federal Register* 87 Fed. Reg. 20,036 (April 6, 2022) ("Proposed Rule"). The Proposed Rule creates Ozone NOx Standards related to the Clean Air Act Good Neighbor provisions. The comment period for the Notice closes on June 21, 2022. U.S. Steel provides the following general and specific comments below related to the Proposed Rule.

[1] Big River Steel, LLC (BRS) and Exploratory Ventures, LLC (EV) are both wholly owned subsidiaries of U. S. Steel. BRS is an operating scrap to steel products facility in Osceola, Arkansas and EV is a scrap to steel products facility under construction in Osceola, Arkansas. These are only two of the U. S. Steel subsidiaries and facilities and these comments apply to all subsidiaries and locations however some comments may directly reference these locations.

INTRODUCTION

The Proposed Rule's treatment of non-EGUs, including the iron and steel industry, sharply departs from EPA practice and court interpretations of the Good Neighbor provision of the Clean Air Act (CAA). As more fully detailed herein, EPA treats EGUs and non-EGU sources (including the iron and steel industry) in fundamentally different ways, many of which directly conflict with past EPA determinations and court decisions without reasonable explanations for departure, including but not limited to:

- Setting statewide budget limits for EGUs, while instead subjecting iron and steel units to unit specific command and control limits without any evaluation of how the proposed limits relate to the amount of statewide reductions needed to eliminate a state's alleged substantial contribution;
- Allowing emissions trading for EGUs, but not for non-EGUs;
- Accounting for feasibility in evaluating applicability of EGU provisions to types of EGUs (e.g., waste incinerators) and which States to subject to the EGU provisions (e.g., California), but not performing any feasibility analysis, much less facility or unit specific feasibility analysis, for the iron and steel industry (indeed, ignoring all prior determinations, including recent determinations that post combustion controls[2] are not feasible for EAFs and other emission units the Proposed Rule would cover in the iron and steel industry);
- Modeling impacts and cost effectiveness of controls for EGUs as a single industry, but grouping all other covered industries together as "non-EGUs" for a single cost effectiveness analysis, without evaluating what level of controls would be cost effective for each of the separate industries the Proposed Rule would cover;
- Modeling the effect of multiple cost thresholds for EGUs as an industry ($1,600, $1,800, and $11,000) to evaluate whether lower cost thresholds could achieve sufficient reductions, but only modeling a single cost threshold ($7,500) for all non-EGUs without any consideration of whether a lower cost threshold for some or all such industries could still result in sufficient emission reductions to satisfy Good Neighbor requirements.

When determining what non-EGUs to regulate under the Proposed Rule, EPA also did not correctly follow the "4-step interstate transport framework" used by EPA in prior rulemakings and approved by the Supreme Court. Under that approach, EPA, after identifying nonattainment and maintenance receptors (step 1), and screening out any state not significantly contributing to any linked receptor (step 2), was then supposed to "(3) for states linked to downwind air quality

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[2] The term "post-combustion controls" is used herein only for convenience and consistency with the way in which EPA describes emission controls such as SCR in the Proposed Rule. As described in more detail herein, some of the furnaces covered by the Proposed Rule, most notably an EAF, is not a combustion process, such that any downstream emission controls on an EAF would not technically be "post-combustion."

problems, identify [] upwind emissions that significantly contribute to downwind nonattainment or interfere with downwind maintenance of the NAAQS; and (4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind areas, implement[] the necessary emissions reductions through enforceable measures." But the EPA did not follow this approach in the Proposed Rule. Rather than evaluate the upwind emissions that actually contribute to each screened-in state's linked nonattainment or maintenance receptors, EPA instead just (1) identified industries nationwide that contributed relatively more than other industries, and (2) automatically mandated limits directly on all such industries in each screened-in state, skipping any finding that the industries (let alone specific sources) evaluated on a nationwide basis actually contributed to nonattainment or interfered in maintenance at the linked receptors for each particular state.

The resulting Proposed Rule imposes limits on NOx emissions that EPA's own analysis acknowledges have never been demonstrated in the iron and steel industry and cannot be met by any technology currently available for use in the iron and steel industry. Many of the technologies proposed by EPA to control NOx (e.g., SCR, SNCR) are not technically feasible for the emission units included under the Proposed Rule. And even if technology used in wholly dissimilar industrial processes (e.g. coal-fired power plants and boilers) were able to be implemented, the costs would be significantly higher than the thresholds EPA relied upon for screening out available control technologies. EPA also assumes that low NOx burners are an available technology for certain emission units to reduce NOx emissions, completely ignoring the fact that many of these units already incorporate low NOx burner technology. Associated production downtimes also would have severe economic consequences for the industry. Furthermore, it is without question that efforts to adapt these technologies to the iron and steel industry would increase emissions of other pollutants and require re-engineering and modifications to not only the steel making process, but also existing air pollution control equipment. Simply put, the addition of ancillary equipment to address flue gas characteristics and the batch nature of the steelmaking process, among other challenges, would necessarily drive up costs and have both upstream and downstream impacts that would not have been accounted for in the original equipment design specifications.

The Proposed Rule also makes assumptions regarding equipment availability and constructability that cannot be reconciled with present and future supply chain considerations and threatens to hamstring the economy and national security with extended downtime or closures and resultant shortages of domestic iron and steel supply.

To justify all the above, the Proposed Rule relies on arbitrary modeling using result-oriented assumptions containing significant errors and omissions, incorrect interpretations of the CAA and legal precedents addressing pollution transport. In short, the Proposed Rule attempts to go well beyond EPA's authority under the CAA. In so doing EPA risks legal challenges to any final rule in the same form as the Proposed Rule that will restrict EPA's discretion in future rulemakings. And because the Supreme Court allows as applied challenges to rulemakings effectuating the Good Neighbor clause of the CAA, EPA's decision to make the Proposed Rule apply on a unit specific basis directly to facilities means that EPA will open the door to as-applied challenges as every covered facility will have the ability to challenge the applicability of the Proposed Rule's limits as applied to that facility, likely jettisoning the uniformity that EPA purports to seek in the Proposed Rule and stringing out any rulemaking in constant challenges.

GENERAL COMMENTS PERTAINING TO THE PROPOSED RULE

I. The Proposed Rule's Attempt to Impose Unit Specific Emission Limits Is Unlawful, Arbitrary, and Not Supported By the Record.

A. EPA Has Identified No Legal Basis for Imposing Emission Unit Specific Limits on Any of the Individual Non-EGU Emission Units the Proposed Rule Purports to Regulate.

The provision of the CAA on which EPA bases this entire regulatory undertaking (a/k/a the "Good Neighbor provision" to the CAA) only grants authority to:

> "prohibit[ ] . . . 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 such national primary or secondary ambient air quality standard"[3]

Thus, when enacting a FIP to satisfy this provision, EPA only has authority to regulate a "source" or "type of emissions activity" if EPA demonstrates that the specific "source" or "type of emissions activity" it proposes to subject to such regulation is actually contributing significantly to nonattainment or interference with maintenance status in a state other than that in which the "source" or "type of emissions activity" is located.

This is the first time EPA has attempted to impose facility-specific emission limits under a "one-size fits all" Federal Implementation Plan based upon the Good Neighbor provision of the CAA. Accordingly, for EPA to have authority to do so under the Good Neighbor provision, EPA must demonstrate that the "source" EPA is prohibiting from emitting above the Proposed Rule's NOx limits is contributing significantly to downwind nonattainment or contributing significantly to downwind maintenance issues. But EPA fails to provide any basis for finding any U. S. Steel facility to contribute significantly to any nonattainment or interference with maintenance.

First, EPA does not define any threshold to evaluate whether a given source's contribution constitutes a significant contribution to downwind linked receptors for purposes of the Good Neighbor provision.[4] Instead, EPA sweeps in states based on a statewide significance threshold of 0.7ppb, identifies industries that on a nationwide basis contribute to downwind nonattainment or

[3] 42 U.S. Code § 7410(a)(2)(D)(i)(I).

[4] As discussed in more detail in another comment below, EPA has in fact established a facility specific significance threshold of 1ppb (i.e., the Ozone SIL) based on an actual statistical analysis of what contribution is capable of showing any modeled effect beyond mere background variation, but the Proposed Rule at no point acknowledges this threshold or prior statistical analysis.

maintenance receptors using a 0.01ppb significance threshold[5], then skips to applying the Proposed Rule's limits to all facilities in all such industries in all covered states without any evaluation of the statutory mandate to consider whether the specific covered "source or other type of emissions activity" will "contribute significantly to nonattainment." Failure to even set a threshold to evaluate source-level contribution significance constitutes a failure to attempt the evaluation required under the statute if EPA wishes to set source-specific emission limits.

Second, the Proposed Rule neglects to perform any source-specific impact analysis to evaluate the impact (or lack thereof) that the specific sources EPA proposes to subject to NOx limits have on any of the identified nonattainment and maintenance receptors. And this failure is not for lack of capacity. The CAMx model EPA relied on for evaluating nonattainment and maintenance receptors has the capability to tag source-level and/or industry-level contributions. As EPA notes, CAMx "employs enhanced source apportionment techniques that track the formation and transport of ozone from specific emissions sources and calculates the contribution of sources and precursors to ozone for individual receptor locations."[6] But the Proposed Rule acknowledges that EPA ignored facility level impacts on downwind-state ozone concentrations, and instead, when using CAMx, only "performed nationwide, state level ozone source apportionment modeling."[7] This failure to evaluate the significance of source specific impacts means that EPA has failed to demonstrate that U. S. Steel facilities it proposes to regulate are in fact linked to any nonattainment or maintenance receptor so as to permit emission reductions under the Good Neighbor provision of the CAA.

To be sure, EPA has not always evaluated source specific impacts on downwind receptors in other states in its prior rulemakings, but that is because those prior rulemakings were fundamentally different than the Proposed Rule. For instance, under the ozone transport rule evaluated by the Supreme Court in *EPA v. EME Homer City Generation, L.P.* 572 U.S. 489 (2014), EPA did not attempt to impose source specific controls or emission limits, but instead created an annual emission "budget" for each state that EPA concluded was contributing significantly to downwind nonattainment and maintenance issues, and then set up an interstate emission trading system within such state allowing covered sources to allocate the emissions and any needed reductions among themselves through purchase and sale of allowances.[8] Under a regulatory program set up in that manner, it may have been rational to impose an aggregated statewide emission limit for NOx from EGUs based on similarities in the sources and a finding at the same

[5] See e.g., Proposed Rule at 20,083 n. 164 (screening the significance of industry contributions using either 0.1ppb at at least one nonattainment or maintenance receptor, or 0.01ppb at at least ten such receptors, but nowhere setting a facility specific significance screening threshold).

[6] Proposed rule at 20,070.

[7] Proposed rule at 20,070.

[8] See 76 Fed. Reg. 48,208; see also EPA, "Fact Sheet: The Cross-State Air Pollution Rule: Reducing the Interstate Transport of Fine Particulate Matter and Ozone" available at https://www.epa.gov/sites/default/files/2016-09/documents/csaprfactsheet.pdf ("The final Cross-State Air Pollution Rule allows sources to trade emissions allowances with other sources within the same program (e.g., ozone season NOX) in the same or different states, while firmly constraining any emissions shifting that may occur by requiring a strict emission ceiling in each state").

level of generality that a state's statewide emissions in the aggregate significantly contributed to downwind nonattainment, and that EGUs were the primary driver (i.e., treating statewide EGU emissions as the "emissions activity" which EPA could "prohibit . . . amounts which will . . . contribute significantly to nonattainment").

Instead, EPA proposes for the first time to use the Good Neighbor provision to impose command-and-control limits at the individual facility level without any justification that the facility (or even the industrial section in the state that it is part of) contributes significantly to downstream nonattainment or maintenance issues. It is one thing for EPA to tell a state that its contribution to nonattainment/maintenance problems in another state is a certain level and then allow a state or the sources therein to allocate reductions needed among themselves to achieve the statewide reductions needed; it is quite another thing to impose specific emission limits directly on a state's sources without any further source level analysis. If EPA wishes to treat individual emission units as the granular level of "source or other emissions activity" from which to "prohibit . . . amounts which will . . . contribute significantly to nonattainment," it must necessarily show that such units "contribute significantly to nonattainment." And EPA has not attempted to do so with respect to any of the non-EGU emission units in the Proposed Rule, let alone for the emission units at U. S. Steel facilities.

B. The Analyses Included in the Record Cannot Support the Source-Specific and State-Specific Impact Findings Required by the Clean Air Act.

EPA has not adequately demonstrated that the individual or category of sources it proposes to regulate under the proposed FIP cause or interfere with ozone attainment or maintenance in downwind states, but instead uses grossly inaccurate assumptions in its analysis and modeling rendering the entire FIP fatally flawed.

The 4-step framework as applied in the Proposed Rule identifies no sources or emissions activities in one state that significantly contribute to downwind air quality problems in another state (as the Good Neighbor provision of the CAA requires). Even for states that are contributing to nonattainment or interfering with maintenance, EPA has established no data to support which non-EGU emission sources within the state are "potentially controllable," would "have the greatest ppb impact on downwind air quality" or be "make meaningful air quality improvements at the downwind receptors at a marginal cost threshold" as EPA's own interpretation of the Clean Air Act dictates.[9] Without this information, EPA's FIP is arbitrary and capricious. *State Farm*, 463 U.S. at 43 (an agency rule is arbitrary and capricious if the agency has "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").

Clean Air Act § 110(a)(2)(D) requires SIPs to contain adequate provisions to prevent "any source or other type of emissions activity within the State" that contribute significantly to NAAQS

[9] Screening Assessment at 2.

nonattainment in another state or interference with maintenance. There has been no attempt to gather or model the source-specific data needed to determine what sources, if any, should be subject to regulation to address interstate transport of NOx. For the Proposed Rule, EPA has conducted a Non-EGU "Screening Assessment"[10] to identify costs and controls, but EPA itself acknowledges that this screening assessment "is not intended to be, nor take the place of, a unit-specific detailed engineering analysis that fully evaluates the feasibility of retrofits for the emissions units, potential controls, and related costs."[11]

EPA has never used such modeling and estimation to impose unit-level emission limits. While EPA points to the screening assessment is used in CSAPR, and which was affirmed by the Supreme Court in *EPA v. EME Homer City Generation, LP*, 572 U.S. 489 (2014), there EPA was allocating state-level emission budgets and was based on "complex modeling to establish the combined effect the upwind reductions projected at each cost threshold would have on air quality in downwind States." *Id.* at 1596.

The record lacks the data needed to impose source-specific emission limits, and EPA has made no effort to develop similar source-specific modeling for non-EGUs. To the contrary, EPA's assessment, while starting with state-specific modeling to identify "linked" states, then proceeds to ignore any state-specific distinctions in evaluating the emission sources that should be subject to regulation. Specifically, after EPA identified "linkages" from a state to a downwind receptor based on as little as a 1% modeled impact on the design value, the Screening Assessment identifies industries that, without regard to those same state linkages, had over an arbitrarily set threshold of either 0.1 ppb impact on a single receptor or as low as a 0.01 ppb impact on at least 10 receptors.[12] The Proposed Rule then, without any technical or legal basis, assumes that, for those industries, every source within the same industry code has a significant contribution or interferes with maintenance and thus is subject to regulation.

Compounding this generalization, the Proposed Rule then assumes that the same controls and the same efficiency, can be achieved at all of these sources, using the same technology, and at the same cost, with no consideration of the size, age, past performance, or any other individual data from any single facility or emission unit.

While EPA could support industry-wide modeling of EGUs as a sufficient basis to impose state NOx budgets in *EME Homer*, the Proposed Rule's attempt to impose source- and emission unit-specific emission limits based on nothing more than generalized assumptions of what various industries that happen to be located in at least one "linked" state is untethered from any attempt to reduce significant contribution to nonattainment or interference with maintenance of the NAAQS and is patently insufficient. EPA cannot impose source and unit-specific emission requirements without first confirming that it screening assumption hold up when applied to the actual states, sources, and emission units that will be subject to regulation. Otherwise, EPA has "entirely failed

[10] Proposed Rule Non-EGU Screening Assessment.

[11] Non-EGU Screening Assessment at 7.

[12] *Id.*

to consider an important aspect of the problem" and "offered an explanation for its decision that runs counter to the evidence before the agency." *State Farm*, 463 U.S. at 43.

C. EPA's Sweeping Pollution Control Generalizations and Assumptions are Unproven and Inaccurate and Cannot Support the Proposed Rule' Emission Limits.

EPA cannot shift its burden to the states and affected sources to prove that its strategy is technologically and/or economically infeasible for each unique source that EPA proposes to regulate by the FIP. Rather, it is EPA's duty to provide "the factual data on which the proposed rule is based" and "the methodology used in obtaining the data and in analyzing the data." 42 U.S.C. § 7607(d)(3).

EPA's record for the Proposed Rule does not support the emissions controls or limits in the Proposed Rule, and in many cases, it contradicts the conclusions in the Proposed Rule. For example, while the Proposed Rule states that the "types of emissions control technologies on which the EPA proposes to base the emissions limitations that would take effect for the 2026 ozone season … generally are intended to be consistent with the scope and stringency of RACT requirements for existing major sources of NO_X" 87 Fed. Reg. at 20,101-102, the emission limits EPA proposes for the iron and steel industry assume, without support that emissions reductions of 25% to 50% can be achieved beyond recently-determined emission limits, including Ohio RACT limits for blast furnaces and reheat furnaces. *Id.* at 20,145, Table VII.C-3. Other limits are based on achieving similar reductions beyond recently established Best Available Control Technology ("BACT") determinations. *See id.*[13][14] The Proposed Rule not only leaves unanswered why emissions are capable of being reduced 40% from a BACT determination made last year, but also how such a limit can be imposed not only on new sources, but on existing sources as well. When the results of EPA's generalized assumptions are emissions limits that radically depart from EPA's own purported basis for establishing them, the adequacy of EPA's data and rationale for the Proposed Rule must be called into question.

EPA's proposed emission limits are also based on unsupported assumptions that pollution controls that have never been demonstrated in the iron and steel industry are feasible and effective—so effective that they will now result in substantial (40%-50%) reductions in emissions beyond current best-performing sources. As just one example, EPA has assumed that selective catalytic reduction ("SCR") is broadly available to reduce emissions from numerous sources,

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[13] The Proposed Rule's emission limit for Ladle/tundish Preheaters is based on an assumed 40% reduction from Nucor Kankakee's BACT permit limit, which was issued in 2021. 87 Fed. Reg. 20,145, Table VII.C-3.

[14] Also, U.S. Steel's BRS facility underwent PSD review in 2013 and the new EV facility underwent PSD review in 2021. BACT analyses were submitted with both applications. EPA provided comments on the draft BRS permit in 2013 but did not comment on the 2021 application. In both instances, the application of SCR, NSCR, and other post-combustion controls for EAFs and other units at the facility was eliminated from consideration because the technology is not technically feasible. See e.g., BACT Analysis in support of the U.S. Steel's BRS facility Air Permit Application for Permit 2445-AOP-R0, dated Oct. 11, 2021. Other PSD permits issued to EAFs in recent years, all subject to review and comment by USEPA, reach similar conclusions.

including blast furnaces and basic oxygen furnaces, and coke ovens, to reduce emissions by as much as 50% from currently permitted limits, along or in combination with low-NOx burners. There is nothing in the record to show that SCR has been installed on any of these emission sources, let alone that doing so would result in the emission reductions EPA projects. The only reference appears to be a 2017 article from the Arid Zone Journal of Engineering, Technology and Environment stating that "[t]he combination of low NOX burner (LNB) and Selective catalytic reduction (SCR) is capable of reducing emission for up to 90% and above."[15] The paper does not indicate that this is based on any real-world application, however, and cites only studies of the use of SCR for other sources. EPA's own 2020 assessment for the 2008 Revised CSAPR rule did not consider SCR for the primary metals manufacturing industry.[16] As AISI has also already explained in comments on CSAPR, low-NOx burners were also recently eliminated as a control option for blast furnace stoves fueled primarily by blast furnace gas.[17] Yet EPA proposes to achieve 40-50% reductions at blast furnaces using "burner replacement" for these same stoves.[18]

Similarly, for Taconite Kilns, EPA proposes to assume that low-NOx burners will result in a reduction of 40% of NOx emissions.[19] There is nothing in the record to support this conclusion.

It is EPA's obligation to "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'" *State Farm*, 463 U.S. at 43; *see also* 42 U.S.C. § 7607(d)(3) (the statement of basis and purpose must include "the factual data on which the proposed rule is based," "the methodology used in obtaining the data and in analyzing the data," and "the major legal interpretations and policy considerations underlying the proposed rule"). Nonetheless, U. S. Steel has, in the time allowed, identified several inaccuracies and improper assumptions in the feasibility and effectiveness of pollution control equipment for the iron and steel industries, and has documented those findings in the attached reports found in Exhibits A-D.

D. EPA Cannot Proceed to a Final Rule on this Record, Because the Proposed Rule Is Based Upon Many Data Errors, Data Gaps, and Incorrect Assumptions, Which Leave the Rule Insufficiently Supported.

The Proposed Rule is based on a set of vague, nation-wide assumptions about the NOx emissions generated by regulated industries, the relative contributions to downwind receptors, the emissions controls that are available to reduce NOx, the effectiveness of these controls, and cost of installation and operation, and the time required to install and operate them. These broad assumptions are generally not to be found in the record. Where U. S. Steel has painstakingly

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[15] EPA-HQ-OAR-2021-0668-0050.

[16] EPA-HQ-OAR-2020-0272.

[17] AISI Revised CSAPR Comments at 4.

[18] 87 Fed. Reg. 20,1045, Table VII.C-3.

[19] 87 Fed. Reg. 20,182.

sought to reconstruct EPA's analysis, the results indicate numerous errors and unwarranted assumptions.

U. S. Steel has endeavored to identify as many of these issues as it can in the limited time allowed and has documented these findings in the detailed reports prepared by Woodward and Curran, Black and Veatch, Trinity Consultants and Barr attached with these comments as Exhibits A - D. Prior comments have also identified numerous errors in EPA's emissions data. As U. S. Steel noted in its comments on the SIP denial rule, the emission estimates from other sources, including those in Arkansas, Illinois, Indiana, Ohio and Michigan – and in particular, emissions from the iron and steel sources in those states, are overstated and are inconsistent with prior state submittals. U. S. Steel SIP Comments are attached as Exhibits E & F. The Midwest Ozone Group has noted that numerous exceptional events have been improperly factored into the modeling used by EPA in the Proposed Rule.[20] Lake Michigan Air Directors Consortium (LADCO) has performed a detailed Source Classification Code ("SCC") based analysis of EPA's 2016v2 emissions modeling platform. In doing so, it found EPA's projected emission rates "are not consistent either with real-world emissions trends or regional emissions projection information."[21] The State of Minnesota similarly submitted a list of sources that it believes have incorrect future year projection rates.[22]

More fundamentally, however, EPA cannot proceed with a rule based upon many errors and incorrect assumptions. In order to avoid arbitrary and capricious rulemaking, "the agency must examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'" *Motor Vehicle Mfrs. Assn. of United States, Inc. v. State Farm Mut. Automobile Ins. Co.*, 463 U.S. 29, 43 (1983) (*quoting Burlington Truck Lines, Inc. v. United States*, 371 U. S. 156, 168 (1962). An agency action is 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." *Id.* Here, the rationale provided by the agency is oftentimes completely unsupported by the record. At other times, it is implausible, if not contradicted by the record.

Even if EPA were to reject the state-specific evaluations contained in the numerous SIPs before the agency, a federal implementation plan must be based on an adequate understanding of the regulated emission sources, available controls, and their costs and effectiveness. The rulemaking procedures at section 307(d) of the CAA specifically require that a proposed rulemaking must "include a summary of—(A) the factual data on which the proposed rule is based; (B) the methodology used in obtaining the data and in analyzing the data; and (C) the major legal interpretations and policy considerations underlying the proposed rule" and "All data, information,

[20] Midwest Ozone Group SIP Denial Comments at 38-53.

[21] LADCO Minnesota SIP Denial Comments at 2.

[22] *Id* citing LADCO_EPA2016v2_Projections_Comments.xlsx.

and documents referred to in this paragraph on which the proposed rule relies shall be included in the docket on the date of publication of the proposed rule."[23] Furthermore, any final "promulgated rule may not be based (in part or whole) on any information or data which has not been placed in the docket as of the date of such promulgation."[24] Relatedly, EPA has "an initial burden of promulgating and explaining a non-arbitrary, non-capricious rule."[25] The many errors and incorrect assumptions and the many ways explained throughout these comments that the Proposed Rule is not grounded in or adequately related to the modeling and data actually in the regulatory docket demonstrate that the record is simply insufficient to proceed with a final FIP.

II. EPA's Proposed Control Limits Go Beyond Any Level of Control Imposed by EPA, and Conflicts With Prior EPA Determinations.

EPA makes the assertion that the limits imposed by the Proposed Rule on non-EGUs "generally are intended to be consistent with the scope and stringency of RACT."[26] But this stated goal is inconsistent with the approach EPA actually took to setting the limits, and thus in violation of EPA's obligation to promulgate internally consistent rules.[27] In fact, for most (but not all)[28] units, EPA specifically considered RACT limits specified by states, then expressly rejected setting levels consistent with RACT, instead going on to propose limits up to a staggering 50% below the corresponding RACT limits considered.[29] These resulting proposed limits are also stricter than BACT, and inconsistent with recent BACT evaluations, which EPA had opportunity to comment on, which have ruled out SCR, NSCR, and other post-EAF NOx controls as not technically feasible for EAFs.[30] And the limits are even stricter than LAER, given that EPA can identify no new or existing facility nationwide in the industry that has demonstrated these limits in practice, and has identified no grounds for concluding that they may be feasible on an EAF.[31]

[23] 42 U.S.C. § 6707

[24] Id.

[25] *National Lime Ass'n v. E. P. A.*, 627 F.2d 416, 433 (D.C. Cir. 1980)

[26] Proposed Rule at 20,101-02.

[27] *Hsiao v. Stewar*t, 527 F. Supp. 3d 1237, 1252 (D. Haw. 2021), quoting *Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134, 1141 (9th Cir. 2015) ("[A]n internally inconsistent analysis is arbitrary and capricious.").

[28] Non-EGU Sectors TSD at 42 (considering RACT for blast furnaces, reheat furnaces, ladle preheaters, annealing and galvanizing furnaces, but not for EAFs).

[29] See e.g. Proposed Rule at 20145 identifying Ohio RACT for blast furnaces at 0.06 lb, then setting a proposed limit at half that level.

[30] See e.g., BACT Analysis in support of the U.S. Steel's BRS facility Air Permit Application for Permit 2445-AOP-R0, dated Oct. 11, 2021.

[31] Notably, although EPA claims to identify an annealing furnace that successfully installed an SCR, EPA does not use that facility as a basis for the emission limits proposed for Annealing Furnaces, further calling into question whether the limits proposed by EPA are even possible in practice. And even if some type of annealing furnace ever installed an SCR, the concept of the application of an SCR on all annealing furnaces could not be justified, for instance some of the annealing furnaces at the U. S. Steel's BRS facility are small units that emit less than 6 tpy and run only intermittently such that they are not even stacked and thus neither CEMS not SCR would be possible to connect.

Furthermore, although EPA requests comment on the appropriateness of simply requiring RACT in states subject to the Proposed Rule,[32] EPA does not claim to have even attempted to model whether RACT might be sufficient to bring any given state's linked downwind receptors into attainment. Instead, EPA states that it "focuses on obtaining emissions reductions from non-EGU units that were quantitatively determined to have the most significant impacts on air quality improvements at the downwind nonattainment and maintenance receptors." [33]

But critically, as explained in more detail throughout these comments, EPA's modeling used to demonstrate statewide emission reductions necessary to reduce downwind emissions to acceptable levels was not based on the limits included in the Proposed Rule. [34] Instead, what EPA actually modeled was as follows: "We re-ran CoST with known controls, the CMDB, and the 2019 emissions inventory. We specified CoST to allow replacing an existing control if a replacement control is estimated to be >10 percent more effective than the existing control. We did not replace an existing control if the 2019 emissions inventory indicated the presence of that control, even if the CMDB reflects a greater control efficiency for that control."[35] Notably, the output tables for this modeling show no reductions required at any EAF, and SCR only being added at certain BOF and Blast Furnaces and boilers.[36] Accordingly, to the extent that the modeling EPA actually performed shows that Good Neighbor provisions are satisfied with less stringent emission reductions, and without any reductions from a single U. S. Steel facility, EPA's choice to nevertheless go further than supported by its modeling and impose the draconian limits more stringent than RACT, BACT, or even LAER necessarily constitutes arbitrary and capricious overcontrol.

Finally, and independently, regardless of the rationality of requiring upwind states to meet RACT, it is certainly unreasonable, unlawful, and inconsistent with both EPA's past practice and court precedent interpreting the Good Neighbor provision to subject upwind states to emission limits that are stricter than the RACT limits imposed in the downwind states. After all, as EPA acknowledged when setting out the prior Good Neighbor framework upheld by the Supreme Court in *EPA v. EME Homer*, "Section 110(a)(2)(D)(i)(I) only requires the elimination of emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in other states; it does not shift to upwind states the responsibility for ensuring that all areas in other states attain the NAAQS."[37] Likewise, the D.C. Circuit's decision in *Wisconsin v. EPA* calls for aligning

[32] Proposed Rule at 20,097.

[33] Proposed Rule at 20,097.

[34] See Supra at section titled "EPA's Modeling Significantly Underestimates Reductions Associated with the Proposed Rule".

[35] Non-EGU Screening Assessment at 8.

[36] Non-EGU Screening Assessment at Table 6; see also excel file in regulatory docket titled "Screening Assessment Non-EGU Facility and Emission Unit Limits List".

[37] "Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals" 76 Fed. Reg. 48,208, 48,210 (August 8, 2011).

upwind and downwind requirements to treat them consistently to the degree possible. Accordingly, whatever requirements are placed on upwind industry should not be more stringent than those applicable to industries subject to RACT due to actually being in a nonattainment area; it would be irrational, arbitrary, and capricious, when considering impacts to the same nonattainment or maintenance receptor, to force a source far away to enact stricter limits than a source actually in or next door to the nonattainment area.[38]

III. EPA Fails to Demonstrate that the Proposed Rule Avoids Overcontrol Because The Proposed Rule Fails to Evaluate Alternative Cost Thresholds for Non-EGUs.

EPA claims that the Proposed Rule continues to "apply the same approach as the prior three CSAPR rulemakings for evaluating 'significant contribution' at Step 3" including "evaluat[ing] NOX reduction potential, cost, and downwind air quality improvements available at various mitigation technology breakpoints (represented by cost thresholds)" and states that this approach "was upheld by the U.S. Supreme Court in *EPA v. EME Homer City*."[39] EPA is partially correct. The approach used by EPA in its prior three CSAPR rulemakings was upheld in *EPA v. EME Homer City* (subject to the ability of petitioners to pursue any as-applied challenges based on allegations of overcontrol). But that is not what EPA did in this Proposed Rule.

EPA's approach in the Proposed Rule is crucially different from that upheld by the courts in the past, because here EPA did ***not*** evaluate "NOx reduction potential, cost, and downwind air quality improvements available at various mitigation technology breakpoints (represented by cost thresholds)" with respect to non-EGUs. Instead, as explained below, EPA selected a cost-efficiency threshold for non-EGU controls based solely on total reductions available, instead of setting a cost threshold based on the controls strictly necessary to achieve attainment at downwind linked receptors. Accordingly, the control level selected for non-EGUs is wholly inconsistent with EPA's prior approach, has no basis in prior precedent, and fails to demonstrate that EPA is avoiding overcontrol, particularly since EPA failed to model whether a lower cost threshold for non-EGUs sources may also have achieved attainment at downwind receptors.

In the *EME Homer* CSAPR litigation, the Supreme Court approved an approach of modeling the reductions associated with several different cost thresholds of potential controls, and setting the cost threshold (and thus controls) at the lowest level needed to achieve attainment in downwind receptors.[40] But here, EPA set a cost threshold for non-EGUs based on the maximum

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[38] Note that the stringency of controls is conceptually distinct from the amount of emissions reductions. If a given level of control on whatever industry most contributes to a downwind linked nonattainment or maintenance receptor is insufficient to fulfil a state's Good Neighbor obligation (something EPA has not demonstrated since EPA has not yet either modeled the highest industry contributors on a state by state basis, or accurately modeled the level of controls proposed in the rule), then the applicability of the controls can be extended to additional sources or industries, rather than requiring a specific industry to be more tightly controlled in an upwind state than RACT would require in the downwind state.

[39] Proposed Rule at 20,055.

[40] *EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489, 500 (2014) ("Under the Transport Rule, EPA employed a 'two-step approach' to determine when upwind States 'contribute[d] significantly to nonattainment,' and therefore in 'amounts' that had to be eliminated. At step one, called the 'screening' analysis, the Agency excluded as de minimis

amount of emission reductions potentially achievable (rather than based on the amount needed to resolve downwind receptors), and only modeled controls at that cost threshold ($7,500) without ANY modeling to see if incrementally lower cost thresholds could also achieve attainment at downwind receptors.[41]

Notably, EPA's use of cost thresholds in the Proposed Rule was radically different for EGUs and non-EGUs. The Proposed Rule's support documents do consider several incremental cost thresholds for EGUs in creating modeling scenarios, ranging from $1,600 to $11, 000. But for non-EGU's, EPA instead:

1. aggregated all proposed industries together, instead of setting industry specific cost thresholds like EPA did for EGUs;
2. selected only a single control scenario for consideration (i.e. all controls up to $7,500/ton) rather than the many control levels modeled for EGUs; and
3. rather than varying the level of controls required to reduce emissions from a set list of significant facilities (like the rule does for EGUs), for non-EGUs, the only modeling variations run by EPA were changing which units a preordained level of controls would be applied to.

As explained in the Policy Analysis TSD, only the following scenarios were modeled for their effect on ppb ozone concentrations at downwind receptors:[42]

- Engineering Analysis Base
- EGU only $1,600 cost threshold (SCR Optimize + Generation Shifting)
- EGU only $1,600 cost threshold (SCR Optimize + SOA CC + Generation Shifting)
- EGU only $1,800 cost threshold (SCR Optimize + SNCR Optimize + Generation Shifting)

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any upwind State that contributed less than one percent of the three NAAQS to any downwind State 'receptor,' a location at which EPA measures air quality. . . The remaining States were subjected to a second inquiry, which EPA called the 'control' analysis. At this stage, the Agency sought to generate a cost-effective allocation of emission reductions among those upwind States 'screened in' at step one. The control analysis proceeded this way. EPA first calculated, for each upwind State, the quantity of emissions the State could eliminate at each of several cost thresholds. . . . The Agency then repeated that analysis at ascending cost thresholds. Armed with this information, EPA conducted complex modeling to establish the combined effect the upwind reductions projected at each cost threshold would have on air quality in downwind States. The Agency then identified 'significant cost threshold[s],' 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.' For example, reductions of NOX sufficient to resolve or significantly curb downwind air quality problems could be achieved, EPA determined, at a cost threshold of $500 per ton (applied uniformly to all regulated upwind States).") (internal citations omitted).

[41] Proposed Rule at 20083; see also Non-EGU Screening Assessment at 4.

[42] See Policy Analysis TSD at 55-57, Tables C-12, C-13, and C-14.

- EGU only $1,800 cost threshold (SCR Optimize + SOA CC + SNCR Optimize + Generation Shifting)
- EGU only $11,000 cost threshold (SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting)
- EGU $11,000 cost threshold plus non-EGU Tier 1 at $7,500 cost threshold (SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting + non-EGU Tier 1)
- EGU $11,000 cost threshold plus non-EGU Tiers 1&2 at $7,500 cost threshold (SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting + non-EGU Tier 1 + Tier 2)

Accordingly, as noted above, although different cost thresholds were evaluated for EGUs, *EPA never modeled the effect of different cost thresholds for non-EGUs*. Likewise, the "less stringent" and "more stringent" scenarios evaluated in the Regulatory Impact Analysis for non-EGUs only vary the scope of units evaluated, with the less stringent scenario subjecting fewer units to the Proposed Rule, and the more stringent scenario subjecting all Tier 1 and 2 units to the Proposed Rule regardless of their size, but all such scenarios assumed the same cost threshold for level of controls for all non-EGU regulatory scenarios.[43] Thus EPA has not demonstrated that the selected control efficiency of $7,500 per ton for non-EGUs avoids overcontrol, as compared to some lesser cost threshold (e.g. reflecting solely combustion controls like low-NOx burners and optimizations, without post combustion SCR retrofits), since EPA failed to model the effect of any lesser cost thresholds for non-EGUs.

This failure to model alternate cost scenarios is particularly untenable given that EPA's own cost modeling clearly showed that Tier 1 industries like Iron and Steel manufacturing had a "knee in the curve" at $1,000, and not the $7,500 threshold selected by EPA, as discussed below in the section regarding cost of controls.[44]

Because EPA failed to model the impact of control scenarios for non-EGUs associated with any lower cost threshold, the EPA has failed to demonstrate that the cost threshold chosen represents the lowest level of necessary controls that will "only limit emissions 'by just enough to permit an already-attaining State to maintain satisfactory air quality.'"[45]

[43] See Regulatory Impact Analysis at ES-7.

[44] See non-EGU Screening Analysis at 4, showing different cost-effective thresholds for Tier 1 and Tier 2 industries, but then ignoring this clear data and only evaluating the aggregate $7,500 cost threshold.

[45] *EME Homer City Generation, L.P. v. E.P.A.*, 795 F.3d 118, 137 (D.C. Cir. 2015) (quoting *EPA v. EME Homer City Generation, L.P.*, 572 U.S. at 515 n.18).

IV. EPA Fails to Demonstrate that the Proposed Limits and the Theoretical Controls They are Based on Are Technically Feasible at the Facility and Unit Specific Level.

It would be arbitrary and capricious to require something that is not possible.[46] Yet, as explained in more detail below, the Proposed Rule would impose limits on iron and steel emission units below what have ever been achieved in the industry, based on little more than speculation about feasibility of controls that have never been demonstrated in practice in the industry. And in any case, EPA must show more than bare possibility to justify the emission limits in the Proposed Rule. Congress has made the express determination that "reasonably available control technology" (RACT) is the appropriate level of control when addressing even nonattainment areas themselves.[47] And it would be arbitrary and inconsistent with the scheme of Title I and intent of Congress for sources in upwind states to be subject to limits stricter than the RACT limits applicable within nonattainment areas. In interpreting this standard, EPA has consistently found that "RACT for a particular source continues to be determined on a case-by-case basis considering the technological and economic feasibility of reducing emissions from that source."[48] In evaluating technical feasibility EPA must evaluate, on a facility and emission unit specific basis, "the source's process and operating procedures, raw materials, physical plant layout, and any other environmental impacts such as water pollution, waste disposal, and energy requirements" "the operation of and longevity of control equipment" "the space available in which to implement such changes" and "Reducing air emissions may not justify adversely affecting other resources by increasing [other types of] pollution" or "creating excessive energy demands."[49] Accordingly, EPA is correct to speak throughout the Proposed Rule about whether the controls proposed are "feasible" and "appropriate,"[50] but EPA must do more than talk about appropriateness, EPA must demonstrate that the proposed limits are both technically and economically feasible on a facility specific basis. This EPA has not done, and the Proposed Rule is unlawful without doing such analysis. And in any case, EPA has an independent "duty to examine [and justify] key assumptions as part of its affirmative 'burden of promulgating and explaining a non-arbitrary, non-capricious rule. . . .'"[51] and EPA may not "promulgate rules on the basis of inadequate data, or on data that,

[46] Notably even EPA relies on not being required to achieve the impossible. See Proposed Rule at 20062 ("implementing good neighbor obligations beyond the dates established for attainment may be justified on a proper showing of impossibility or necessity.").

[47] 42 U.S. Code § 7502; see also State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990; Supplemental, 57 Fed. Reg. 18,070, 18,073 (April 28, 1992).

[48] State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990; Supplemental, 57 Fed. Reg. 18,070, 18,073 (April 28, 1992).

[49] Id. at 18,073-74.

[50] E.g., Proposed Rule at 20,043, 20,056, 20,076, 20,080, 20,090 (discussing whether control technologies, measures and strategies, compliance flexibility, timing, and cost are "appropriate"); see also id. at 20144, 20147 (discussing whether certain limits are "feasible or appropriate").

[51] *Appalachian Power Co. v. EPA*, 328 U.S. App. D.C. 379, 135 F.3d 791, 818 (1998).

to a critical degree, is known only to the agency."[52] And thus EPA's assumptions regarding feasibility in the Proposed Rule must be adequately justified, yet, as explained in more detail in later sections herein specific to different types of U.S. Steel's operations, EPA has not done so.

V. EPA's Cost Analysis is Not Reasonable

As noted elsewhere in these comments, EPA must consider economic feasibility in setting control measures under RACT, the standard Congress has specified as applicable to NAAQS nonattainment areas.**53** EPA does have some discretion when setting cost effectiveness thresholds in rulemaking proceedings. But, "the law does require EPA to 'cogently explain why it has exercised its discretion in a given manner.'"[54] Furthermore, although EPA is entitled to make assumptions in its cost analyses, it has a "duty to examine [and justify] key assumptions as part of its affirmative 'burden of promulgating and explaining a non-arbitrary, non-capricious rule. . . .'"[55] EPA may not "promulgate rules on the basis of inadequate data, or on data that, to a critical degree, is known only to the agency."[56] EPA's approach to cost estimates and cost thresholds in the rule violate these principles and/or makes unreasonable assumptions and conclusions in a variety of ways as explained below.

A. EPA's Ignores High Variability of SCR Retrofit Costs

EPA acknowledges that its cost estimates are averages, and not reflective of individual facility retrofit costs. [57] But EPA does not address its historic acknowledgment that SCR retrofit costs are highly variable on a facility-by-facility basis making it inappropriate to apply an industry average cost threshold to all facilities in an industry outside of an emission trading program.

In prior Good Neighbor rulemakings, when commenters pointed to the high variability in cost as a critique of EPA's consideration of SCR as an available retrofit technology, EPA acknowledged high variability of SCR retrofit costs, but replied that such variability was not an issue because the emission trading scheme imposed in such prior regulatory regimes "incentivizes emission reductions at units where they are cheapest" and allowed for a choice between installing the controls, or purchasing emission credits such that reductions need not be done at facilities with high retrofit costs.[58] That rationale does not apply here. EPA expressly rejects an emission trading

[52] *Portland Cement Ass'n v. Ruckelshaus*, 158 U.S. App. D.C. 308, 486 F.2d 375, 391-93 (1973).

[53] See State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990; Supplemental, 57 Fed. Reg. 18,070, 18,073 (April 28, 1992).

[54] *Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134, 1142-43 (9th Cir. 2015) (internal citations omitted) (in regional haze context, striking down a BART determination where EPA provided no supporting rationale for why one cost level was acceptable, but another was not).

[55] *Appalachian Power Co. v. EPA*, 328 U.S. App. D.C. 379, 135 F.3d 791, 818 (1998).

[56] *Portland Cement Ass'n v. Ruckelshaus*, 158 U.S. App. D.C. 308, 486 F.2d 375, 391-93 (1973).

[57] Proposed Rule at 20,090.

[58] EPA Response to Comments to the Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS, pg. 98.

scheme for non-EGUs. Instead, under the command-and-control scheme adopted by EPA in the Proposed Rule, all impacted non-EGU emission units, particularly in the iron and steel industry subcategory, are essentially required to install SCRs regardless of the site-specific costs. EPA cannot continue to rely on an industry average cost to find SCR as categorically cost effective as EPA attempts to do in the Proposed Rule.

B. Cost Estimates Inaccurately Assume Year-Round NOx Reductions.

EPA's cost-per-ton reduction calculations are unreasonably skewed because they assume that SCR will be run all year at facilities that install it and calculates expected cost per ton on the basis of annual tons of NOx reduced, despite the fact that the NOx emission reductions being sought by EPA in the Proposed Rule are only to address ozone season emissions. For instance, EPA estimates that selection of SCR in the iron and steel industry may be associated with 948 ozone season NOx reductions, at an annual cost of $9,886,092. [59] If EPA had calculated the cost per ozone season ton of NOx reduced, this would result in an estimate of $10,428 per ton of NOx reduced[60] (notably above the cost threshold of $7,500 set by EPA). But EPA instead, without justification, lists the average cost per ton as $4,345[61], which would only be the case if the ozone season tons were extrapolated to assume continuous annual reductions.[62]

This is erroneous both legally and factually. As a legal matter, EPA only has authority to reduce ozone season emissions under the Proposed Rule and thus should limit itself to assessing the cost of ozone season reductions. Furthermore, as a factual matter, facilities will not operate SCR during the non-ozone season as EPA has acknowledged in the Proposed Rule in "quite typical" in the context of EGUs.[63] There are sound technical, economic, and environmental reasons for not operating SCR outside the ozone season, particularly due to the O&M cost associated with operation of the SCR, and in order to attempt to extend the life of the catalyst given the high cost of replacing the catalyst and how quickly the catalyst can be deactivated under the process characteristics of iron and steel furnaces such as BOFs and EAFs, as discussed above, if it were run continuously. For both independent reasons, costs estimates should instead account for the cost per ozone season ton reduced. (which is in many cases higher than the $7,500/ton screening threshold set by EPA even using EPA's own cost estimates).

C. Improper Aggregation of Industries in Setting Effective Control Cost Threshold

EPA's selection of a $7,500 cost threshold for selecting applicable controls was skewed high by grouping all Tier 1 and 2 industries together without justification. As shown in the below

[59] See Non-EGU Screening Assessment at Table 9.

[60] $9,886,092 / 948 = $10,428.

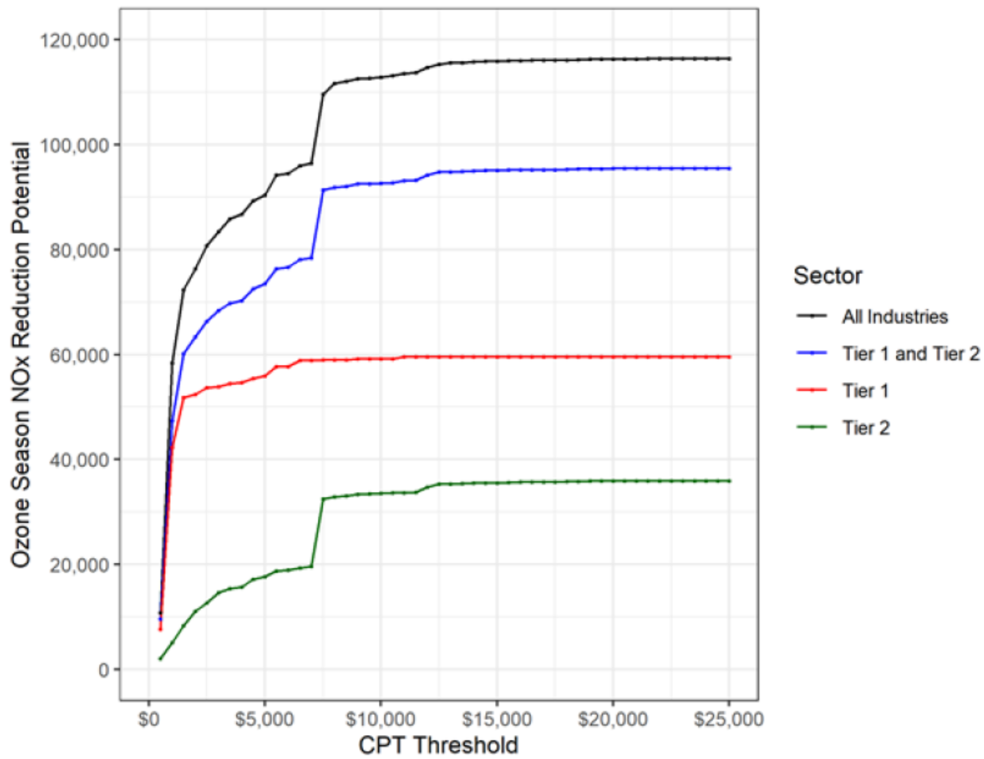
[61] See Non-EGU Screening Assessment at Table 9.

[62] $9,886,092 / (948 X (12 / 5)) = $4,345.

[63] Proposed Rule at 20,078 & n.146.

figure, EPA's cost modeling clearly showed that Tier 1 and 2 industries each had a significantly different "knee in the curve" (i.e. a significantly different cost effectiveness threshold).[64]

Figure 1. Ozone Season NOx Reductions and Costs per Ton (CPT) for Tier 1, Tier 2 Industries, and Other Industries



Based on the above chart, Tier 1 industries had a "knee in the curve" at $1,000 per ton, far lower than the cost effectiveness threshold of approximately $7,500 for Tier 2 industries. Accordingly, because this model showed that cost effectiveness could differ by industry, and because EPA conducted industry specific cost modeling for the EGU industry, EPA should have estimated industry specific cost effectiveness thresholds. But in any case, it was arbitrary for EPA to aggregate these cost curves without any explanation and thus subject all non-EGU industries to the $7,500 cost effectiveness threshold despite EPA modeling affirmatively showing that threshold was not even remotely accurate for Tier 1 industries.

VI. Modeling Problems

The modeling used in support of the Proposed Rule included many questionable and unreasonable assumptions and processes. The sections below summarize many such issues, but the attached report from Woodard and Curran includes more detailed and technical critiques of the modeling underlying the rule which EPA must consider, and which is hereby incorporated by reference.

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[64] Non-EGU Screening Assessment at Figure 1.

A. Low Precision/Accuracy:

As discussed in more detail in the attached Woodard report, EPA compared the CAMx model used by EPA to evaluate state contributions to linked receptors with actual monitoring data for each such receptor to evaluate the accuracy and precision of the CAMx model. For example, the result showed a standard deviation of 8ppb for modeling at the relevant Brazoria County, Texas receptor, [65] and only accounted for 37% of observed variation at the receptor. Although EPA claims this is on par with other CAMx models so as to not invalidate use of CAMx for the Proposed Rule, the imprecision of the CAMx modeling should be taken into account when EPA sets its levels of what contribution amount to consider to be "significant" for purposes of determining the applicability of the Proposed Rule. Given that the standard deviation for any CAMx prediction at the Brazoria receptor was up to 8pbb, it is not reasonable or rational for EPA to rely on CAMx to make finetuned distinctions between industries modeled to have impacts at 0.01ppb (the screening level selected by EPA for industry significance), since EPA's own analysis shows that the model is simply not precise enough to statistically differentiate between 0.01ppb, 0.1ppb, and 1ppb. Furthermore, EPA's communications discussed in the attached Woodard report demonstrate that EPA was aware of model "noise" due to model outputs being copied and handled over multiple operating systems and that numerical noise in model outputs could be present and could contribute to variations in modeled concentrations. If that noise was on the order of 0.01 ppb, that would be yet another reason that the modeling could not be relied on to differentiate between impacts at that level of granularity, and thus that such a level below background "noise" cannot be considered significant. Accordingly, EPA should base any determinations of modeled significance at a precision no smaller than 1pbb, so as to at least be within the same order of magnitude as the model's standard deviation.

B. False Geographic Equivalence:

EPA modeled percent reductions needed across each state as if reductions in one part of the state had the same effect as another, rather than modeling how reductions at particular sources affect the NAAQS compliance in downwind states.[66] EPA may have been able to do this under past rules which merely set statewide budgets and did not impose emission unit specific emission limits applicable on a facility level. But if EPA continues to propose facility and unit specific limits, then (as explained in Sections I, IV and XIV regarding EPA authority to issue emission unit limits applicable at a facility level) EPA must model whether such facility has an impact sufficient to justify regulating them under the Good Neighbor clause, rather than the individual limits applicable here. This is particularly true given the fact that CAMx can be used to predict facility level impacts, and EPA simply chose to run the model without that available parameter.

[65] See excel chart labeled "CAMx 2016v2 MDA8 O3 Model Performance Stats by Site".

[66] Policy Analysis at 33 n. 41.

C. Disregard of Emission Increases:

As described in the section herein concerning feasibility of SCR installation, the temperature operating range of an SCR does not match the temperature range needed for the safe and effective operation of a baghouse, such that even if it were technically feasible to install, it would likely require increasing the source's NOx, VOC, PM, SO2, CO, ammonia and greenhouse gases and other pollutants due to the need for additional natural gas and electricity needed to heat, cool, or clean up the flue gas to make it amenable to operable SCR temperature ranges and tolerances. EPA appears not to have accounted for this emission increase (or at least offset against any expected reductions). This in turn will also require analysis of whether increased VOC, PM, NOx, CO, ammonia, etc. emissions as a result of installing SCR would have an adverse effect on compliance with other NAAQS.

D. Ignoring Emission Reductions in Favor of Overcontrol:

As noted above, the model appears to significantly underpredict emission reductions associated with the Proposed Rule, by not even attempting to include all facilities subject to the Proposed Rule or attempting to quantify the actual reductions resulting from the emission limits in the Proposed Rule. This is important to correct before issuing a final rule because ignoring emission reductions resulting from the Proposed Rule would lead to impermissible overcontrol by setting limits that reduce emissions by far more than EPA has modeled are necessary to result in attainment (especially with respect to the Brazoria County, Texas receptor). Accordingly, if EPA intends to proceed with implementing unit specific control emission limitations, EPA must either redo the overcontrol analysis using estimated reduction estimates based on the emission limits proposed in the Proposed Rule, and/or EPA must make the limits less stringent so as to match the statewide emission reductions modeled to not result in downwind attainment without overcontrol.

E. Erroneously Assuming Linear Impacts:

EPA assumed impacts were linear between emission reductions and ppb reductions at receptors, even though EPA acknowledged they are not in fact linear.[67] Although EPA attempted to account for the nonlinear relationship by applying an adjustment factor that is specific to the state and receptor, such adjustment factors do not account for different locations of emission sources within a given state and thus do not adequately correct the erroneous assumption of linear reductions. This is particularly problematic with respect to the U. S. Steel's Arkansas facility, since it is on the far opposite side of the state from the Brazoria County, Texas receptor, yet EPA's adjustment factors treat any reduction at U. S. Steel's Arkansas facility the same as NOx sources in places like Texarkana and El Dorado which are hundreds of miles closer to the Brazoria receptor. Moreover, EPA fails to provide any rationale for why it is accurate or reasonable to apply the same adjustment factor for these geographically remote locations to correct EPA's admittedly erroneous assumption regarding linearity of impacts in relation to emission reductions. Finally, the HYSPLIT modeling conducted by Woodard & Curran and discussed below in Section

[67] Policy Analysis at 33 n. 42.

XIV. of these comments shows that it is important to differentiate between effect of impacts in different portions of the state, because EPA's assumptions of linearity regardless of location in the state is contradicted by the back-trajectories modeled by HYSPLIT, demonstrating that the U. S. Steel's Arkansas facility is not linked to ozone high days at the Brazoria receptor.

F. Mismatch Between Modeled Reduction and Proposed Controls:

EPA's modeling does not accurately reflect the control efficiencies EPA assumes (and requires) in the Proposed Rule. For instance, it appears that EPA performed a modeling run where EPA assumed emission reduction of 30% across all covered sources to demonstrate attainment status at nonattainment and maintenance receptors, and a model run based on the statewide emission reductions EPA expected based on the non-EGU screening assessment. But neither of these modeling runs reflect the emission standards that EPA actually proposes. As previously noted, the modeling run based on the non-EGU screening assessment significantly undercounted emission reductions associated with the Proposed Rule limits. And the modeling run assuming across the board reductions of 30% likewise does not match the limits in the Proposed Rule, which assume unit specific limits far more stringent than 30% in many cases. For EAFs, for instance, "EPA based the emission limit of 0.15 lb/ton of steel on projected reduction efficiency of 40-50% as compared to existing permit limits for EAFs".[68] EPA cannot haphazardly model one set of assumptions and then propose something totally different. EPA should conduct modeling that actually reflects the rule being proposed.

G. Improper Significance Screening Threshold

It is unreasonable for EPA to depart from its August 2018 memorandum regarding determinations of state significant contribution thresholds by now requiring evaluation in light of a 0.7 ppb significance threshold rather than the 1 ppb significance threshold approved in the August 2018 memo.

In the first place, EPA's August 2018 memo provided modeling to support the conclusion that a 1 ppb threshold is generally comparable to a 1% threshold for the 2015 ozone NAAQS in terms of the contributions it would cover, and it is arbitrary for EPA to abandon that conclusion without performing any technical analysis to suggest that EPA's prior conclusion is flawed, or even retracting the August 2018 memo.

Second, 1 ppb is the significant digit for reporting ozone monitoring data under the NAAQS.

Third, the imprecision of EPA's modeling (as discussed above) demonstrates that a significance threshold below 1 ppb simply cannot be justified since the model lacks the capability to distinguish impacts below that level.

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[68] Non-EGU Sectors TSD at 43.

Finally, EPA has already determined that 1ppb represents the level at which a single facility presents a significant impact under the 8 hr Ozone NAAQS in the context of PSD permitting.[69] In making the determination that 1ppb represents the significant impact level (SIL) for evaluating whether a given source may contribute significantly to any attainment issues with the 8 hr Ozone NAAQS, EPA engaged in actual statistical analysis to find what "degree of change in concentration is, thus, indistinguishable from the inherent variability in the measured atmosphere and may be observed even in the absence of the increased emissions from a new or modified source" and determined that "changes in air quality within this range [i.e., the relevant SIL] are not meaningful, and, thus, do not contribute to a violation of the NAAQS."[70] By contrast, EPA provides no analysis for why the various proposed significance screening levels in the Proposed Rule (0.7ppb for an entire state, and 0.01 for an entire industrial sector) represent a significant contribution with respect to air quality at downwind receptors.[71]

EPA bases its significance level for statewide emissions on consistency with past CSAPR rulemakings.[72] To be sure, such prior rulemakings also used 1% of the relevant NAAQS as a screening threshold for screening out states without any significant contribution, and that threshold was upheld in 2014 by the Supreme Court in *EME Homer*. But crucially, the past rulemakings EPA points to and the Supreme Court's decision in *EME Homer* all pre-date EPA's 2018 publication of the Ozone SIL and associated modeling and express finding that any contribution under 1ppb is indistinguishable from background variability and thus cannot be characterized as a significant contribution. EPA cannot simply ignore its own more recent modeling and determinations with respect to the 8hr Ozone NAAQS simply by saying it wishes to be consistent with assumptions made before the SIL analysis and determinations were made by EPA. EPA must at minimum explain why it is concluding that a level may constitute a significant contribution that EPA has previously determined by statistical analysis to *not* be significant.

EPA bases its significant contribution threshold for all non-EGU industries on an eyeballed review of a figure comparing relative impacts of different industries, and EPA concludes based on subjective review that "perhaps 0.05 ppb or 0.01 ppb could serve as breakpoints in the data" but ultimately selects 0.01 ppb as "a meaningful conservative breakpoint for screening out non-impactful industries."[73] This analysis is flawed for multiple reasons. First, in selecting 0.01 pbb, EPA asked the wrong question, namely, "what are we confident is so de-minimis as to be

[69] EPA, Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program (April 17, 2018). https://www.epa.gov/sites/default/files/2018-04/documents/sils_policy_guidance_document_final_signed_4-17-18.pdf.

[70] EPA, Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program (April 17, 2018). https://www.epa.gov/sites/default/files/2018-04/documents/sils_policy_guidance_document_final_signed_4-17-18.pdf.

[71] Compare, 42 U.S. Code § 7410(a)(2)(D)(i)(I), limiting application of the Good Neighbor provision to "amounts which will . . . contribute significantly to nonattainment".

[72] Proposed Rule at 20,074.

[73] Non-EGU Screening Assessment at 22-23.

justifiably screened out" rather than the question posed by the statute, i.e., "what is significant enough to constitute a significant contribution." Although it is justifiable to screen out any industry with impacts below 0.05 or 0.01 pbb impacts to downwind nonattainment and maintenance receptors, that does not mean that it is reasonable to automatically assume that anything above that level is a significant impact. Even more importantly, EPA's subjective comparison of industries to each other can at most only answer the question "what industries are more significant than other industries" and not the statutory question of what "amount" of emissions constitutes a "significant contribution" to downwind receptors. Actually, demonstrating what impact constitutes a significant contribution instead requires statistical analysis evaluating the variation in the Ozone 8-hour design value at each monitoring site, to prove that 0.01 ppb is indeed a threshold above which out of state NOx emissions could significantly impact Ozone attainment, something EPA has not attempted here. In any case, it is arbitrary for EPA to conclude 0.01 ppb from an entire industry can constitute a significant contribution to downwind receptors without even addressing EPA's prior statistical analysis concluding that any amount below 1ppb from even an individual facility is "not meaningful" and so insignificant as to be "indistinguishable from the inherent variability" at downwind receptors and "not contribute to a violation of the NAAQS."

H. Failure to do Any Backtrajectory Modeling or Otherwise Evaluate Consistency and Persistence of Impacts Predicted in CAMx

The model used by EPA (CAMx) only looks at five to ten elevated ozone days in forming its conclusions regarding state contributions to linked predicted nonattainment and maintenance receptors. Due to the complexity of the subject matter, it is questionable whether this small sample size reasonably reflects consistency of predicted contributions. In any case, because EPA does not evaluate consistency and persistence of the impacts found, EPA should have performed some other backtrajectory modeling, such as HYSPLIT, to confirm what geographic regions were contributing to days predicted to be over the NAAQS. At a minimum this should have been performed for Arkansas and Mississippi which were linked to only a single downwind maintenance receptor, to evaluate what sources and geographic areas could be contributing to these predicted high-ozone days, and whether any impact on the maintenance receptor is truly consistent and persistent enough to be classified as a significant contribution. After all, it would not be reasonable to consider an inconsistent or transient effect a "significant contribution." Notably, EPA itself used HYSPLIT in this rulemaking to evaluate environmental justice impacts on a facility specific level for EGUs[74] (though EPA did not use it to evaluate EPA's authority to regulate individual facilities under the Proposed Rule in the first place). EPA has also previously approved the use of HYSPLIT to screen out areas in the similar context of regional haze.[75]

Because EPA failed to perform the modeling needed to assess the significance of state and facility contributions to downwind receptors in the first instance, and because it bears directly on EPA's authority to regulate facilities and states at all under the Good Neighbor provision, EPA

[74] Policy Analysis TSD at 67.

[75] 87 Fed. Reg 7734 (Feb 10, 2022).

must consider any such CAMx or HYSPLIT modeling whenever it is completed in determining applicability of any final rule.

I. Elimination of "Well Controlled Sources"

EPA makes the cryptic observation that it "well-controlled sources that still emit > 100 tpy are excluded from consideration" as part of the modeling related to the non-EGU Screening Assessment, including compliance costs and the emission reductions required in order to meet Good Neighbor obligations.[76] EPA does not explain how a source was determined to be "well controlled" enough to be excluded, and in any case, because EPA expressly set the emission limits in the Proposed Rule below anything EPA found that any emission unit in the iron and steel industry currently achieved. Notwithstanding, any so-called "well controlled" source EPA eliminated from analysis must still have been above the Proposed Rule limits. Accordingly, EPA must explain why sources were excluded from analysis as "well controlled" despite presumably not being well controlled enough to meet the limits EPA now proposes. Although EPA enjoys flexibility in how to perform modeling, it has a "duty to examine [and justify] key assumptions as part of its affirmative 'burden of promulgating and explaining a non-arbitrary, non-capricious rule. . . .'"[77] and EPA may not "promulgate rules on the basis of inadequate data, or on data that, to a critical degree, is known only to the agency."[78]

J. Internal Inconsistency Regarding Anticipated Reductions

The Proposed Rule contains many internal inconsistencies regarding the extent of reductions assumed by EPA in performing modeling and setting proposed emission limits. For example, just with respect to EAFs, the rule Proposed Rule states that it "[a]ssumes 25% reduction by SCR," whereas the Non-EGU Sectors TSD states that it projects "efficiency of 40-50% as compared to existing permit limits for EAFs" and "minimally 40% NOx reduction efficiency is achievable by use of low-NOx technology, including potential use of low-NOx burners and selective catalytic reduction."[79] And the Non-EGU Screening Assessment estimated no reductions from EAFs.[80] In order to draft a non-arbitrary rule, EPA must make a consistent assumption about the emission reductions associated with the Proposed Rule, and actually use that same assumption when modeling costs, feasibility, and air quality impacts at downwind receptors.

K. Use of AEO Rather Than Current Emission Inventories

When describing the non-EGU emission inventory development used in the air quality modeling to identify nonattainment and maintenance areas and the significance of state contributions thereto, the Proposed Rule states that EPA started from the 2016v2 platform, then

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[76] Proposed Rule at 20,083.

[77] *Appalachian Power Co. v. EPA*, 328 U.S. App. D.C. 379, 135 F.3d 791, 818 (1998).

[78] *Portland Cement Ass'n v. Ruckelshaus*, 158 U.S. App. D.C. 308, 486 F.2d 375, 391-93 (1973).

[79] Non-EGU Sectors TSD at 43.

[80] Non-EGU Screening Assessment at Table 6.

"The future year non-EGU point inventories were grown from 2016 to the future years using factors based on the AEO 2021 . . ." [81] But AEO 2021 does not appear to be an industry emissions inventory, but instead only appears to track energy consumption in various industries.[82] It is not reasonable to use this approach when EPA had actual emission inventories (such as the 2019 NEI) available, particularly for EAFs. Unlike EGUs, whose emissions might be expected to strongly correlate to energy consumption at the plant, EAFs NOx emissions are not primarily driven by by the combustion of fossil fuels. Thus, EPA should compare actual updated emission inventories with the AEO to demonstrate its accuracy and appropriateness as a basis for developing emission inventories.

VII. The Proposed Rule Runs Afoul of Many Legal Doctrines:

A. Major Questions Doctrine:

Multiple aspects of the Proposed Rule implicate the major questions doctrine which provides that agencies cannot unilaterally resolve questions of "vast economic or political significance" unless Congress has unambiguously authorized it to do so.[83]

1. The Proposed Rule would mandate generation shifting in the EGU sector in many ways, first, EPA sets emission budgets for EGUs based on assuming that generation shifting will occur, [84] which is a form of expressly requiring generation shifting, by setting limits too low to achieve in the absence of generation shifting. Second, EPA further forces generation shifting through the creation of the "backstop daily rate for large coal EGUs"; which would only apply to coal fired plants, and not natural gas plants,[85] and are expressly designed to make coal fired EGUs, but not natural gas fired EGUs, either "retrofit [with SCR] or retire."[86] This solely targets coal in order to reshape the energy sector to EPA's preferences, in a similar manner to that at issue in the challenges to the Affordable Clean Energy and Clean Power Plan rules. The Supreme Court has accepted review of a set of cases challenging those rules, arguing that the major questions doctrine prohibits EPA from forcing generation shifting or otherwise restructuring the nation's energy system.[87] A decision is expected by June 2022, and any final rule must account for and comply with any interpretation of the major questions doctrine in that case.
2. The Proposed Rule's historically unprecedented use of the Good Neighbor provision to impose emissions limits on a unit specific basis for entire industries, without any

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[81] Proposed Rule at 20,064.

[82] See AEO 2021, narrative available at https://www.eia.gov/outlooks/aeo/pdf/AEO_Narrative_2021.pdf

[83] Util. Air Regul. Grp. v. EPA, 573 U.S. 302, 324 (2014).

[84] Proposed Rule at 20,081.

[85] Proposed Rule at 20,110-11.

[86] Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard, at ES-7.

[87] See West Virginia v. Environmental Protection Agency, No. 20-1530, and linked cases.

consideration of unit specific feasibility or demonstration that the source itself is contributing to any nonattainment or maintenance site also runs afoul of the major questions doctrine. The text of the Good Neighbor provision, which focuses only on limiting amounts of emissions significantly contributing to actual nonattainment of maintenance issues in downwind states does not clearly authorize the vast industry shaping and reorganizing that EPA attempts to issue in the Proposed Rule.

B. Chevron Doctrine

Multiple aspects of the Proposed Rule exceed the discretion granted to EPA under the statutory text, and thus will not be protected by *Chevron* deference,[88] and may serve as a basis for challenges to *Chevron* itself, or at least to further limits on EPA's deference under *Chevron*.

1. The Proposed Rule only applies by virtue of EPA's disapproval of various SIP plans. In disapproving those state plans (which is a statutory prerequisite for EPA authority to issue the Proposed Rule) EPA effectively asserted that it would prefer to institute a FIP as opposed to individual SIP demonstrations due to a wish to address ozone transport in a "nationally uniform approach" with "nationwide scope and effect" based on a "common core of nationwide policy judgements."[89] But EPA lacks discretion to decide that regional ozone transport is a national problem that requires national uniformity (e.g. by setting industry wide emission limits based on a "common core of nationwide policy judgements" without regard to state specific contribution considerations). Congress already unambiguously made a contrary decision by making EPA's discretion to implement a FIP subject to SIP submissions that EPA "shall" approve if the statutory elements are met. *See* 42 U.S.C. § 7410(k)(3); CAA Sec. 107(a) ("Each State shall have the primary responsibility for assuring air quality within the entire geographic area comprising such State by submitting an implementation plan for such State which will specify the manner in which national primary and secondary ambient air quality standards will be achieved and maintained within each air quality control region in such State." Simply put, EPA lacks discretion to decide that it would prefer a uniform national approach for Good Neighbor provisions. *Train v. Natural Resources Def. Council*, 421 U.S. 60, 79 (1975) ("The Act gives the Agency no authority to question the wisdom of a State's choices of emission limitations if they are part of a plan which satisfies the standards of § 110(a)(2), and the Agency may devise and promulgate a specific plan of its own only if a State fails to submit an implementation plan which satisfies those standards."); *Concerned Citizens of Bridesburg v. U.S. E.P.A*, 836 F.2d 777, 780–81 (3rd Cir. 1987) (holding the Clean Air Act "left the mechanics of achieving NAAQS to the states. Section 7410(a) requires each state to formulate and submit to the EPA a SIP detailing regulations and source-by-source emissions limitations that will conform the air quality within its boundaries to the NAAQS. The SIP basically embodies *a set of choices regarding such matters as transportation,*

[88] *See Chevron U.S.A., Inc. v. Natural Resources Defense Council, Inc*., 467 U.S. 837 (U.S. 1984).

[89] 87 Fed. Reg. 9798, 9801, 9835 (Feb. 22,2022).

zoning and industrial development that the state makes for itself in attempting to reach the NAAQS with minimum dislocation. Because the states have primary responsibility for achieving air quality standards, the EPA has limited authority to reject a SIP."); *Commonwealth v. Environmental Protection Agency*, 108 F.3d 1397, 1410 (D.C. Cir. 1997) ("section 110 does not enable EPA to force particular control measures on the states"). Accordingly, EPA deserves no deference in any decision to prefer a nationwide FIP based on a "common core of nationwide policy judgements" over a SIP based on "a set of choices regarding such matters as transportation, zoning and industrial development that the state makes for itself."

2. EPA's decision to subject sources in upwind states to control limits stricter than the RACT level of control Congress has set for NAAQS compliance in even nonattainment areas is outside the discretion of EPA, and clearly conflicts with the structure of Title I of the Clean Air Act, the Good Neighbor provision, and the intent of Congress, and does not merit *Chevron* deference.

3. As discussed in detail throughout these comments, the many ways in which EPA analyzes and proposes to regulate non-EGUs in ways different than what has been upheld for EGUs in prior Good Neighbor rulemakings, and the various other unreasonable or arbitrary positions identified throughout these comments are not reasonable interpretations of the statute, and do not merit *Chevron* deference.

C. EPA's Consideration of Co-Benefits to Calculate Benefits of the Rule is Not Reasonable and is Arbitrary in Light of Other EPA Rulemakings

EPA justifies the costs of the Proposed Rule by accounting for not only the costs associated with ozone formation based on NOx reductions, but also based on climate impacts expected from expected co-reductions of CO2, and PM2.5 reductions based on expected co-reductions of PM2.5 and SO2.[90]

This is not reasonable or appropriate, because the statutory basis for such limits is grounded in assessing just the pollutants involved in the specific NAAQS at issue. For each NAAQS, the Good Neighbor provision provides that implementing plans may limit "any air pollutant" that contributes significantly to compliance issues with "*such national primary or secondary ambient air quality standard.*"[91] Accordingly, e.g., for the specific ozone NAAQS, the Good Neighbor

[90] E.g., Proposed Rule at 20,155; 20167; see also Regulatory Impact Analysis at 5-4 through 5-26 (incorporating PM2.5 reduction estimates when calculating health and economic benefits of the rule) & Table ES-7 through ES 10 (footnote to each admit that the "ozone benefits" in the tables actually aggregate benefits from reductions of ozone AND PM2.5) & 5-26 through 5-31 (assessing climate impacts of the rule based on CO2 co-reductions, and stating that although the EPA did not quantify benefits from CO2 reductions, EPA nevertheless took them into account as "unquantified benefits of this proposal" when evaluating the benefits of the rule; see also Data and Results for the Monetized Health Benefits Analysis as part of the Regulatory Impact Analysis.

[91] 42 U.S. Code § 7410(a)(2)(D)(i)(I).

provision allows regulation of any pollutant that contributes to compliance issues with the Ozone NAAQS (e.g. NOx), but not pollutants unrelated to Ozone compliance (CO2, PM2.5, SO2, etc.).

Moreover, EPA's approach to "baking-in" co-benefit considerations is arbitrary because it is incompatible with EPA's current promulgated final rule assessing the appropriateness of accounting for co-reductions of pollutants other than the pollutant subject to a particular regulation.[92] When assessing the appropriateness of taking into account benefits of non-HAP reductions in the context of the Clean Air Act's HAP regulations under section 112 of the Clean Air Act, EPA found that "the EPA's equal reliance on the particulate matter (PM) air quality co-benefits projected to occur as a result of the reductions in HAP was flawed as the focus of CAA section 112(n)(1)(A) is HAP emissions reductions."[93] More specifically, "Indeed, it would be highly illogical for the Agency to make a determination that regulation under CAA section 112, which is expressly designed to deal with HAP, is justified principally on the basis of the criteria pollutant impacts of these regulations. That is, if the HAP related benefits are not at least moderately commensurate with the cost of HAP controls, then no amount of co-benefits can offset this imbalance for purposes of a determination that it is appropriate to regulate under CAA section 112(n)(1)(A)."

Although CAA Sections 112(n)(1)(A) and 110(a)(2) are separate statutory schemes, the cost/benefit analysis must be treated consistently because both treatment of cost under each provision is based on the same question: whether a given regulation is "appropriate" and "necessary." [94] Accordingly, because the Ozone NAAQS is focused on ozone reductions, any Good Neighbor implementation plan under the Ozone NAAQS should also only be considered "appropriate" if the ozone benefits are commensurate to the costs, without relying on co-benefits from PM2.5 reductions and climate considerations, since both are outside the scope of the Ozone NAAQS.

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[92] See "Proposed Rule: National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review," 84 Fed. Reg. 2670; see also "Final Rule: National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review," 85 Fed. Reg. 31,286, 31,299 (May 22, 2020) ("finalizing the determination outlined in the 2019 Proposal").

[93] 84 Fed. Reg. at 2676.

[94] *Compare* U.S. Code § 7412(n)(1)(A) ("The Administrator shall regulate electric utility steam generating units under this section, if the Administrator finds such regulation is *appropriate and necessary*"), *with* 42 U.S. Code § 7410(a)(2)(A) (providing that implementation plans for each individual criteria pollutant under Section 110 "shall" "include enforceable emission limitations and other control measures, means, or techniques (including economic incentives such as fees, marketable permits, and auctions of emissions rights), as well as schedules and timetables for compliance, as may be *necessary or appropriate* to meet the applicable requirements of this chapter").

D. EPA's Disregard for Demonstrations of Infeasibility Miscomprehends the Precedent EPA Relies On.

EPA makes the assertion that it is authorized to ignore "claims about infeasibility of controls" raised by any facility, citing solely to the D.C. Circuit's opinion in *Wisconsin v. EPA*.[95] But EPA mischaracterizes the D.C. Circuit decision. In *Wisconsin*, the court simply required that the deadline for upwind state compliance with Good Neighbor provision align with downwind states deadlines for compliance with a given NAAQS. In doing so, it is true that the court rejected an EPA argument that it was infeasible to require compliance with the Good Neighbor provision in a timely manner, but the discussion of "feasibility" was not about technical feasibility of whether controls would be capable of being retrofitted and or concerning whether controls could actually feasibly reduce the emissions to the extent needed. Rather, the "feasibility" issues the court and EPA discussed in that context instead concerned whether EPA had enough time and information to draft and implement required reductions in a timely manner.[96]

It is also readily apparent that the technical feasibility questions raised by the Proposed Rule's unit level emission limits are categorically different than the "feasibility" concerns discussed in *Wisconsin*, because the rule at issue in *Wisconsin* involved only statewide emission budgets and did not involve any command-and-control limits like those now proposed. Furthermore, it would be one thing if EPA simply had a statewide emission cap requiring absolute reductions in NOx, because then a facility could meet the limit by operating less if it is absolutely necessary for emissions to decrease in order to meet downwind attainment, but EPA's proposal goes beyond that, with the efficiency based lb/mmBtu limits that may make it literally impossible to comply if the proposed controls cannot feasibly reduce emissions to the extent EPA assumes due to the differences in the steelmaking process than coal fired powerplants, whereas overall emission budget reductions would still accomplish any mandate faced by EPA due to *Wisconsin* while giving facilities the flexibility to meet them in the most efficient and technically feasible manner, or in the worst case to operate less.

VIII. EPA's Decision to Deny Non-EGUs Compliance Flexibility is Arbitrary and Capricious

A. It is Arbitrary to Deny Non-EGUs Compliance Flexibility Granted to EGUs

A key component of the currently established CSAPR rule is that it provides for trading of NOx emission credits. The Proposed Rule itself recognizes that "the current CSAPR trading program structure . . . has important positive attributes, particularly with respect to the exceptional degree of compliance flexibility it can provide. . . .".[97] As described in the Proposed Rule, "[t]he trading program's option to buy additional allowances provides flexibility in the program for

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[95] Proposed Rule at 20,104 & n.242 (citing Wisconsin v. Envtl. Prot. Agency, 938 F.3d 303 (D.C. Cir. 2019)).

[96] See 81 Fed. Reg 74,504, 74,552 (Oct. 26, 2016) ("a remedy simply is not feasible *in the existing timeframe*. . . . the agency does not have sufficient information at this time to promulgate such a rule.").

[97] 87 Fed. Reg. at 20,107.

outlier sources that may need more time than what is representative of the fleet average to implement these mitigation strategies while providing an economic incentive to outperform rate and timing assumptions for those sources that can do so. In effect, this trading program implementation operationalizes the mitigation measures as state-wide assumptions for the EGU fleet rather than unit-specific assumptions." [98]

For non-EGUs, the Proposed Rule arbitrarily includes no similar flexibility. The Proposed Rule in fact includes no flexibility at all. There is no allowance for variances from EPA's "command-and-control" emission limits for facilities that cannot retrofit EPA's required pollution control equipment or achieve the extreme reductions the Proposed Rule prescribes even after installing EPA's selected technology. There is no process for submitting an alternative control strategy to EPA or for non-EGUs or the states in which they are located, to offset the emission reductions mandated by the Proposed Rule with other, more cost-effective emission reductions. There is not even an opportunity to extend deadlines if it is found that the required pollution control and monitoring equipment required by the Proposed Rule cannot be purchased and installed on the schedule mandated by EPA.

While the Proposed Rule should not be finalized in any form, if EPA does proceed with finalizing a FIP for interstate transport of ozone, it must afford compliance flexibility for all subject sources, not just EGUs. EPA should consider extending emission trading to non-EGUs so that a disproportionate burden is not placed on non-EGUs to achieve emission reductions not required of other sources. EPA should also include a process for regulated sources or affected states to petition for variances from the required emission limits and compliance schedules upon a demonstration of infeasibility or impracticality.

B. EPA's Decision to Exclude All Non-EGUs from the Emissions Trading System Arbitrarily Reverses Prior Agency Determinations Without Justification.

EPA's decision to exclude all non-EGU's from the emissions trading program is a major regulatory about-face by the agency which it neither recognizes nor confronts, impermissibly attempting to "depart from a prior policy *sub silentio*." *See FCC v. Fox TV Stations, Inc.*, 556 U.S. 502, 515 (2009). EPA has consistently endorsed an emissions trading program over unit-specific limitations, and the Proposal fails to adequately justify the decision to categorically exclude non-EGUs from the trading program.

In April 2021, EPA explained that the trading program "not only encourages units to achieve the rates assumed in the budget-setting process, but to perform at even better rates where better performance can be achieved at a cost lower than the allowance price. By contrast, an implementation mechanism that provides a unit-specific emission rate would not incentivize the unit to perform better than its rate requirement."[99] EPA further stated that "unit-specific short-term emission rates pose significant implementation and rulemaking challenges," and if EPA were "to

[98] *Id.* at 20,100.

[99] EPA Final Rule – Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS, pg. 65 (published April 30, 2021).

choose to implement a unit-specific emissions rate regime for implementation, the compliance flexibility afforded by emissions trading would not be available and it would not be possible to rely on fleet average information to the same extent . . . ."[100]

Nevertheless, EPA now proposes to exclude non-EGUs from the trading program. In a mere two paragraphs, EPA seeks to justify this exclusion by asserting that if it "were to include non-EGUs in the trading program, [it] would require monitoring and reporting of hourly mass emissions . . . as [it has] for all trading programs." The Proposal therefore concludes that "applying unit-level emissions limitations . . . rather than constructing an emissions trading regime is more administratively feasible and more easily implementable at the source level . . . ." This proposed exclusion is arbitrary and capricious for a number of reasons.

First, the Proposed Rule already requires the installation of monitoring equipment for non-EGUs. The Proposal explicitly states:

> "The EPA is proposing to require each owner or operator of an affected facility that is subject to the NOx emissions limit for Iron and Steel Mills and Ferroalloy Manufacturing emissions units contained in this section to install, calibrate, maintain, and operate a CEMS for the measurement of NOx emissions discharged into the atmosphere from the affected facility. The EPA is proposing that each emissions unit will be required to conduct an initial performance test and to operate CEMS to assure compliance."[101]

Thus, EPA's rationale for excluding non-EGUs from the trading program—that including them "would require monitoring and reporting," including "CEMS (or an approved alternative method)"[102]—is internally inconsistent, arbitrary, and capricious. EPA is proposing to require iron and steel industry units subject to the Proposed Rule to install CEMS or monitoring equipment anyway.

Moreover, when EPA initiated the trading program, it provided EGUs with no less than two-and-a-half years to install monitoring equipment.[103] But EPA now appears to believe that three-and-a-half years (until the compliance deadline of 2026) is an inadequate amount of time, warranting the exclusion of non-EGUs from the trading program. EPA does not provide any reason for this shift other than to note general uncertainty as to how long it may take non-EGUs to install monitoring equipment. But "where an agency is uncertain about the effects of agency action, it may not rely on 'substantial uncertainty' as a justification for its actions."[104] "Instead, EPA must

[100] *Id.*

[101] Proposed Rule, pg. 20,146 (emphasis added).

[102] *Id.* At 20,141.

[103] Clean Air Interstate Rule, 70 Fed. Reg. 25,161 (May 12, 2005).

[104] *Scholl v. Mnuchin*, 489 F. Supp. 3d 1008, 1036 (N.D. Cal. 2020), quoting *Greater Yellowstone Coal., Inc. v. Servheen*, 665 F.3d 1015, 1028 (9th Cir. 2011).

'rationally explain why the uncertainty' supports the chosen approach."[105] EPA's failure to justify its "depart[ure] from a prior policy" renders the decision to exclude non-EGUs from the trading program "arbitrary and capricious."[106]

Additionally, EPA's assertion that it has "require[d] monitoring . . . for all trading programs," lacks one crucial clarification. When EPA initiated the trading program, the provision requiring use of CEMS still provided a process for a "unit that does not meet the applicable compliance date" for installing monitoring equipment to "determine, record, and report substitute data"[107] in lieu of CEMS data. If EPA determines that CEMS are both necessary and appropriate (including but not limited to cost justified), EPA should likewise provide a process for providing "substitute data" in the hypothetical event that certain units are unable to install monitoring equipment by 2026 or confront and justify it decision to deny non-EGUs this ability provided to EGUs.

Finally, the assertion that unit level controls are superior for non-EGUs because they are (in some unexplained way) "more administratively feasible and more easily implementable at the source level" is fatally inconsistent not just with EPA's prior findings, <u>but with the Proposed Rule itself</u>, which elsewhere expressly finds that an emission trading program is superior to direct controls for EGUs because "trading program's option to buy additional allowances provides flexibility in the program for outlier sources that may need more time than what is representative of the fleet average to implement these mitigation strategies while providing an economic incentive to outperform rate and timing assumptions for those sources that can do so. In effect this trading program implementation operationalizes the mitigation measures as state-wide assumptions for the EGU fleet rather than unit-specific assumptions."[108]

IX. Timing of Compliance for States Linked Only to Maintenance Receptors

EPA currently subjects states linked only with maintenance receptors[109] to the same 2026 deadline EPA sets as applicable to states linked to nonattainment receptors. But as explained below, this is based on an erroneous legal assumption that all compliance must be in place by 2026, when in fact EPA retains discretion with regard to states that are not linked to any nonattainment receptors. Furthermore, the 2026 deadline should not bind states only linked to maintenance areas, or in any case, requirements should be suspended as long as the linked receptors are in attainment, with obligations triggered only if the maintenance receptors slip into nonattainment, as explained below.

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[105] *Id.*

[106] *FCC v. Fox TV Stations, Inc.*, 556 U.S. 502, 515-16, 129 S. Ct. 1800, 1811 (2009).

[107] Clean Air Interstate Rule, 70 Fed. Reg. 25,161, 25,355 (May 12, 2005).

[108] Proposed Rule, pg. 20,100.

[109] I.e., Arkansas, Minnesota, Mississippi, Oklahoma, Wisconsin and Wyoming. See Air Quality Modeling TSD at D-1 to D-11.

The entire basis for the EPA selecting the 2026 ozone season compliance deadline for non-EGUs in the Proposed Rule is *Wisconsin v. EPA*'s requirement that EPA to tie upwind-State's Good Neighbor compliance to downwind-State's nonattainment deadlines or the earliest possible time thereafter, paired with EPA's finding that the 2026 ozone season is the first possible season during which the non-EGU limits proposed in the Proposed Rule can feasibly go into effect (which is aligned with the August 3, 2027, attainment date for areas classified as Serious nonattainment under the 2015 ozone NAAQS).[110]

But *Wisconsin* merely required "upwind States to eliminate their significant contributions in accordance with the deadline by which downwind States must come into compliance with the NAAQS."[111] And notably, this only requires linkage of deadlines when it is required for a downwind state to come into attainment, meaning that it does not govern maintenance receptors trending toward full attainment, such as the Brazoria County, TX receptor which EPA models to be in attainment before 2026 (i.e., where the receptor is in attainment, albeit maintenance, and thus the downwind state is in compliance with the NAAQS at that receptor such that no upwind reductions are needed by any specific time).

Accordingly, EPA's application of the 2026 deadline to states linked only to improving maintenance receptors (e.g., Arkansas, Minnesota, Mississippi, Oklahoma, Wisconsin, Wyoming) is legally erroneous, since EPA's current rationale is that such a deadline is mandated by *Wisconsin v. EPA*'s, when in fact it is not, and thus EPA must provide a discretionary rationale if it wishes to subject such states to the same deadline as states linked to nonattainment receptors.[112]

Additionally, it would be consistent with *Wisconsin v. EPA* to suspend applicability of the Proposed Rule's limits to Arkansas and Mississippi so long as the Brazoria County, TX receptor is in attainment by 2026, and EPA should do so given the specific characteristics and trend of the Brazoria receptor. As explained below, to truly link upwind state compliance deadlines to downwind compliance deadlines, EPA should suspend Good Neighbor compliance deadlines for states solely linked to a maintenance receptor unless and until such a maintenance receptor slips into nonattainment. After all, once the Brazoria receptor is no longer in nonattainment, Texas' obligations "to submit attainment demonstrations and associated RACM, RFP plans, contingency measures for failure to attain or make reasonable progress, and other planning SIPs related to attainment of the ozone NAAQS for which the determination has been made, *shall be suspended* until such time as: The area is redesignated to attainment for that NAAQS, at which time the requirements no longer apply; or the EPA determines that the area has violated that NAAQS, at which time the area is again required to submit such plans." [113] Thus, for example, it would be

[110] Proposed Rule at 20,099-100.

[111] *Wisconsin v. EPA*, 938 F.3d 303, 313 (D.C. Cir. 2019).

[112] See *Prill v. N.L.R.B*, 755 F.2d 941, 942 (D.C. Cir. 1985) (concluding that where an agency erroneously assumed that a determination was mandated and outside of the agency's discretion, the determination "stands on a faulty legal premise and without adequate rationale.").

[113] 40 CFR § 51.1318.

incongruous to require upwind emission reductions in 2026 based solely on contributions to the Brazoria County, TX if Texas' obligations with respect to the same receptor are suspended based on this receptor measuring in attainment by that time. This is especially justified for Arkansas given the upcoming closures of NOx sources like the White Bluff plant by 2028, leading to even further NOx reductions from Arkansas than taken into account by EPA.

Specifically for the Brazoria County, Texas receptor it is currently designated as marginal nonattainment, but EPA has proposed to redesignate it pursuant to CAA section 181(b)(2)(A)(i) and 40 CFR 51.1303 based on failure to attain by the deadline for marginal nonattainment, thus requiring the receptor to be attain the 2015 Ozone NAAQS by the next deadline of "no later than 6 years after the initial designation as nonattainment, which in this case would be no later than August 3, 2024"[114] EPA's modeling as part of the Proposed Rule models the Brazoria receptor reaching attainment (albeit maintenance status) by 2023 or before, expecting the receptor no longer be in nonattainment, such that Texas' obligations would be expected to be suspended with respect to that receptor at that time in 2024, and if Texas meets that attainment deadline as anticipated by EPA, the receptor could even be officially redesignated as no longer nonattainment before 2026 when the Proposed Rule's non-EGU limits are proposed to take effect. Thus, given the particular circumstances of the Brazoria receptor, including its specific deadline for attainment and EPA's modeling in the Proposed Rule, EPA should suspend applicability of the Proposed Rule's non-EGU limits on states linked solely to the Brazoria receptor so long as the Brazoria receptor is in attainment by the appropriate deadline. If, however, the receptor slips back into nonattainment after that time, then any necessary Good Neighbor provisions in states linked to that maintenance receptor would be triggered, with the provisions EPA currently proposes to be effective 2023 to instead become effective in the event the Brazoria receptor slips into nonattainment, with the provisions currently proposed for 2026 ozone season becoming effective three years from the date the Brazoria receptor actually slips to nonattainment.

X. Unreasonable Limitations on Public Comment

A. EPA Should Allow More Time for Public Comment

EPA is proposing to impose unprecedented unit-level emissions limitations on a wide array of industries and jurisdictions. There was virtually no effort to gather industry input prior to regulation, and as discussed above, little more effort has been made to review and incorporate data and comments from the states.

The Proposed Rule itself covers 181 pages, and the record still has numerous omissions. Yet EPA has provided only 11 weeks for public comment. While U. S. Steel appreciates the extension that extended the initial deadline by two weeks, this is still not enough time for proper public input on such an extensive attempt at regulation, and as noted throughout these comments, does not provide the time to perform the various analyses EPA failed to perform as part of the

[114] "Determinations of Attainment by the Attainment Date, Extensions of the Attainment Date, and Reclassification of Areas Classified as Marginal for the 2015 Ozone National Ambient Air Quality Standards" 87 Fed. Reg. 21,842, 21,850 (April 13, 2022).

Proposed Rule, including but not limited to facility- and unit-specific contribution modeling and facility- and unit-specific feasibility assessments, both of which must be prerequisites to any exercise of EPA authority under the Good Neighbor provision. To ensure an adequate process for public input, EPA must allow time for interested parties to analyze EPA's data and prepare supplemental information and comments.

B. EPA's Denial of U.S. Steel's Request for Additional Time for Comments is Unjustified.

U. S. Steel separately requested an additional extension (EPA-HQ-OAR-2021-0668-0244), which EPA denied on June 17, 2022. EPA's denial essentially relies on two grounds to deny the extension request. First, EPA relies on the claim that it must not further extend comments because EPA has an obligation to move "as expeditiously as practicable." But as noted in the State of Arkansas' comments on EPA's proposed denial of Arkansas' proposed Good Neighbor SIP provisions for the 2015 Ozone NAAQS, EPA delayed evaluation of underlying state SIP submissions and modeling for more than a year.[115] It is unreasonable for EPA to delay any evaluation of Good Neighbor provision requirements and then use that very delay as a reason to prevent the public from having adequate time to evaluate and comment on EPA's proposed approach. EPA's other rationale is that EPA provided some of the materials underlying the Proposed Rule prior to the formal publication of the Proposed Rule in the Federal Register. But this does not address the facts that (1) EPA's choice to pursue unit specific reductions entails requires detailed facility- and unit-specific modeling and engineering studies to evaluate contribution to downwind receptors and feasibility, availability, and cost of proposed controls, which can take months to complete in the detail necessary to fully evaluate the Proposed Rule's unprecedented limits that have never been achieved by any known source to date; and (2) that information needed to evaluate the Proposed Rule was not provided until after the Proposed Rule was published in the Federal Register. Simply re-running the CAMx modeling can take months and EPA took several weeks to provide the modeling data referenced in the Proposed Rule upon request, not providing the modeling files needed to adequately comment on EPA's modeling until over a month after publication of the Proposed Rule.

C. EPA Must Reissue the Rule For Additional Comment if Substantive Changes in Approach Are Made in the Final Rule.

The rulemaking procedures at section 307(d) of the CAA specifically require that a proposed rulemaking must "include a summary of—(A) the factual data on which the proposed rule is based; (B) the methodology used in obtaining the data and in analyzing the data; and (C) the major legal interpretations and policy considerations underlying the proposed rule" and "All data, information, and documents referred to in this paragraph on which the proposed rule relies shall be included in the docket on the date of publication of the proposed rule."[116] Furthermore,

[115] See Comment submitted by Arkansas Department of Energy and Environment, Division of Environmental Quality, on EPA-R06-OAR-2021-0801-0001, at 3-4 (April 22, 2022).

[116] 42 U.S.C. § 7607(d)(3).

any final "promulgated rule may not be based (in part or whole) on any information or data which has not been placed in the docket as of the date of such promulgation."[117] Relatedly, EPA has "an initial burden of promulgating and explaining a non-arbitrary, non-capricious rule" including an obligation to "explain how the standard proposed is achievable under the range of relevant conditions which may affect the emissions to be regulated."[118]

Accordingly, it would be unlawful for EPA to make any revisions to the Proposed Rule that are not supported by the data in the docket, including but not limited to subjecting additional units to the Proposed Rule where the feasibility, cost effectiveness, and significance to downwind receptors is not included in the docket supporting the Proposed Rule, absent a new proposed rule providing the opportunity for public comment on the basis for any such newly proposed changes. Furthermore, it would be arbitrary for EPA to reverse any of the determinations it has made in this Proposed Rule, such as by including emission units or sources not currently proposed to be included in the Proposed Rule or the draft regulation accompanying the Proposed Rule or imposing a trading system or other controls rather than the current proposed controls, without first re-issuing such changes in the form of a new proposed rule for additional public comment.

XI. EPA Should Reconsider the National Applicability of the Proposed Rule.

EPA proposes to find that this proposed action, "if finalized, would be 'nationally applicable' within the meaning of CAA section 307(b)(1)" or, in the alternative, that "this action is based on a determination of 'nationwide scope or effect" within the meaning of CAA section 307(b)(1)." This is based on EPA's finding that the "proposed action applies a uniform, nationwide analytical method and interpretation of CAA section 110(a)(2)(D)(i)(I) across these states, and the proposed rule is based on a common core of legal, technical, and policy determinations (as explained in further detail in the following paragraph). For these reasons, this proposed action is nationally applicable."[119].

EPA's proposal is not well founded. The Proposed Rule notes that if finalized, it will "implement the good neighbor provision in 26 states, spanning 8 EPA regions and 10 federal judicial circuits."[120] This is only because EPA has aggregated several rulemakings into the Proposed Rule. The FIP applies on a state-by-state basis. That EPA failed to make the state-specific assessments required for a proper review of each State's SIP and replacement with a FIP

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[117] 42 U.S.C. § 7607(d)(6)(C).

[118] *National Lime Ass'n v. E. P. A.*, 627 F.2d 416, 433 (D.C. Cir. 1980) (in the context of a new source performance standard rulemaking procedure subject to 42 U.S.C. § 7607(d), holding that "an initial burden of promulgating and explaining a non-arbitrary, non-capricious rule rests with the Agency and we think that by failing to explain how the standard proposed is achievable under the range of relevant conditions which may affect the emissions to be regulated, the Agency has not satisfied this initial burden."); *see also Nat. Res. Def. Council v. EPA*, 755 F.3d 1010, 1023 (D.C. Cir. 2014) ("EPA retains a duty to examine key assumptions as part of its affirmative burden of promulgating and explaining a nonarbitrary, non-capricious rule and therefore EPA must justify that assumption even if no one objects to it during the comment period.") (citation, internal question marks, and ellipses omitted).

[119] Proposed Rule at 20,168

[120] Proposed Rule at 20,168.

is not a justification for stripping the applicable regional courts of jurisdiction over what are inherently state-specific issues.

EPA's alternative approach, to find that the "proposed action is based on multiple determinations of nationwide scope or effect for purposes of CAA section 307(b)(1)" is similarly inadequate. Using a "common core of statutory and case law analysis, factual findings, and policy determinations concerning the transport of ozone-precursor pollutants from the different states subject to it, as well as the impacts of those pollutants and the impacts of options to address those pollutants in yet other states"[121] to find that a state-specific rule has national applicability is to find that the exception swallows the rule. Most state-specific rules EPA promulgates are based on a "common core of statutory and case law analysis, factual findings, and policy determinations." This is part of what prevents EPA from acting arbitrarily and capriciously. If this were sufficient to make a state-specific rule nationally applicable, then almost all EPA rulemaking would be forced into the D.C. Circuit for judicial review.

XII. Miscellaneous Comments, and Responses to EPA Requests for Comment

A. Applicability Provisions Require Clarification:

There are multiple aspects of the Proposed Rule's applicability which should be clarified before proceeding to final rule.

1. First, it appears that the Proposed Rule will only cover emission units which are individually under 100 tons per year in the case of facilities with a Basic Oxygen Process Furnace, for which the Proposed Rule would aggregate emissions from the "BOF Shop" for purposes of determining the Proposed Rule's applicability to units in the "BOF Shop."[122] EPA should further clarify what is unique about BOF operations that require them to be aggregated for applicability purposes rather than each emission unit being subject to a 100 tpy applicability threshold like other furnaces. Furthermore, because the Proposed Rule does not contain any NOx emission standard applicable to a BOF Shop as a whole, and because the activities listed as constituting a BOF appear to include activities that are not one of the furnace types regulated under the Proposed Rule (e.g. hot metal transfer and desulfurization), and because the processes noted as constituting a BOF Shop do not appear to be the type of activities that each have separate stacks, the final rule should clarify how a BOF Shop will demonstrate compliance with the emissions in the rule (e.g., if all emissions in a BOF Shop are vented through the same venting system, then a BOF Shop should be able to aggregate the individual limits of any units within the BOF Shop in making its compliance demonstration, or should be subject to a separate overall limit for a BOF Shop).
2. The definition of a reheat furnace as currently drafted is overly vague and should be amended to match the reheat furnaces (and related definitions) on which EPA's review was

[121] Proposed Rule at 20,168

[122] Proposed Rule at 20,181.

based. The current definition of a reheat furnace in the Proposed Rule is "a furnace used to heat steel product to temperatures at which it will be suitable for deformation and further processing."[123] This definition does not define what counts as "steel product" (e.g., does it include only products that have already been manufactured into some form prior to being introduced to a reheat furnace, or does it include steel that has never left the original production process, such as hot steel coming directly from a connected casting process which has not yet been formed into a definitive product). When setting a limit for reheat furnaces in the Proposed Rule, EPA expressly relied on the Ohio RACT limit for reheat furnaces.[124] Ohio's applicable definition (i.e. defining the universe of units the RACT limit EPA relied on applied to) provides that " 'Reheat furnace' means a furnace in which metal ingots, billets, slabs, beams, blooms and other similar products are heated to bring them to the temperature required needed for hot-working."[125] This definition is also consistent with the various permits that EPA looked at when setting a limit for a reheat furnace.[126] EPA should likewise clarify its definition of reheat furnace to match the definition used by Ohio or otherwise make the definition more clearly limited to the types of units and limits EPA considered in setting the emission limits for reheat furnaces in the Proposed Rule. This clarification should more clearly differentiate a reheat furnace, which handles pre-made intermediate products, from something like a tunnel furnace that merely maintains and equalizes the temperature of raw already-hot-slabs while in transit from a caster to some other operation like a rolling mill. Any other approach that broadens applicability of the definition of reheat furnace beyond the type of sources EPA reviewed in setting its proposed emission limit would be arbitrary, since it would be unreasonable and arbitrary to regulate a unit without any reasoned basis for subjecting it to that emission limit.

3. EPA should also resolve the current discrepancy concerning the basis for the 40% reduction EPA is requiring at reheat furnaces. The Proposed Rule states that a 40% reduction is assumed based on installation of SCR,[127] whereas the underlying Non-EGU Sectors TSD states that the 40% reduction is instead based on low-NOx burners, not including SCR.[128] Either way, EPA must also provide additional rationale for the reductions, because assuming reductions based solely on the basis of low NOx burners may be inconsistent with the fact that the permit limits EPA reviewed in setting this limit, specifically Sterling Steel, already had low-NOx burners installed, and thus it may not be reasonable to assume

[123] Proposed Rule at 20,181.

[124] Non-EGU Sectors TSD at 42.

[125] OAC 3745-110-01 (35).

[126] See Non-EGU Sectors TSD at 42, pointing to permit limits at Sterling Steel, Charter Steel, and United States Steel Lorain Tubular Operations, each of which specifies a premade product that the reheat furnace accepts as an input, i.e. a "Billet" reheat furnace at Sterling Steel, a "Bar Mill" reheat furnace at Charter Steel. Likewise, the US Steel Lorain Tubular facility reheat furnaces handle products made elsewhere as inputs and are not handling raw product.

[127] Proposed Rule at 20,145.

[128] Non-EGU Sectors TSD at 43.

additional emission reduction since those controls are already in place. By contrast, if the reductions are based on assumption of SCR feasibility, then EPA must detail why EPA believes SCR to be feasible and cost effective for such units, which it has not done specifically to reheat furnaces.

4. The Proposed Rule should clarify what if any limit is applicable to galvanizing furnaces. The Non-EGU Sectors TSD mentions galvanizing furnaces several times, often in the same context as annealing and reheat furnaces, such as when EPA identifies a Wisconsin NOx RACT limit of 0.08 lb/mmBtu which applied to reheat, annealing and galvanizing furnaces.[129] Furthermore, the technical support document also distinguishes between reheat, annealing, and galvanizing furnaces as separate types of units.[130] However, the final rule includes different limits for annealing furnaces (0.06 lb/mmBtu) and reheat furnaces (0.05 lb/mmBtu), and does not include a separate galvanizing furnace limit. Accordingly, EPA should clarify whether galvanizing furnaces are intended to be included under the limits applicable to reheat furnaces, annealing furnaces, or neither, including appropriately detailed rationale.

B. The Proposed Rule's Emission Unit Specific Limits and Monitoring Requirements Will Not be Practicably Enforceable for Units that Lack Unit Specific Stacks.

The Proposed Rule appears to assume that each different unit is stacked such that its emissions could be disaggregated from other units, but that is not the case. Some units share a joint stack, some have multiple stacks, and some are so minor as to not be stacked. Accordingly, the Proposed Rule, if finalized, must allow for flexibility in demonstrating compliance with associated emission limits.

For example, the Proposed Rule establishes separate limits for EAFs, LMFs, and ladle/tundish preheaters. But LMFs and ladle/tundish preheaters are relatively small sources of emissions at the U. S. Steel's BRS facility (and future EV facility) are not vented through a separate stack. Rather, the EAF and LMF and other small units in the melt shop such as ladle/tundish preheaters are typically hooded and exhausted through the same canopy system to the baghouse where the joint emissions then vent to the baghouse and the primary exhaust stack. Accordingly, it is not possible to separately monitor preheater, LMF, and EAF emissions with CEMS, or to verify separate emission limits, since any compliance demonstration, whether by CEMS or stack testing, will necessarily be based on a joint measurement of preheater, LMF, and EAF emissions. This is reflected in BRS's and EV's current air permits, which provides a joint lb/hr emission limit for an LMF and EAF combined. Accordingly, to the extent the final rule still imposes command-

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[129] Non-EGU Sectors TSD at 42.

[130] Non-EGU Sectors TSD at 26 ("Annealing involves a supplemental heating process to change the hardness properties of the final steel produced and ensure homogeneity. The galvanizing process coats iron or steal in a coating of molten zinc to protect and seal, limiting rust and corrosion. Reheat furnaces are used in hot rolling mills to heat steel slabs for rolling into sheets").

and-control limits for individual emission units, the final rule should take this reality into account by either creating a joint limit for an EAF, LMF and preheaters combined, or by allowing EAF, LMF, and preheater emissions to be aggregated for purposes of any compliance demonstration of their combined limits. Furthermore, EAFs are the only units that are over 100 tpy at U. S. Steel BRS and EV facilities subject to the Proposed Rule, and thus the Proposed Rule would not apply to LMF and preheaters, at least at these facilities. Thus, EPA should clarify how compliance with the proposed emission limits for EAFs will be demonstrated, given the fact that any CEMS installed on an EAF stack will reflect emissions from other units which may not even be subject to limits under the Proposed Rule.

By contrast, other units like the tunnel furnaces at the BRS facility have as many as five stacks per furnace due to the physical length of the tunnel transportation process. It cannot be assumed that these could be redesigned to a single stack, because due to design and overlapping influence within the tunnel furnaces the atmospheric conditions as it relates to the burners can potentially have different requirements for one stack versus another and could adversely affect the facility and steel quality. Accordingly, when performing cost estimates to determine the appropriateness of any efficiency limits EPA proposes for such furnaces, EPA must take into account the cost of multiple SCR and CEMS rather than assuming that a single CEMS and SCR could be installed on such units. For clarity, these units have less than 100 tpy NOx potential emissions at the U. S. Steel BRS facility, and as noted in the previous comment, it is unclear whether a tunnel furnace designed solely to maintain temperatures of hot-steel would in any-case be covered by the Proposed Rule.

Finally, annealing units can vary greatly in size and amenability to controls. For example, the batch annealing furnaces at the U. S. Steel BRS facility (and the EV facility under construction) entail such small amounts of emissions that they are not stacked and thus cannot be subjected to unit specific SCR, much less CEMS.

C. Efficiency Based Form of Proposed Emission Limits is Unreasonable

EPA provides no persuasive justification for imposing efficiency limits (i.e., lb/mmBtu limits) instead of emission limitations tied to the actual reductions needed to eliminate an upwind state's significant contribution. EPA's statutory authority under the Good Neighbor provision is solely intended to be used to reduce an absolute "amount" of emissions for the tailored purpose of achieving downwind NAAQS attainment[131], and is not an appropriate means to force industrywide standards of performance; if the efficiency standards preferred by EPA can be justified, then EPA can pursue that objective through NESHAP and NSPS standards. Furthermore, EPA's modeling relied on estimates of tons of reductions expected throughout each state, and EPA's compliance method is a CEMS, both of which are directly linked to absolute emissions, rather than emission efficiency. Finally, mandating efficiency-based limits arbitrarily and unreasonably eliminates the option for affected facilities to achieve any required emission reductions during ozone season through reduced operations, which could be just as effective at achieving any reductions needed

[131] 42 U.S. Code § 7410(a)(2)(D)(i)(I).

to achieve any obligations under the Good Neighbor provision. A lb/mmBtu limit puts affected facilities, especially those with higher-than-average retrofit costs in a challenging situation, forced to choose between infeasible costs, or being shut down altogether. By contrast, limits like those that EPA has proposed in the past which only require statewide reductions by the amount emissions modeled to eliminate an upwind state's significant contribution would at least provide owners of such facilities with a tenable option of reducing emissions through reduced utilization during ozone season short of complete shutdown.

D. Unit Specific Nature of Limits Fails to Consider Alternate Emission Reductions

The unit specific nature of the proposed efficiency limits eliminates facility flexibility in reducing overall NOx emissions in more technically feasible and cost-effective ways. Although the Proposed Rule continues to grant EGUs some limited flexibility in figuring out how best to reduce emission to meet limits (which in some cases includes complete facility shutdown), the Proposed Rule robs non-EGUs of the same flexibility. Different facilities face different design and operational limitations, and the operators of each facility are in the best position to assess how to maximize emission reductions while minimizing process impacts. For example, in cases where installation of controls on an applicable furnace is not feasible, facilities should instead have the flexibility to achieve the same level of emission reductions through other means, for example a facility may still have the option of low NOx optimizations on units that would otherwise not be subject to the Proposed Rule, such as furnaces or boilers that are not of sufficient size to be included under the Proposed Rule.

E. Climate Change is Not Carte Blanche to Tighten Regulations and NAAQS Without Notice and Comment

EPA makes a generalized appeal to climate change as an excuse to find that Arkansas, Mississippi, and Wyoming are not overcontrolled by the Proposed Rule, despite EPA's models suggesting they are overcontrolled, because "future ozone concentrations and the formation of ground level ozone, may be impacted by climate change in future years," and relying on uncertainty rather than even attempting to model any climate change effect.[132] But "where an agency is uncertain about the effects of agency action, it may not rely on 'substantial uncertainty' as a justification for its actions. Instead, it must 'rationally explain why the uncertainty' supports the chosen approach."[133] And handwaving about uncertainties associated with climate change is not an excuse for increasing control stringency by overcontrolling emissions under the Good Neighbor provisions of the Clean Air Act, which are focused solely on NAAQS, absent proper regulatory and statutory authorization.[134]

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[132] E.g., Proposed Rule at 20,099.

[133] *Scholl*, 489 F. Supp. 3d at 1036.

[134] To the extent EPA is attempting to use climate change considerations to make the 2015 Ozone NAAQS more stringent without going through the rulemaking process to revise the 2015 Ozone NAAQS. Any attempt by USEPA to do so in the context of the Proposed Rule would not be consistent with EPA legal obligations under the CAA.

F. It Would be Arbitrary for EPA to Not Include Waste Incinerators in the Final Rule If Other Non-EGUs Are Included

The current draft of the Proposed Rule does not propose to regulate (1) EGUs less than or equal to 25 MW, (2) solid waste incineration units, and (3) cogeneration units, each of which, just like the Iron and Steel industry and all other non-EGUs, have traditionally been excluded from EPA's interstate air transport programs. [135] Accordingly, any potential emission reductions from such facilities were not included when EPA estimated state-by-state potential NOx reductions under the Proposed Rule. [136] But EPA also requested comment on whether these must be included, and specifically noted that EPA is "considering whether to include emissions limitations for solid waste incineration units" in the Final Rule.[137]

It would be arbitrary for EPA to require reductions at the proposed non-EGUs, but not include waste incinerators. By EPA's own analysis, such waste incinerators emissions can be an order of magnitude larger than the applicability limits EPA is using to subject other industries like steel mills to command-and-control limits.[138] The questions EPA requests comment on when EPA considers whether to include waste incinerators in the final rule are generally valid questions (e.g., feasibility and cost effectiveness of controls). But EPA's resulting position is incorrect.

For example, there are potentially many such units in Arkansas, including units with permitted NOx emissions at least as high as steel industry units, and far closer to the Brazoria TX receptor than U. S. Steel's BRS and EV facilities.[139] In the Proposed Rule, EPA seeks to impose emission limits on non-EGUs such as EAFs without providing any analysis of technical feasibility

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[135] Proposed Rule at 20,084.

[136] Non-EGU Screening Assessment at 1 n.1.

[137] Proposed Rule at 20,084.

[138] Non-EGU Sectors TSD at Table 8.

[139] The following facilities, are not an exclusive list, but includes various incineration facilities under NAICS codes 562213(Solid Waste Combustors and Incinerators) or 562211 (Hazardous Waste Treatment and Disposal): Elemental Environmental Solutions LLC, Arkadelphia, 1016-AOP-R15, (245.7tpy NOx), https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/1016-AOP-R15.pdf; Clean Harbors LLC, El Dorado, 1009-AOP-R24 (535.7tpy NOx), https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/1009-AOP-R24.pdf. Furthermore, the following facilities are registered under General Air Permit for Title V Air Curtain Incinerators, which permits up to 30.6 tpy of NOx based on up to 15,300 tons of waste incinerated at the air curtain incinerator per rolling 12-month period (https://eportal.adeq.state.ar.us/webfiles/Air/General%20Permits/2370-AGP-000.pdf): City of Jonesboro - Yard Waste Facility (6.75 tons burned per hour); City of Dardanelle (4 tons per hour burned); Woodson Incorporated, Mabelvale (8 to 10 tons burned per hour); City of Blytheville Public Works (3 to 5 tons burned per hour); Wise Excavation LLC, Paron (8 tons burned per hour); Abide Farms, LLC, Little Rock (7 tons burned per hour); American Composting, Inc., North Little Rock (7 tons burned per hour); R. E. C. Transport, Inc., Dardanelle (7 tons burned per hour); Alternative Waste Management LLC., Mayflower (9 tons burned per hour); Arkansas Department of Transportation, Paragould (0.125 tons burned per hour); Custom Wood Recycling, Inc., Centerville (12 tons burned per hour); City of Wynne Air Curtain Incinerator (10 tons burned per hour); Columbia County Landfill, Magnolia (unspecified throughput); City of Beebe (7.5 tons burned per hour); Dale Payne - P & P Trucking, Casa (8 tons burned per hour); Moore's Dozer Service, Glenwood (9 tons burned per hour).

or cost effectiveness in the record. Yet for solid waste incineration units, EPA is proposing to use those very same factors to potentially exclude waste incinerators. If waste incinerators are excluded on such grounds, EAFs, and the many other units EPA failed to analyze for technical feasibility or cost feasibility must also be exempted. In addition, it is worth noting that any decision by EPA in the final rule to include such units (e.g., EGUs less than or equal to 25 MW, solid waste incineration units, and cogeneration units), would require EPA to perform a reanalysis of overcontrol, since including such units without adjusting the required control limits at other facilities could further exacerbate overcontrol resulting from the Proposed Rule.

G. Controls Will Only be Run on a Seasonal Basis

EPA requested comment on whether any controls installed in order to meet the limits in the Proposed Rule would be run on an annual basis.[140] As a general rule, post combustion controls like SCR will not be operated year-round. As noted above, facilities will only run post-combustion NOx controls during the ozone season when required to and will otherwise limit their use due to the high O&M cost associated with operation of the SCR, and in order to attempt to extend the life of the catalyst given the high cost of replacing the catalyst and how quickly the catalyst can be deactivated under the process characteristics of metal furnaces. Low NOx burners, the other hand, would be operated on a year-round basis since they are integrated into the combustion process.

H. Alternatives to CEMS

EPA requested comment on alternatives to CEMS for ensuring compliance.[141] There are many alternatives to CEMS. For boilers and burner tips, especially, vendor guarantees and known engineering emission factors for natural gas combustion can be used to simply and far more cost effectively track emissions based on simply tracking natural gas usage/throughput. This method may also work for furnaces where NOx emissions derive primarily from coal or natural gas combustion. For any other sources whose NOx emissions cannot be simply derived by tracking natural gas or coal throughput, stack testing should be available as an alternative means of compliance.

More fundamentally, EPA has not demonstrated that CEMS are necessary and appropriate as a means of tracking emissions for non-EGUs. The authority to require any monitoring device must be justified under 42 U.S. Code §7410(a)(2)(B), which states that an implementation plan shall "provide for establishment and operation of *appropriate devices*, methods, systems, and procedures *necessary to*—(i) monitor, compile, and analyze data on ambient air quality." In the past, EPA has required CEMS under Good Neighbor provision implementation plans on the rationale that such precise continuous measurements are necessary when implementing an emission trading program, because as EPA puts it "[t]his type of consistent and accurate measurement of emissions is necessary to ensure each allowance actually represents one ton of emissions and that one ton of reported emissions from one source would be equivalent to one ton

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[140] Proposed Rule at 20,141.

[141] Proposed Rule at 20,146.

of reported emissions from another source."[142] But the Proposed Rule expressly decides not to implement a trading program, instead purporting to opt for unit specific performance limits for non-EGU emission units. Moreover, EPA did not even include the cost of CEMS in its cost analysis.[143] Accordingly, EPA has failed to justify both why CEMS are "appropriate" and why they are "necessary" in this wholly different context of unit specific performance rates, especially in light of the fact that other programs (NSPS, NESHAP, PSD, etc.) merely require initial performance testing and periodic confirmatory testing to verify unit specific performance limits, and that EPA wholly fails to provide any persuasive differentiation here in the absence of emission trading.

XIII. The Proposed Rule Endangers National Security by Failing to Consider the Steel Industry's Critical Role in Our National Security and Infrastructure:

A 2017 Presidential Memorandum recently acknowledged that "core industries such as steel" as "critical elements of our manufacturing and defense industrial bases."[144] As a result of the Memorandum, the Department of Commerce initiated an investigation into the effect of steel imports on United States National Security and found that domestic steel production is "essential" for national security applications.[145] This Investigation led to many key findings that the EPA should consider as it evaluates how to effectuate the requirements of the Good Neighbor provision in a reasonable manner.

"[A]cross decades and Administrations, there has been consensus that domestic steel production is vital to national security."[146] "National security" under Section 232 of the 1962 Trade Expansion Act includes both 1) national defense and 2) critical infrastructure needs.[147] Domestic steel production is vital for both. For example, the Department of Defense requires steel to create weapons and other systems needed for our nation's defense.[148]

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[142] Proposed Rule at 20,141 (citing 75 FR 45325 (August 2, 2010)).

[143] Non-EGU Screening Assessment at 4 ("The costs do not include monitoring, recordkeeping, reporting, or testing costs.").

[144] DCPD-201700259 - Memorandum on Steel Imports and Threats to National Security, § 1 (Apr. 20, 2017) (available at https://www.govinfo.gov/content/pkg/DCPD-201700259/pdf/DCPD-201700259.pdf).

[145] U.S. Dep't. of Commerce, *The Effect of Imports of Steel on the National Security: An Investigation Conducted Under Section 232 of the Trade Expansion Act of 1962*, (hereinafter, "2018 Investigation"), Jan. 11, 2018 (available at https://www.commerce.gov/sites/default/files/the_effect_of_imports_of_steel_on_the_national_security_-_with_redactions_-_20180111.pdf).

[146] *Id.* at p. 24.

[147] *Id.* at p. 13–17, 23 (concluding that domestic steel production is essential for national security); *see also* 19 U.S.C. § 1862 (Section 232 of the Trade Expansion Act of 1962).

[148] 2018 Investigation at p. 24.

Presidential Policy Directive 21 ("PPD-21") also designates sixteen "critical infrastructure sectors," most of which use steel in high volumes.[149] This includes chemical production, communications, critical manufacturing, dams, energy, food production, nuclear reactors, and transportation, water, and wastewater systems. To support these critical infrastructure sectors, the American Society of Civil Engineers estimated that the United States must invest $4.5 trillion in infrastructure by 2025.[150] Steel production is crucial to these goals.

An important consideration to maintaining national security is ensuring that there is sufficient "surge capacity" within the industry, as explained by the Department of Commerce, "it is the ability to quickly shift production capacity used for commercial products to defense and critical infrastructure production that provides the United States a surge capability that is vital to national security, especially in an unexpected or extended conflict or national emergency."[151]

But as written, the Proposed Rule blinks these realities in ways that would have potentially catastrophic consequences for the economy and national security. Even assuming that it was possible to meet the Proposed Rule's unprecedented command-and-control limitations on NOx, installing the required control technologies will cause at least temporary closures of iron and steel facilities all around the nation all at once. "Even temporary idling of steel plants threatens the U.S. steel industry" because of the "significant financial costs with re-opening a steel mill."[152] Halting production can also cause a mill to lose workers, which affects the mill's capacity to produce steel going forward.[153] This often leads to additional costs, such as "specialized worker training and production ramp-up" while mills attempt to re-fill their workforce.[154] And that is the best case scenario; if these newly proposed limits are not feasible, and/or not able to be achieved cost effectively, mills could be forced to permanently close. Even if the new limits are attainable by some facilities, the Proposed Rule's inflexible and uniform command-and-control mandate fails to consider facility specific feasibility and cost variability and thus will likely result in permanent closures, crippling U.S. surge capacity.

Employment and local economies are likewise negatively affected when steel mills are closed, even on a temporary basis. Workers often find other occupations, steel mills to work at, or they remain indefinitely unemployed.[155] If a closure lasts a significant amount of time, workers may lose some of the specialized skills needed for performance. This loss of workers, jobs, and

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[149] PPD-21 can be viewed at https://obamawhitehouse.archives.gov/the-press-office/2013/02/12/presidential-policy-directive-critical-infrastructure-security-and-resil.

[150] 2017 Infrastructure Report Card, American Society of Civil Engineers, https://www.infrastructurereportcard.org/wp-content/uploads/2016/10/2017-Infrastructure-Report-Card.pdf.

[151] 2018 Investigation at p. 55-56.

[152] 2018 Investigation at p. 34.

[153] *Id.* at 35.

[154] *Id.*

[155] *Id.*

skills causes substantial difficulties to the steel industry, as recruitment is "typically not easy."[156] And any further workforce constriction would be especially impactful because workforce experience in the iron and steel sector are already diminished.

Further, U.S. steel producers already experience higher production costs than those in other areas of the world. This is, in part, because of environmental and regulatory expenses.[157] For example, prices for hot-rolled steel coil have been higher in the United States than in other countries since 2010.[158] These higher costs incentivize foreign importation of steel, which damages steel production in the United States.

The Proposed Rule will cause iron and steel facilities to temporarily shut down while they attempt to comply with the proposed limits that have never been achieved in practice at any similar units, and thus, even if feasible, will almost certainly result in downtime as facilities and control devices are redesigned and tested. EPA's proposed compliance deadline of the 2026 ozone season risks mass temporary closures of steel mills across the country and across regions. And the supply chain disruptions arising from Covid and subsequent economic conditions, which EPA has not accounted for in setting compliance deadlines, feasibility, or cost analyses, will exacerbate the disruptions to operations that would be caused by these retrofits even in the best of times. This will hinder much of the aforementioned categories: domestic steel production will slow, local economies will be hurt, costs will rise, and the industry may lose skilled workers. Overseas imports of steel will necessarily increase, assuming there is availability. In addition, it is well known fact that steel producers in the United States have far less emissions than most sources overseas that would have to be relied on to make up for the capacity drop in domestic steel production caused by the Proposed Rule.[159] EPA must consider these critical issues as it assesses how to reasonably give effect to the Good Neighbor provision, including taking care in evaluating whether it is actually necessary to regulate the iron and steel industry in order to achieve the reductions needed to satisfy the Good Neighbor provision, and if so whether there are measures with more flexibility (including emission trading, and extended compliance deadlines) rather than rushing into draconian command-and-control measures without any evaluation of facility specific feasibility. Failure to do so threatens to jeopardize our nation's steel industry, infrastructure, and national security.

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[156] *Id.*

[157] *Id.* at p. 33.

[158] *Id.* at p. 31–33.

[159] See e.g. Hasanbeigi, Ali and Cecilia Springer. "How Clean is the U.S. Steel Industry? An International Benchmarking of Energy and CO2 Intensities." Global Efficiency Intelligence (November 2019), available from the Harvard's Belfer Center for Science and International Affairs at https://www.belfercenter.org/sites/default/files/files/publication/how-clean-is-the-us-steel-industry-nv.pdf, (concluding that "The U.S. steel industry's final energy and CO2 emissions intensities rank 4th lowest among the countries studied" and showing that the U.S. steel industry is the cleanest and most energy-efficient of the seven largest steel producing countries in the world).

SPECIFIC COMMENTS PERTAINING TO ELECTRIC ARC FURNACES AND ARKANSAS

XIV. EPA Has Identified No Legal Basis for Imposing Emission Unit Specific Limits on the U.S. Steel Facilities in Arkansas.

As discussed in Sections above EPA has no legal basis for regulating U. S. Steel facilities especially those in Arkansas. Notably, the *only* impact relied on for subjecting specifically Arkansas and Mississippi to the stringent non-EGU emission limits in the Proposed Rule is a single maintenance receptor in Brazoria County, Texas which EPA classifies as maintenance status, and projects to still be in maintenance status in 2026. See *Air Quality Modeling Technical Support Document* at D-1 & D-6. The fact that EPA has presented no analysis to support a conclusion that emission units at the U. S. Steel Arkansas facilities (which are located in Osceola, Arkansas, on the far opposite end of the state from TX, about 560 miles from Brazoria, Texas) contribute significantly to impacts at the Brazoria receptor is alone sufficient to require the exclusion of those facilities from the Proposed Rule. But for the sake of thoroughness, U. S. Steel requested the experienced air modeling team at Woodard & Curran to perform modeling to evaluate the significance of BRS's (and EV's, once it commences operation) contribution, if any, to the Brazoria receptor linked to Arkansas under EPA's modeling as demonstrated in the Woodard Report attached as Exhibit A.

First, Woodard & Curran evaluated the impact of BRS/EV on Brazoria based on the scaling factors used by EPA to evaluate the anticipated contributions of industry sectors in developing the Proposed Rule, including the emission units sought to be regulated under the Proposed Rule. More specifically, Woodard updated the emission inventory used by EPA to more accurately reflect the existing BRS facility and the EV facility under construction adjacent thereto,[160] then extrapolated BRS/EV's contribution to the Brazoria receptor using EPA's own state and receptor specific factors, as explained in Woodard and Curran's report. As noted in Table 3 to that report, EPA's calculation methodology would result in an estimate of less than 0.01 ppb contribution from BRS/EV to the Brazoria receptor. This is below the level of significance that EPA used to evaluate the significance of iron and steel facilities to individual receptors (0.01 ppb), and thus is insignificant even by EPA's own interpretation. Moreover, as explained in more detail in a subsequent comment, significance of impacts at a receptor should not be evaluated below 1 ppb, which is far higher than that calculated for BRS/EV. Finally, this calculation method is highly

[160] The BRS scrap to steel products facility in Osceola, Arkansas currently contains two Electric Arc Furnaces (EAFs), which are the only emission units at the facility with a potential to emit more than 100tpy of NOx. On January 31, 2022, AEEDEQ issued BRS a permit to construct and operate a new scrap to steel mill on land adjacent to the existing facility. BRS anticipates transferring the permit for the new mill to Exploratory Ventures (EV), a separate company, but which, like BRS, is owned by US Steel. Although this second facility is not integrated with and operates independently from the existing mill, BRS/EV understands that under existing EPA guidance, the two mills would be considered a single source under Title I of the Clean Air Act. Like the existing facility, the new facility will also have two EAFs, each with a potential to emit more than 100tpy of NOx. The new facility provided notice to AEEDEQ on May 12, 2022, of commencement of construction. Accordingly, the Woodard & Curran model conservatively accounts for all four EAFs in evaluating any potential impact on the Brazoria receptor.

conservative, since the extrapolation factors used in EPA's calculation do not account for where in a state a source is located, and BRS/EV is located in the far edge of the state, over 900 km from the Brazoria receptor.

Second, Woodard & Curran performed HYSPLIT modeling in coordination with AEEDEQ to evaluate impacts to the Brazoria monitor. EPA itself used HYSPLIT in this rulemaking to evaluate environmental justice impacts on a facility specific level for EGUs[161] (though EPA did not use it to evaluate EPA's authority to regulate individual facilities under the Proposed Rule in the first place). EPA has also previously approved the use of HYSPLIT to screen out areas in the similar context of regional haze.[162] HYSPLIT looks at the specific events during which ozone NAAQS exceedances are predicted and can generate a backtrajectory to identify what geographic regions airflows contributed to each specific predicted NAAQS exceedance. This provides more insight than the CAMx model into specific contributions on the specific days that EPA relies on to classify the Brazoria receptor as a maintenance receptor (especially the way that EPA ran CAMx, evaluating only aggregated statewide contributions in general without tagging industries or facilities like CAMx would have allowed EPA to do if EPA had attempted to do so).

HYSPLIT analysis also provides insight as to whether any potential linkages identified by CAMx are consistent and persistent.

EPA's CAMx modeling only looked at five to ten elevated ozone days and did not evaluate where the ozone and precursors arose that contributed to those days (i.e., although EPA looked generally to what states may have contributed, EPA did not evaluate or identify where in a given state contributions originated, since EPA chose to run CAMx without source tags).

To evaluate whether the U. S. Steel facilities in Arkansas could contribute to any of these ozone high events identified by EPA, Woodard & Curran used HYSPLIT to calculate seventy-two hour back-trajectories for the EPA's top-ten CAMx predicted maximum daily 8-hour 2026 ozone events for the ozone monitoring site located in Brazoria, TX. As noted in Woodard & Curran's attached report, the top three ozone days had contributing air parcels originating well outside of Arkansas, or only briefly passing through the very southern section of Arkansas, and in no event originated or passed through the northeastern portion of Arkansas where the U. S. Steel facilities are located. As a result, the U. S. Steel Arkansas facilities did not contribute to any of the events assessed by EPA, and thus cannot be said to significantly contribute to any maintenance issues evaluated by EPA at the Brazoria receptor.

Woodard & Curran is also in the process of performing confirmatory CAMx modeling to determine the source specific contributions to the Brazoria monitor which EPA neglected to evaluate. As EPA is aware, CAMx modeling can take significant time to complete, and although we are diligently pursuing this modeling, it is impossible to complete before the June 21 comment deadline. However, because the necessity of this modeling was created by EPA's failure to perform

[161] Policy Analysis TSD at 67.

[162] 87 Fed. Reg 7734 (Feb 10, 2022).

and/or disclose source-specific CAMx contribution modeling and unreasonably truncated public comment period, and because it bears directly on EPA's authority to regulate U. S. Steel at all under the Good Neighbor provision, EPA must consider this modeling whenever it is completed in determining applicability of any final rule to U.S. Steel facilities without running afoul of the Clean Air Act.[163]

XV. EPA Has Identified No Legal Basis for Regulating the Iron and Steel Industry in Any But Possibly One State, and Certainly Not in Arkansas

EPA has not demonstrated that the Iron and Steel industry in Arkansas (or virtually any state for that matter) is a "type of emissions activity within the State" that will "contribute significantly to nonattainment in, or interfere with maintenance by, any other State."

To begin, as previously noted, EPA's regulation of the iron and steel industry in Arkansas did not even comply with EPA's own oft-referenced "4-step interstate transport framework." Under that approach, EPA, after identifying nonattainment and maintenance receptors (step 1), and screening out any state not contributing at least 0.7ppb to any linked receptor (step 2), was then supposed to "(3) for states linked to downwind air quality problems, identify [] upwind emissions that significantly contribute to downwind nonattainment or interfere with downwind maintenance of the NAAQS; and (4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind areas, implement[] the necessary emissions reductions through enforceable measures."[164] But that is not what EPA did in the Proposed Rule. Rather than evaluate the upwind emissions actually contributing to each screened-in state's linked nonattainment or maintenance receptors, EPA instead just (1) identified industries *nationwide* that contributed at least 0.1pbb to at least one downwind receptor, or 0.01pbb to at least ten receptors[165]; and (2) automatically mandated limits directly on all such sources in each screened-in state, skipping any finding that these sources evaluated on a nationwide basis actually contributed to nonattainment or interfered in maintenance at the linked receptors for each particular state.[166]

Although it may be appropriate as a screening matter to initially identify industry sectors representing potentially significant NOx contributions on a national basis for further review, EPA cannot automatically skip to imposing regulations on all such industry sectors in all screened-in states without some showing that the industry sector at issue is significantly contributing to that particular state's linked nonattainment or maintenance receptors. This is because the Good Neighbor provision from which EPA derives any authority for such regulations only grants authority to prohibit emissions if a "type of emissions activity *within the State*" will "contribute

[163] In fact, using CAMx to simply repeat the modeling that USEPA performed takes longer than the comment deadline allows, particularly in light of how long EPA took to supply the underlying modeling data upon request.

[164] Proposed Rule at 20,041-42.

[165] EPA classified industries that satisfied both these criteria as "Tier 1" and those that satisfied only one as "Tier 2."

[166] Non-EGU Screening Assessment at 2-3, 22-23.

significantly to nonattainment in, or interfere with maintenance by, any other State."[167] Thus, it is arbitrary and capricious to regulate the steel industry nationally rather than regulating the appropriate sources (or at least appropriate industrial sectors) in each state actually contributing to the amount of emissions that need to be reduced from that state to fulfill its Good Neighbor obligations.

EPA also improperly conflated its own screening threshold for whether a state as a whole has a significant enough contribution to require reductions pursuant to the FIP, with the statutory requirement to evaluate significant contributions of a "source or type of emissions activity within the State." As the State of Arkansas rightly notes in it comments in response to EPA's proposed denial of Arkansas' proposed state implementation plan for the 2015 Ozone NAAQS as it relates to Good Neighbor obligations, EPA wholly failed "to show that specific sources in Arkansas are actually contributing significantly to the Harris County monitor or interfering with maintenance of the NAAQS by other receptors, thus EPA is effectively contending that a 1% linkage is the same as a significant contribution, which is not consistent with their guidance or Clean Air Act 110(a)(2)(D)(i). Determination of linkages and significant contributions occurs at separate steps in the four-step analysis. DEQ does not agree that a 1% linkage to an entire state is the same as a significant contribution from a source or emissions activity. The state's obligation is not to eliminate an arbitrary threshold (or to reduce emissions such that a neighboring state that may be its own primary contributor to nonattainment is not overburdened by their own obligations), but to determine if any emissions sources or emissions activity in the state are significantly contributing to a downwind nonattainment receptor or interfering with maintenance of the NAAQS by a downwind state and respond accordingly to mitigate significant contributions."[168]

If EPA had failed to evaluate the contributions of each screened-in industry in a state prior to subjecting it to regulation in that state, then EPA would have 'merely' failed to justify the regulation of such industry in each state. But EPA's failure to comply with statutory requirements is even more unreasonable, arbitrary, and unlawful here, because it appears that EPA *did* perform an evaluation of whether each industry contributed to nonattainment or maintenance issues at each states linked receptors, and then went on to attempt to regulate NOx emissions from each industry sector in each screened-in state despite specifically finding that many industries did not contribute to that state's linked receptors above the industry significance thresholds set by EPA.[169] For instance, EPA's own modeling found that the Iron and Steel industry only contributed to a nonattainment or maintenance receptor above EPA's own significance threshold (0.01ppb) in only one state and that state is not Arkansas, as show below[170]:

[167] 42 U.S. Code § 7410(a)(2)(D)(i)(I).

[168] See Comment submitted by Arkansas Department of Energy and Environment, Division of Environmental Quality, on EPA-R06-OAR-2021-0801-0001, at 22 (April 22, 2022).

[169] See Table A-3 to Non-EGU Screening Assessment.

[170] See Table A-3 to Non-EGU Screening Assessment.

Table A-3. Estimated Total, Maximum, and Average Contributions from Each Industry, and Number of Receptors with Contributions >= 0.01 ppb for 2023

Industry	# Facilities with Units > 100tpy	# Units > 100 tpy	Ozone Season Emissions	Total Contribution	Max Contribution	Average Contribution	# Receptors with Contributions >= 0.01 ppb	# States with Highest Contribution >= 0.01 ppb
Pipeline Transportation of Natural Gas	144	399	34,343	1.679	0.287	0.084	12	12
Cement and Concrete Product Manufacturing	61	84	36,244	1.871	0.231	0.094	19	13
Iron and Steel Mills and Ferroalloy Manufacturing	14	43	4,622	0.577	0.129	0.029	11	1
Basic Chemical Manufacturing	38	78	9,612	0.293	0.123	0.015	9	2
Glass and Glass Product Manufacturing	38	53	12,059	0.695	0.105	0.035	11	7
Petroleum and Coal Products Manufacturing	47	94	8,163	0.733	0.098	0.037	12	6
Metal Ore Mining	9	21	17,778	0.687	0.079	0.034	15	3
Lime and Gypsum Product Manufacturing	31	60	8,856	0.531	0.066	0.027	13	3
Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing	16	27	3,680	0.162	0.044	0.008	3	1
Pulp, Paper, and Paperboard Mills	46	73	6,773	0.306	0.043	0.015	11	3
Oil and Gas Extraction	59	139	9,150	0.207	0.035	0.010	9	2
Nonmetallic Mineral Mining and Quarrying	8	18	3,808	0.167	0.035	0.008	4	1
Resin, Synthetic Rubber, and Artificial and Synthetic Fibers and Filaments Manufacturing	10	16	1,779	0.152	0.027	0.008	7	2
Other Chemical Product and Preparation Manufacturing	7	8	683	0.074	0.024	0.004	3	1
Clay Product and Refractory Manufacturing	1	2	1,098	0.088	0.024	0.004	4	1
Chemical and Allied Products Merchant Wholesalers	1	4	573	0.032	0.019	0.002	2	1
Natural Gas Distribution	6	17	1,027	0.058	0.016	0.003	1	1
Water, Sewage and Other Systems	6	6	375	0.069	0.016	0.003	4	1
Pharmaceutical and Medicine Manufacturing	2	2	300	0.057	0.011	0.003	1	1

Although Table A-3 does not disclose the sole state with impacts from the iron and steel industry above EPA's significance thresholds for industry, the context suggests that state is almost certainly not Arkansas, as those are not among the states where the Non-EGU Screening Assessment identifies large potential reductions of NOx from the iron and steel industry.**171** Thus, EPA's own modeling appears to affirmatively demonstrate that Iron and Steel Industry is NOT a significant contributor to Arkansas' downwind linked maintenance receptor (Brazoria), and it would thus be arbitrary and unlawful for EPA to subject the steel industry in Arkansas and other such states to the Proposed Rule in the face of this specific finding. The same conclusions could be reached for the iron and steel industry in every other state without further analysis with the exception of the single state identified by EPA in the Proposed Rule.

It is particularly important for EPA to correct this approach given its determination that Arkansas may be overcontrolled under the Proposed Rule since their contributions to the Brazoria receptor are predicted to be erased based solely on imposition of controls on Tier 1 industry.[172]

EPA's request for comments on whether to only regulate Tier 1 industries in Arkansas and exempt Tier 2 industries also misses the statutory mark. EPA only has regulatory authority to prohibit amounts of emissions from a "source or other emissions activity" that will "contribute significantly to nonattainment in, or interfere with maintenance by, any other State." Thus, for Arkansas, EPA must consider whether an industry is actually a significant contributor to Arkansas' linked receptors, and it is arbitrary and unlawful for EPA to consider regulating an industry in Arkansas on some other basis (such as whether EPA considers an industry to be "Tier 1" or "Tier 2" as a nationwide matter). For instance, EPA's modeling suggests that for Arkansas, Pipeline Transportation of Natural Gas (a so called "Tier 1" industry) and Pulp, Paper, and Paperboard Mills (a so called "Tier 2" industry) are by far the industries where most of the emission reductions are expected to occur in Arkansas under the Proposed Rule, with potential reductions from Pulp, Paper, and Paperboard Mills dwarfing the amount of all other Tier 1 industries combined (other

[171] See Non-EGU Screening Assessment at Figure 2 (identifying only IN, OH, and PA as having ozone season anticipated NOx reductions of more than 100 tons).

[172] Proposed Rule at 20,099.

than "Pipeline Transportation of Natural Gas").[173] Accordingly, EPA should avoid overcontrol and adhere to the statutory text by only regulating industries within a particular state which significantly contribute to that state's linked receptors, rather than by whether EPA happens to classify the industry as "Tier 1" or "Tier 2" on a nationwide basis.

XVI. There are Many Reasons to Conclude that the Proposed Rule Will Result in Impermissible Overcontrol, Specifically With Regard to Arkansas.

The Supreme Court has held that when drafting regulations to enforce the Good Neighbor provision, "EPA cannot require a state to reduce its output of pollution by more than is necessary to achieve attainment in every downwind State or at odds with the 1% threshold the Agency has set" . Moreover, "if any upwind State concludes it has been forced to regulate emissions below the one percent threshold or beyond the point necessary to bring all down-wind States into attainment, that State may bring a particularized, as-applied challenge to the Transport Rule, along with any other as-applied challenges it may have." Notably, these pronouncements were made in the context of an EPA rule which placed statewide emission budgets on states (thus allowing states to challenge those emission budget) and did not impose facility/emission unit level command-and-control limits like the Proposed Rule. By the same rationale, because the Proposed Rule attempts to impose facility/emission unit level command-and-controls on the purported basis of such controls being necessary to fulfill Good Neighbor provisions, the Proposed Rule will be subject to facility level challenges from any facility on the basis that EPA's controls are more stringent than necessary to result in attainment of any downwind receptor to which the facility's state is linked. Accordingly, EPA's statement that any "claim that controls are not necessary to eliminate significant contribution would not suffice to justify an extension" is false; not only would such a claim justify an extension, but it should completely exempt such facilities from the Proposed Rule's limits altogether, since the Good Neighbor provision only grants authority to prohibit emissions "in amounts which will . . . contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard."

There are many reasons to believe that the Proposed Rule results in impermissible overcontrols, especially with regard to the Brazoria County, Texas receptor which is the only receptor Arkansas is linked to, and thus the only basis EPA has identified for imposing non-EGU limits in Arkansas.[174]

A. Brazoria Receptor Resolves Without Any Reductions from Arkansas and Mississippi.

To begin, the Brazoria County, TX receptor is a maintenance receptor, not a nonattainment receptor. To be sure, the courts have held that the Good Neighbor provision grants authority to prohibit not just amounts that will contribute significantly to nonattainment, but also those amount

[173] Non-EGU Screening Assessment at Table 4.

[174] While U.S. Steels comments in this section is limited to Arkansas, the same arguments could be made as it relates to the State of Mississippi, which is also linked solely to the receptor in Brazoria County, Texas.

that significantly "interfere with maintenance." However, "As the Supreme Court stated, under the 'interfere with maintenance' prong, EPA may only limit emissions 'by just enough to permit an already-attaining State to maintain satisfactory air quality.' If States have been forced to reduce emissions beyond that point, affected parties will have meritorious as-applied challenges."[175]

Brazoria is not just modeled to be a maintenance receptor; it is modeled to consistently improve and to be full attainment and non-maintenance before 2032, as shown below in EPA's own modeling values predicted for the Brazoria receptor in the absence of the Proposed Rule[176]:

Site ID	*ST*	*County*	*2016 Centered Avg*	*2016 Centered Max*	*2023 Avg*	*2023 Max*	*2026 Avg*	*2026 Max*	*2032 Avg*	*2032 Max*
480391004	TX	Brazoria	74.7	77	70.1	72.3	69.1	71.2	67.7	69.8

This is notably different from the scenario addressed by the D.C. Circuit in *Wisconsin v. EPA*, 938 F.3d 303, 326-27 (2019), when the court rejected a generalized argument that a state is necessarily overcontrolled if it is linked to only maintenance receptors yet subjected to the same control levels as states linked to nonattainment receptors. In the first place, that court rejected the claim before it because it was generalized, rather than alleging an as-applied challenge to a specific instance of overcontrol, and because the rule at issue in that case was not expected to fully satisfy upwind States' Good Neighbor responsibilities.[177] But neither of those apply here, to this particularized instance of overcontrol at the Brazoria receptor, in the context of a Proposed Rule designed to fully satisfy upwind States' Good Neighbor responsibilities. Additionally, the court in *Wisconsin* noted that ''the possibility of failing to maintain the NAAQS in the future, even in the face of current attainment of the NAAQS, is exactly what the maintenance prong of the Good Neighbor provision is designed to guard against.''[178] But here, by contrast, the Brazoria County, Texas receptor is not modeled to continue to be a maintenance monitor in danger of slipping to nonattainment, instead it is modeled to trend in the opposite direction, going out of maintenance into full attainment without any application of the Proposed Rule.[179] For this specific receptor, it would thus result in overcontrol to require the draconian NOx reductions required in the Proposed Rule for the states linked only to this receptor.

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[175] *EME Homer City Generation, L.P. v. E.P.A.*, 795 F.3d 118, 137 (D.C. Cir. 2015) (quoting *EPA v. EME Homer City Generation, L.P.*, 572 U.S. at 515 n.18).

[176] Air Quality Modeling Technical Support Document at Appendix B, B-3.

[177] *Wisconsin v. EPA*, 938 F.3d 303, 327 (2019).

[178] *Wisconsin v. EPA*, 938 F.3d 303, 326 (2019) (quoting 81 Fed. Reg. at 74,531).

[179] Note also that this conclusion is not affected by potential future industrial growth in upwind states, both because EPA already accounted for anticipated future emission inventory changes, and because any new major sources must undergo PSD evaluations to ensure they do not adversely affect any NAAQS compliance.

B. EPA's Modeling Significantly Underestimates Reductions Associated with the Proposed Rule, Instead Demonstrating that Downwind Linked Receptors are Resolved by Significantly Less Stringent Non-EGU Controls than the Proposed Rule

As explained in more detail below, the modeling used to conclude that the Proposed Rule does not result in overcontrol, specifically at the Brazoria receptor, is based on estimated reductions from each covered non-EGU sector in each state which are far smaller than the emission reductions that would be imposed by the limits in the Proposed Rule. Because EPA's screening assessment shows that sources in Arkansas can reduce emissions sufficiently to bring the Brazoria receptor into full attainment without consideration of numerous excluded facilities (including U. S. Steel's BRS and EV facilities) and without installing SCR on any EAF or other emission units at iron and steel facilities in Arkansas, EPA's decision to nonetheless require stricter emission controls than modeled, on more facilities than modeled, means that the Proposed Rule's emissions limits must result in overcontrol. And because there is substantial overcontrol in Arkansas, all the Proposed Rule's emission limits on non-EGUs (including U. S. Steel's BRS and EV facilities) are arbitrary and capricious because there is no way to determine which limits are necessary to avoid interference with maintenance at the Brazoria receptor.

More specifically, the Proposed Rule relies on the non-EGU Screening Assessment as the basis for the Proposed Rule's evaluation of reductions associated with the Proposed Rule.[180] But EPA drafted this screening assessment before it had performed the air quality modeling underlying the Proposed Rule, and as a result, used a different emission inventory than the emission inventory prepared for the rest of the Proposed Rule.[181] The docket includes a technical support document dedicated to explaining that the non-EGU Screening Assessment was not even designed to capture the facilities that would actually be subject to the Proposed Rule.[182] In EPA's words "Using the emissions thresholds and other factors laid out in the Screening Assessment, EPA generated a preliminary list of non-EGU facilities and emissions units to inform the development of the Proposed Rule. The list of non-EGU facilities and emissions units generated during the Screening Assessment did not constitute a determination by EPA that the identified non-EGU facilities and emissions units are covered by the Proposed Rule. The information on facilities and emissions units provided in the Screening Assessment is likely not a complete listing of the non-EGU

[180] Proposed Rule at 20,056 ("Section III of the Non-EGU Screening Assessment memorandum in the docket for this rulemaking describes EPA's approach to evaluating impacts on downwind air quality, considering estimated total, maximum, and average contributions from each industry and the total number of receptors with contributions from each industry.").

[181] Non-EGU Screening Assessment at 2 n.2 ("We used the [Revised CSAPR Update] air quality modeling for this screening assessment because the air quality modeling for the Proposed Rule was not completed in time to support this assessment.").

[182] See "Technical Memorandum Describing Relationship between Proposed Applicability Criteria for Non-EGU Emissions Units Subject to the Proposed Rule and EPA's 'Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026'" (Memo re Relationship of Proposed Rule to Screening Assessment).

facilities and emissions units potentially covered by the Proposed Rule." In other words, when EPA performed its modeling to evaluate potential emission reductions, EPA did not include the facilities that would be subject to the Proposed Rule, nor the limits that would actually apply to the emission units at those sources.

As a result, this "preliminary list of non-EGUs" notably omits many facilities that would be impacted by the Proposed Rule, and significantly underestimates the emission reductions from some it does include. For instance, in Arkansas, the Non-EGU Screening Assessment included a single emission unit at Nucor-Yamato as the only unit evaluated from the Iron and Steel industry, resulting in reductions of only 6 ozone season tons (15tpy) estimated from the entire iron and steel industry in Arkansas.[183] This absurdly underestimates the reductions that the Proposed Rule would require in Arkansas alone for multiple reasons:

- Even at the one steel mill in Arkansas included in the non-EGU Screening Assessment, the Nucor unit is listed as having annual NOx emissions of only 19tpy.[184] But given that the screening assessment claims to only evaluate emission units with a potential to emit over 100tpy of NOx, this is an error (whether a typo, a selection of the wrong unit at the facility or otherwise). Either way, the Proposed Rule would decrease the permitted lb/ton NOx rate for this facility's (Nucor) EAFs from the current permit limit of 0.38 lb/ton[185] to the Proposed Rule limit of 0.15 lb/ton (i.e., a 0.23 lb/ton reduction). At an average steel production rate of 500 tons per hour[186] times 3,672 hours per ozone season,[187] that represents a potential reduction of up to 422,280 lb (i.e. 211.14 ozone season tons) from this facility's EAFs alone;
- Furthermore, the screening assessment completely omits the existing U. S. Steel's BRS facility (despite the fact that EPA was surely aware of it since EPA used the facility permit as one of the bases for the Annealing Furnace lb/mmBtu limit in the Proposed Rule).[188] At BRS alone, the Proposed Rule would decrease the permitted lb/ton NOx rate for each of the facility's two EAFs by up to 50%, by reducing the current permit

[183] See excel file titled "Screening Assessment Non-EGU Facility and Emission Unit Limits List," which states that "This file provides the list of facilities in 23 states that EPA evaluated in the Technical Memorandum: Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026."; see also non-EGU Screening Assessment at Figure 2 (estimating a total of 1,654 ozone season tons NOx reduction from Arkansas, only 6 of which come from the Iron and Steel industry in Arkansas for) and compare also Proposed Rule at 20,090 (carrying through the non-EGU Screening Assessment without further analysis).

[184] See excel file titled "Screening Assessment Non-EGU Facility and Emission Unit Limits List".

[185] See Nucor-Yamato Steel Company permit no. 0083-AOP-R17, available at https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/0883-AOP-R17.pdf

[186] See Nucor-Yamato Steel Company permit no. 0083-AOP-R17 at 3.

[187] 153 days in Ozone Season of May-September times 24 hours per day.

[188] Proposed Rule at 20,145.

limit of 0.3 lb/ton[189] to the Proposed Rule limit of 0.15 lb/ton. At a presumed capacity of 250 tons/hr each,[190] times 3,672 hours per ozone season,[191] that represents a reduction of up to 275,400 lb (i.e. 137.7 ozone season tons) from the facility's two existing EAFs alone;[192]

- U. S. Steel's BRS and Nucor-Yamato are just two of the four Iron and Steel facilities in Arkansas identified by EPA in the modeling used to develop a base case for the Proposed Rule.[193] Accordingly, the screening assessment wholly ignored the reductions the Proposed Rule would force at those other facilities as well.

Notably, this underestimation issue applies beyond Arkansas as well; in fact only one U.S. Steel facility nationwide was accounted for in the screening assessment at all.[194]

By contrast, EPA did include many sources that were not included in the non-EGU Screening Assessment (including U. S. Steel's BRS facility) when later modeling the base case of emissions for the Proposed Rule.[195] *The net result is that EPA accounted for NOx emission from the U. S. Steel BRS* facility when it collectively estimated the impacts of Arkansas as a whole on the Brazoria County, Texas receptor, but not when calculating the reductions expected from non-EGUs from Arkansas as a result of the Proposed Rule. The only conclusion that can be reached is that EPA significantly underestimates the reductions that the Proposed Rule would require.[196] And the fact that this underinclusive modeling was used as the basis for concluding that the Proposed Rule does not result in overcontrol renders EPA's conclusions regarding overcontrol both in general, and especially with respect to Arkansas, arbitrary and capricious.

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[189] See Big River Steel Permit No. 2305-AOP-R7, available at https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/2305-AOP-R7.pdf

[190] Big River Steel Permit No. 2305-AOP-R7, at 68.

[191] 153 days in Ozone Season of May-September times 24 hours per day.

[192] As noted, other units, including most notably the LMF, vents to the same canopy as the EAF, and U. S. Steel's BRS facility air permit provides a combined lb/hr rate for each EAF/LMF combination. Accordingly, the amount of emission reductions expected by the rule will in some part depend on whether facilities are required to show decreases from an EAF alone (which is not technically feasible given that any CEMS in the exhaust will be measuring combined emissions of the EAF and LMF), or instead allows compliance to be demonstrated based on the sum of the proposed limits for EAFs and LMFs or some other mechanism. But in any case, the emission reductions would be far above those estimated in the non-EGU Screening Assessment.

[193] See excel file in regulatory docket titled "Summaries of point source emissions used in aqm _att 4 - ptnonipm facility 16 17 18 19 23 26 32 comp 29sep2021".

[194] See excel file in regulatory docket titled "Screening Assessment Non-EGU Facility and Emission Unit Limits List," (identifying only the Clairton Works facility in Allegheny County PA).

[195] See excel file in regulatory docket titled "Summaries of point source emissions used in aqm _att 4 - ptnonipm facility 16 17 18 19 23 26 32 comp 29sep2021" (listing NOx emissions for BRS facility for 2017, 2018, and 2019).

[196] This assumes for the sake of argument that the reductions required by the Proposed Rule are even possible, as addressed herein under the section regarding feasibility.

Rather than take the next step and attempt to estimate what reductions would be associated with the Proposed Rule's command-and-control limits for the iron and steel industry, EPA instead just used the statewide emission reductions from the severely underinclusive non-EGU Screening Assessment as the basis for EPA's estimate of state-by-state expected NOx reductions, which then formed the basis of EPA's conclusion that the rule does not result in overcontrol.[197] Put another way, it appears that EPA's own modeling concluded that even the severely underestimated non-EGU emission reductions would be sufficient to pull the Brazoria County, Texas receptor into attainment.[198] Accordingly, if EPA nonetheless requires the emission limits in the Proposed Rule, which will result in reduction in NOx emissions far above what EPA modeled to result in attainment for the Brazoria receptor (only 6 ozone season tons), EPA is overcontrolling in violation of the Supreme Court's mandate that "under the 'interfere with maintenance' prong, EPA may only limit emissions 'by just enough to permit an already-attaining State to maintain satisfactory air quality.'"[199]

C. The Proposed Rule Fails to Account for Enforceable Closures of EGUs Which Will Result in Overcontrol if Non-EGUs in Arkansas to Subjected to Regulation

EPA fails to account for enforceable closures of multiple EGU units in Arkansas, which, as explained below, will eliminate more NOx contribution from the State of Arkansas than the entirety of all reductions the Proposed Rule seeks from Arkansas. Accordingly, requiring the Proposed Rule's limits for non-EGUs on top of these closures will result in overcontrol.

The following three Entergy power plants are subject to closure pursuant to settlement agreements soon after the 2015 Ozone NAAQS serious attainment deadline of August 2027, and years before the final attainment date under the 2015 Ozone NAAQS of August 2033 for severe nonattainment[200]:

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[197] Proposed Rule at 20,098 ("using the Ozone AQAT, the EPA first evaluated whether reductions resulting from the selected control stringencies for EGUs in 2023 and 2026 combined with the emissions reductions selected for non-EGUs in 2026 can be anticipated to resolve any downwind nonattainment or maintenance problems (see the Ozone Policy Analysis Proposed Rule TSD for details on the construction and application of AQAT)."); see also Policy Analysis TSD at 34, noting that for non-EGUs, *estimated reductions at receptors was based on the non-EGU assessment* ("In the ozone AQAT, EPA links state-by-state NOX emission reductions (derived from the photochemical model, the non-EGU assessment and/or the IPM EGU modeling combined with the EGU engineering assessment) with 2026 CAMx modeled ozone contributions in order to predict ozone concentrations at different levels of emission levels at monitoring sites.") (emphasis added); *see also* Proposed Rule at 20090 (carrying through the non-EGU Screening Assessment estimates of state-by-state potential NOx reductions without further analysis);

[198] Non-EGU Screening Assessment at Table 3 (concluding that Tier 1 industry reductions estimated from the Screening Assessment alone would result in attainment for Brazoria receptor); see also 20,098 (parroting result of underinclusive Screening Assessment with regard to the Brazoria Receptor).

[199] *EME Homer City Generation, L.P. v. E.P.A.*, 795 F.3d 118, 137 (D.C. Cir. 2015) (quoting *EPA v. EME Homer City Generation, L.P.*, 572 U.S. at 515 n.18).

[200] https://www.arkansasonline.com/news/2021/mar/12/in-settlement-power-plants-to-shut-by-30/

- 50-year-old natural gas units at Lake Catherine by the end 2027 (permitted for 53,000tpy of NOx,[201] actual 2019 ozone season emissions of 173 tons[202])
- Coal-fired White Bluff Power Plant by the end of 2028 (permitted for 53,000tpy of NOx,[203] actual 2019 ozone season emissions of 2,908 tons[204])
- Coal-fired Independence Power Plant by the end of 2030 (permitted for 53,000tpy of NOx,**205** actual 2019 ozone season emissions of 2,845 tons[206]).

Notably, in the Proposed Rule, EPA found that the Proposed Rule constitutes a full satisfaction of Good Neighbor obligations based on only 1,654 *total statewide* ozone season tons reduction from non-EGUs in Arkansas.[207] Accordingly, the closure of White Bluff alone in 2028 or earlier will reduce statewide emissions by almost double the amount that EPA considers sufficient to resolve Arkansas' Good Neighbor obligations, making any control of non-EGUs at that point an impermissible overcontrol unnecessary to satisfy Arkansas' Good Neighbor obligations.

Furthermore, these facilities are much closer to the Brazoria County, Texas and are more likely to interfere with that receptor than are the U. S. Steel BRS and EV facilities.

Although these enforceable closures are not scheduled to occur prior to EPA's proposed 2026 deadline for non-EGUs to comply with the Proposed Rule, that is not a reasonable excuse for failing to take them into account, at least with respect to Arkansas, for at least two reasons.

1. As further discussed herein in the comment section on timing, EPA's selection of a compliance deadline of 2026 is based on deadlines applicable to downwind nonattainment regions, and thus it is not necessary or reasonable to require the same deadline where only attaining maintenance receptors are affected, as is the case with Arkansas which is linked solely to the Brazoria County, Texas receptor, which as previously discussed above, is predicted to be in attainment (but still maintenance) by

[201] Permit available at https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/1717-AOP-R9.pdf

[202] See EPA's power plant dataviewer (most recent data from 2019), available at https://www.epa.gov/airmarkets/power-plant-data-viewer

[203] Permit available at https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/0263-AOP-R16.pdf

[204] See EPA's power plant dataviewer (most recent data from 2019), available at https://www.epa.gov/airmarkets/power-plant-data-viewer

[205] Permit available at https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/0449-AOP-R17.pdf

[206] See EPA's power plant dataviewer (most recent data from 2019), available at https://www.epa.gov/airmarkets/power-plant-data-viewer

[207] Proposed Rule at 20,090.

2023, to improve even further by 2026, and be full attainment (i.e., no longer maintenance) by or before 2032.[208]

2. The Proposed Rule suggests exempting EGUs from the backstop daily rates otherwise applicable to EGUs in 2026, so long as the EGUs close by 2028,[209] effectively treating 2028 as the effective compliance deadline where EGU closures are concerned.[210] EPA raises many good reasons for considering 2028 given the many changes relevant to air quality that will occur in 2028, including EGU closures in response to new Clean Water Act effluent guidelines and the coal combustion residuals rule under the Resource Conservation and Recovery Act, and the fact that "2028 also represents the end of the second planning period under the Regional Haze program, and thus is a significant year in states' planning of strategies to make reasonable progress towards natural visibility at Class I areas." [211] Notably, EPA proposes to allow EGUs to postpone limits until 2028 even in states actually tied to a nonattainment downwind receptor (unlike Arkansas), which are under an obligation to resolve their linkage by the time of downwind states' attainment deadline pursuant to *Wisconsin v. EPA*.[212] Given all of these emission reductions anticipated in 2028, and EPA's consideration of these factors in postponing compliance deadlines from 2026 to 2028 in the context of EGU closures, EPA should also take into account closures anticipated by 2028 (including the White Bluff plant in Arkansas) in evaluating the need to regulate non-EGUs.

Given the fact that EPA already identified changes in 2028 as reasonable to consider in setting compliance obligations (including even for States that are predicted to have impacts on nonattainment areas beyond 2026), the fact that Arkansas is not linked to any nonattainment receptor that requires an obligation to resolve the linkage by the time of the downwind state's attainment deadline, and the fact that the closure of White Bluff Power Plant in 2028 would alone eliminate more emissions than EPA models are needed from all non-EGUs combined in Arkansas to ensure attainment at the Brazoria receptor, it would constitute impermissible overcontrol of the Brazoria receptor to subject non-EGUs in Arkansas to the Proposed Rule.

XVII. EPA Fails to Demonstrate that the Proposed Limits and the Theoretical Controls They are Based on Are Technically Feasible.

[208] Air Quality Modeling Technical Support Document at Appendix B, B-3.

[209] EPA's flexibility around the 2026 deadline for EGUs also extends to facilities which will not shut down in 2028, as EPA proposes to not require unit specific backstop emission rates until 2027 for facilities that do not already have SCR installed. See Proposed Rule at 20,111-12.

[210] Proposed Rule at 20,122.

[211] Proposed Rule at 20,122.

[212] Notably even EPA relies on not being required to achieve the impossible. See Proposed Rule at 20062 ("implementing good neighbor obligations beyond the dates established for attainment may be justified on a proper showing of impossibility or necessity.").

As explained above in Section II., when applying RACT, which Congress has made the express determination is the appropriate level of control when addressing Ozone NAAQS nonattainment, and which EPA claims it meant to follow in developing the Proposed Rule, EPA must demonstrate that the proposed limits are both technically and economically feasible on a facility and unit specific basis. And even stricter standards like BACT still require an analysis of technical and economic feasibility. And in any case, EPA has an independent "duty to examine [and justify] key assumptions as part of its affirmative 'burden of promulgating and explaining a non-arbitrary, non-capricious rule. . . .'"[213] and EPA may not "promulgate rules on the basis of inadequate data, or on data that, to a critical degree, is known only to the agency."[214] And thus EPA's assumptions regarding feasibility in the Proposed Rule must be adequately justified.

The comments in this section are specifically tailored to EAFs because those are the only furnaces used at U. S. Steel's Arkansas facilities with a potential to emit more than 100tpy of NOx, and thus are the only units the Proposed Rule would apply to, since the Proposed Rule only aggregates emissions for the purposes of applicability in the case of a BOF Shop (which would not apply to an EAF given that EAFs and BOFs are different processes, as noted throughout these comments, and throughout the Proposed Rule and its supporting materials). If EPA changes course in the final rule and expands the applicability of the limits in the Proposed Rule, we reserve our right to challenge such applicability and/or provide additional comments regarding any other such units EPA may extend applicability to. In any case, many of the following comments also apply to the other furnace types covered by the rule since EPA has not conducted an adequate feasibility analysis for any iron and steel industry emission unit sought to be regulated under the Proposed Rule.

A. The Controls EPA Bases the Proposed Iron and Steel Industry Emission Limits on Have Never Been Demonstrated in Practice, and EPA's Analysis of Feasibility is Provides Zero Basis to Conclude that They Could be Technically Feasible.

EPA expressly acknowledges that the emission limits for the iron and steel industry, including but not limited to furnaces, are below anything that has ever been achieved in the industry, expressly noting that EPA reviewed permits to find the best performing sources, then requires reductions below what the most stringent existing permits require. The only basis EPA provides for assuming that such reductions are possible is that EPA "[a]ssumes 25% reduction by SCR" for steel mill EAFs.[215] But none of EPA's underlying documentation or data ever evaluate the technical feasibility of retrofitting SCR on steel mill EAFs, or the level of emission reductions available from such a retrofit on an EAF. Simply put, not everything is equivalent to a coal-fired powerplant even though EPA's technical support document incorrectly makes that assumption.

With regard to the technical feasibility of installing an SCR on an EAF, the Proposed Rule does not point to any steel mills that have successfully installed SCRs on an EAF, nor is U.S. Steel

[213] *Appalachian Power Co. v. EPA*, 328 U.S. App. D.C. 379, 135 F.3d 791, 818 (1998).

[214] *Portland Cement Ass'n v. Ruckelshaus*, 158 U.S. App. D.C. 308, 486 F.2d 375, 391-93 (1973).

[215] Proposed Rule at 20,145.

aware of any EAF facility to have successfully done so in the world (and there are good reasons for this, as explained in the following subsection).[216] The BRS facility underwent PSD review in 2013 and the new EV facility underwent PSD review in 2021. BACT analyses were submitted with both applications. EPA provided comments on the draft BRS permit in 2013 but did not comment on the 2021 application. In both instances, the application of SCR was eliminated from consideration because the technology is not technically feasible. Other PSD permits issued to EAFs in recent years, all subject to review and comment by EPA, reach similar conclusions. Furthermore, EPA has specifically concluded in the past that "the use of electricity to melt steel scrap in the EAF transfers NOx generation from the steel mill to a utility power plant. *There is no information that NOx emissions controls have been installed on EAF's or that suitable controls are available*."[217]

EPA is required to "provide a more detailed justification than what would suffice for a new policy created on a blank slate" when it promulgates a "new policy [which] rests upon factual findings that contradict those which underlay its prior policy" and an "Agency may not . . . depart from a prior policy sub silentio."[218] There can be little question that the Proposal both departs from prior positions without rationale, and contradicts factual findings underlying its prior policies:

1. EPA abandons its own edict that each unit must be assessed "on an individual basis to determine whether SCR is a feasible control technology"[219]—EPA has not provided any feasibility analysis for steel mill EAFs generally, let alone for each EAF "based on its site-specific characteristics." In fact, the very document which the Proposed Rule cites as the basis for concluding that SCR will reduce emissions from EAFs[220] expressly states that "This screening assessment is not intended to be, nor take the place of, a unit-specific detailed engineering analysis that fully evaluates the feasibility of retrofits for the emissions units, potential controls, and related costs. We used CoST to identify emissions units, emissions reductions, and costs to include in a proposed FIP; however,

[216] In connection with the preparation of these comments, U.S. Steel consulted extensively with SMS Group, which is one of the world's leading suppliers of technology in the iron and steel industry and is the main technology provider for EAFs and other steelmaking equipment at U.S. Steel's BRS and EV facilities. According to the SMS Group, it is aware of no facilities in the world where SCR technology has been installed to control NOx emissions from steel mill EAFs. Black and Veatch's discussion with SCR vendors confirms this conclusion.

[217] Alternative Control Techniques Document – NOx Emissions From Iron and Steel Mills (EPA-453/R-94-065) (September 1994), at pg. 5-23; See also Point and NonPoint NOx Menu of Control Measures, at 15-16 (2012) (only identifying post combustion NOx controls as feasible for certain furnace types in the iron and steel industry, but not for electric arc furnaces). Note that there are natural gas burners used to assist the process, but these are responsible for less than 30% of the NOx emissions associated with an EAF, with the bulk of emissions being associated with the electric arc process, which is not a combustion process. Furthermore, the burners used are already low-NOx such that further emission reductions from burner replacements cannot be assumed to be feasible.

[218] *FCC v. Fox TV Stations, Inc.*, 556 U.S. 502, 515-16, 129 S. Ct. 1800, 1811 (2009).

[219] EPA Comments to Cost Estimate Manual, SCR Chapter, pg. 9, 13-14.

[220] Proposed Rule at 20,146 citing the "non-EGU screening assessment" as the basis for estimated "reductions of 20 to 50 percent" for iron and steel mills.

CoST was designed to be used for illustrative control strategy analyses (e.g., NAAQS regulatory impact analyses) and not for unit-specific, detailed engineering analyses."[221]

2. EPA has not provided any justification for its newfound belief that SCR is a feasible control for steel mill EAFs. Specifically, the Proposed Rule does not detail what if any relevant change to EAF or SCR technology has occurred since 1994 which would make SCR technically feasible NOx control for an EAF. [222]
3. EPA has historically refused to adopt unproven applications of technologies even in other programs where EPA has broad authority to require NOx reductions.[223]

Despite these past practices and findings, EPA nonetheless skips any analysis of unit specific feasibility, or even technical feasibility for EAFs in general, while nonetheless imposing limits that expressly presuppose such feasibility.

With regard to emission reductions expected, the Proposal purports to base its assumption of "reductions of 20 to 50 percent" for iron and steel mills "on the selection of SCR, SNCR, and burner replacement in the non-EGU screening assessment."[224] But the non-EGU screening assessment never assessed emission reductions associated with installation of an SCR at a single EAF.[225] And for newer facilities like U.S. Steel's BRS or EV facilities, which have undergone BACT review in recent years, low NOx burner technology is already in place. EPA does not explain or acknowledge this disconnect and provides no other rationale for why an SCR (or other technologies) can be assumed to reduce NOx emissions on an EAF by more than 20%-50%. Because the Proposed Rule's assertion that steel mill EAFs can achieve required emission limits by installing SCRs or other technologies is unsupported by the screening assessment on which EPA purports to base its assumptions, the Proposed Rule is arbitrary and capricious since "the agency has failed to 'examine the relevant data' or failed to 'articulate a rational explanation for its actions.'"[226] Nor does EPA attempt any facility or emission unit level analysis of whether the

[221] Non-EGU Screening Assessment at 7.

[222] Alternative Control Techniques Document – NOx Emissions From Iron and Steel Mills (EPA-453/R-94-065) (September 1994), at pg. 5-23.

[223] E.g., "Acid Rain Program; Nitrogen Oxides Emission Reduction Program," 61 Fed. Reg. 67,112, 67,151 (December 19, 1996) (In the context of setting NOx emissions under the Title IV Acid Rain program, finding "The AEP demonstration of retrofitting a two-stage OFA system to a wet bottom boiler has not proved to be successful as yet. Thus, EPA does not find this technology to be the best system of continuous emission reduction for wet bottom boilers and is not using the technology to establish a NOx emission limit for wet bottom boilers in this rulemaking.")

[224] Proposed Rule at 20146; Non-EGU Sectors TSD at 43.

[225] Non-EGU Screening Assessment at Table 6 (only identifying SCR as a control technology evaluated for BOF, Blast Furnace, and Sintering processes in the Iron and Steel Industry). In fact, Table 6 reveals that the non-EGU Screening Assessment did not include analysis of <u>any controls</u> at any EAF at all (unless the EAF was for some reason classified as "Industrial Process – General" of "Industrial Process – Other Not Classified," neither of which was evaluated for SCR in any case).

[226] *Genuine Parts Co. v. EPA*, 890 F.3d 304, 311-12, 435 U.S. App. D.C. 338 (D.C. Cir. 2018) (quoting *Carus Chem. Co. v. EPA*, 395 F.3d 434, 441, 364 U.S. App. D.C. 339 (D.C. Cir. 2005)).

technology required would actually reduce NOx emissions. This is in notable contrast to prior rulemakings, where EPA at least attempted to consider levels of emission reductions that might be achieved at individual non-EGU facilities in light of the feasibility of control installation if they were subjected to Good Neighbor regulations.[227] EPA's failure to conduct emission unit-specific assessments of technically feasible emission reductions for the non-EGUs EPA subjects to the emission limits under Proposed Rule is particularly arbitrary in light of EPA's treatment of California's EGUs, which EPA proposes to exempt from the Proposed Rule based on a facility or emission unit specific analysis that significant additional potential emission reductions from the relevant EGU would not be technically feasible,[228] an analysis EPA refused to conduct for any other facility nationwide.

Finally, it is not even clear that EPA based its assumption regarding EAF lb/ton limits currently achieved in practice on a review of solely facilities that have EAFs. For most of the other iron and steel furnace types, EPA identifies which facility permit or state RACT limit EPA reviewed and used as a basis for identifying a lb/ton efficiency limit currently achieved for that furnace type, which EPA assumes could be lower by use of SCR.[229] But for EAFs, EPA does not identify any facility permit by name, instead the Proposed Rule vaguely states that EPA found "Example permit limits at around 0.2 lb/ton" [230] The Non EGU Sectors TSD further states that, for EAFs, "EPA considered a range of baseline emission data and permit limits from mini mills, integrated iron and steel facilities, and ferroalloy facilities ranging from 0.20 lb/ton to 0.35 lb/ton."**231** Because integrated iron and steel facilities generally use Blast Furnaces and BOFs and not EAFs, and ferroalloy facilities do not use EAFs[232] this suggests that EPA looked at non-EAF units as a basis for setting the NOx emission limits for EAFs in the Proposed Rule.[233] To the extent that EAFs at a given facility have an emission rate higher than 0.2 lb/ton identified by EPA, then the SCR control technology proposed by EPA, even if technically feasible to install (which it is not), would have to be shown to be capable of reducing emissions by greater than 25% to justify EPA's assumption that the proposed limits are possible to achieve. For instance, at a facility

[227] See non-EGU emissions reduction assessment prepared for the Revised Cross State Air Pollution Rule Update, available at www.regulations.gov/document/EPA-HQ-OAR2020-0272-0014

[228] Proposed Rule at 20,088.

[229] See Proposed Rule at 20,145.

[230] See Proposed Rule at 20,145.

[231] Non-EGU Sectors TSD at 43.

[232] See Proposed Rule at 20181 (defining an "Electric Arc Furnace" as only those furnaces "equipped with electrodes used to produce carbon steels and alloy steels primarily by recycling ferrous scrap.").

[233] To the extent EPA based the 0.2 lb/ton limit off of the Title V Operating Permit issued to Timken Faircrest in North Canton, OH, there is no such enforceable limit in this permit. The permit establishes a monthly NOx emission limit of 10.833 tons/month averaged over a 12-month basis. See http://wwwapp.epa.ohio.gov/dapc/permits_issued/1448372.pdf . Such a limit is not the same as a 0.2 lb/ton limit averaged over a 3-hour or even 30-day period, particularly since the compliance demonstration is based upon a stack test performed in 2006 (as opposed to the Proposed Rule, which would require compliance demonstrations based upon CEMs).

achieving 0.3 lb/ton with low NOx burners, an SCR would have to be capable of reducing NOx by at least another 50% for the 0.15 lb/ton limit to be possible to achieve.

In addition, while it is true that EPA was able to avoid considerations of unit specific feasibility in prior Good Neighbor rulemakings and simply focus on "fleet average" characteristics, that is only accurate because all such prior rulemakings were based on emission trading schemes with statewide budgets, rather than imposing emission limits on a unit specific basis as it now proposes to do for the first time ever under the Proposed Rule. Even EPA's prior rulemakings acknowledged that that "unit-specific short-term emission rates pose significant implementation and rulemaking challenges," and if EPA were "to choose to implement a unit-specific emissions rate regime for implementation, the compliance flexibility afforded by emissions trading would not be available and it would not be possible to rely on fleet average information to the same extent . . . ."[234] . Thus, EPA cannot evade unit specific feasibility analysis by merely pointing to past rulemaking while ignoring this fundamental difference between an emissions trading program and command-and-control emission limits it seeks to impose on the iron and steel industry. This is especially important where proposed limits begin reaching or exceeding limits of technological feasibility. If EPA wishes to impose emissions limits on a unit specific basis under the Good Neighbor provision of the Clean Air Act, at a minimum, EPA must address the technical feasibility of emission limits on an emission unit basis.[235]

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[234] *Id.*

[235] The comments in this section are specifically tailored to EAFs because those are the only emission units used at U. S. Steel's Arkansas facility (BRS and the EV facilities) with a potential to emit more than 100tpy of NOx. However, these same comments also apply to the other furnace types covered by the Proposed Rule since EPA has not conducted any adequate feasibility analysis for any such furnaces, only identifying a coal-fired annealing furnace as the only furnace type at which an SCR has been demonstrated, and not attempting any facility level feasibility analysis for any furnace type or facility subject to the Proposed Rule. And EAFs are not at all like annealing furnaces. Furthermore, other furnace types have their own unique considerations that would make SCR, SNCR or other controls like low NOx burners not technically feasible; for example, NOx emissions from vacuum degassers are caused only by the control device itself (the flare), and involve very low total emissions of NOx (permitted at 2tpy at U. S. Steel Arkansas facilities), and SCR (or SNCR or any other post-combustion controls) has not been demonstrated to be technically possible let alone feasible or cost effective on either a flare or on such low emission levels. Additionally, the tunnel furnace at the U. S. Steel BRS facility operates at a far higher temperature than SCR can feasibly operate at (over 1000 degrees) (and under what an SNCR can accommodate), and iron oxide scale generated from the slabs rolling over the rollers would bombard any catalyst installed, plugging it and reducing its efficiency and life, and furthermore each time that the door opens to accept a new shuttle there is a sudden increase in air input, causing discontinuity to fluegas airflow which can in turn lead to additional ammonia slip, and even if possible to retrofit, any retrofit would not be cost justified for a source that is under 100tpy of potential NOx emissions, and is already equipped with low-NOx burners such that further reductions based on burner replacement cannot be assumed. Furthermore, although some annealing furnaces may be larger stacked units, many annealing furnaces such as those at the U. S. Steel Arkansas facilities are small (under 6 tpy potential to emit) and only intermittently operated batch processes that are not even stacked, and thus are not amenable to control by CEMS, SCR or other post-combustion control. Also, to the extent SCR is not technically feasible to install in the vents from the EAF, they will likewise necessarily not be feasible to install for any of the small supporting units in the meltshop (including ladle/tundish preheaters, and ladle metallurgy furnaces), since those units do not have independent stacks and instead vent to the same canopy collecting emissions from the EAF. To the extent EPA makes any applicability

B. There are Many Reasons to Conclude that SCR is Not Technically Feasible for EAFs, and/or Would Not Result in the Emission Reductions Assumed by EPA.

There are good reasons why no EAF has ever demonstrated SCR controls in practice – there are many technical issues which could either render installation infeasible or would prevent the SCR from generating the emission reductions it may have in other contexts. This section summarizes many such issues and is informed by BRS' discussions with one of the largest worldwide designers and providers of EAF technology, the SMS Group, and a principal designer of EAF technology utilized at the BRS and EV facilities ("BRS/EV facility"). Neither the SMS Group nor the SCR vendors consulted by Black & Veatch are aware of any EAF steelmaking facility in commercial operation that has successfully installed SCR to control NOx. The attached memorandum from Black & Veatch, an engineering firm with actual experience designing and installing SCR systems at EGUs, also includes more detailed and technical critiques of the technical and economic feasibility of installing SCR at the BRS/EV facility and we hereby incorporate that memorandum by reference.

EAFs are a fundamentally different process than the EGUs at which SCR has been demonstrated. For one, unlike the relative continuous process associated with EGUs, an EAF is a batch process, with emission spikes when the furnace is charged with scrap and the electrodes bore-in initiating the arc (e,g, tapping), as well as emission profile and temperature shifting throughout the melt cycle. This matters because an SCR requires stable gas flow rates, NOx concentrations, and temperature to effectively reduce NOx. The temperatures of the EAFs at the BRS/EV facility exhausts will vary widely over the melt cycle, and the gas flow rates, and NOx concentrations will exhibit a wide amplitude, both of which may limit the efficiency of or damage the catalyst in an SCR. Furthermore, an EAF is not a combustion process, but instead primarily relies on electricity to melt metal scrap,[236] meaning that the emission profile of the process is different than the emission profile associated with combustion of fossil fuels, notably including sulfur dioxide and many metals and materials that are incompatible with the SCR, because certain elements present in EAF emissions, such as iron, arsenic, sodium, potassium, nickel, chrome, lead and zinc and potentially others, can react with platinum catalysts to form compounds or alloys which are not catalytically active. These reactions are termed "catalytic poisoning."[237] Furthermore, any solid material in the gas stream can form deposits and result in fouling or masking of the catalytic surface. Fouling occurs when solids obstruct the cell openings within the

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changes in the final rule, we reserve the right to challenge application of any such limits or controls to non-EAFs as well since EPA has not shown them to be technically feasible.

[236] While some low NOx natural gas burners are used to support the EAF, the majority of emissions from the process are not attributable to these burners (but rather are attributable to thermal NOx). Accordingly, although low-NOx burners can have a marginal impact on emissions, they can only control a small percent of the EAF's total NOx emissions.

[237] EPA has previously acknowledged this to be an issue. See EPA Comments to Cost Estimate Manual, SCR Chapter, pg. 15 "We agree with the commenter that SCR systems applied to units with high dust loading and high concentrations of sulfur and other compounds may deactivate SCR catalysts and hence increase the capital and operating costs of an SCR."

catalyst. Masking occurs when a film forms on the surface of catalyst over time. The film prevents contact between the catalytic surface and the flue gas. It is infeasible to install an SCR upstream of the baghouse which collects these metals and particulate matter, because the SCR catalyst would be bombarded with all these elements which it is not equipped to handle, reducing its efficiency and at best requiring frequent changing of the catalyst. Furthermore, there may be potential for entrained moisture and or condensable emissions that could be detrimental to the catalyst if a leak were to occur from the tubular section or when temperatures and moisture conditions are unfavorable during cycling of systems. The ability of poisoning and fouling to make SCR technically infeasible is not theoretical. As noted in the attached Black & Veatch report, plugging due to sodium in fluegas has prevented efficient operation of SCR during pilot studies at the Coyote Station in North Dakota, and BRS has high levels of sodium in its fluegas (particulate matter from the EAF captured by the baghouse has 8,080 ppm sodium).[238] And courts have upheld BACT determinations, even in the powerplant context, that SCR is technically infeasible where there are fluegas elements including high levels of sodium and potassium likely to jeopardize SCR operability.[239] This is particularly true of EAFs, which typically have high pre-baghouse particulate matter in the fluegas, as compared to coal fired power plants.

Furthermore, the SCR requires operating temperatures between 480°F (250°C) and 800°F (427°C) of the gas stream at the catalyst bed, in order to carry out the catalytic reduction process. But these temperatures are incompatible with the BRS/EV facility's baghouses which requires the inlet to be dropped down to below 266°F (130°C) or the baghouse could catch on fire. This represents the maximum peak temperature at the spark arrestor prior to the baghouse, with temperatures at other times being far lower accordingly. Furthermore, cooler gas makes the baghouse more effective, since the cooler the gas, the more the metals convert from gas to solid phase preventing them from bypassing the baghouse. In order to regulate the inlet temperature to the baghouse, BRS and EV facilities have cooling systems for the ductwork between each EAF and the associated baghouse. The EAF exhaust temperature must be reduced through a significant length of special tubular water cooled duct i to reduce temperatures sufficiently to avoid damage to downstream components and especially the baghouse. These cooling systems are thus also incompatible with installing an SCR prior to the baghouse since cooling systems must remain to prevent temperatures from compromising the baghouse or interfering with reductions in particular matter, but the resulting cooling results in a temperature outside of SCR operating range.[240]

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[238] See e.g., Energy & Environmental Research Center, EVALUATION OF POTENTIAL SCR CATALYST BLINDING DURING COAL COMBUSTION AND ADD-ON: IMPACT OF SCR CATALYST ON MERCURY OXIDATION IN LIGNITE-FIRED COMBUSTION SYSTEMS, 04-EERC-11-09 (Nov. 2004), available at https://www.wrapair.org/forums/iwg/documents/4FactorComments/2009-05x_SCR_Catalyst_Blinding_final_report.pdf

[239] *See e.g. United States v. Minnkota Power Coop., Inc.*, 831 F. Supp. 2d 1109 (D.N.D. 2011).

[240] Notably this temperature issue also definitively rules out SNCR as technically. infeasible as well, since SNCR requires a far higher operating temperature than even SCR, and an even lower control efficiency. See EPA technical bulletin-Nitrogen Oxides (NOx), Why and How They Are Controlled, at 18, EPA 456/F-99-006R (November 1999) (noting SNCR must be operated at 900°C and 1100°C window).

The only point at which the temperature is not below the operating range of an SCR is the very opening of the EAF duct prior to cooling the fluegas, but that is above the temperature for an SCR (around 1,200 to 1,300°F), and any attempt to cool the temperature at the entrance to the EAF duct, such as through the use of tempering fans, would increase the flowrate through the duct and into the baghouse, which also raises a host of feasibility issues. Specifically, use of tempering fans, and/or any pressure changes caused by the SCR and associated equipment risks jeopardizing the facility's existing pollution control equipment, because the EAFs and pollution control system (baghouse) are designed around specific parameters such as flowrate and pressure drop, and any increase in those parameters could at minimum decrease the life of the bags in the baghouse, and at maximum could result in failure of system components.[241] In addition, the tempering fans, SCR and other new equipment would increase electrical demand at the BRS/EV facility, decreasing efficiency and significantly increasing indirect emissions e.g., NOx, SO2, PM, greenhouse gases, etc. associated with the substantial increase in electricity consumption to operate the SCR and associated equipment and additional flue gas cooling systems, and that assumes that sufficient electric capacity and related equipment to transfer such energy loads is available or otherwise is not in excess of current design capacities.

Critically, as noted in the attached Black & Veatch report, available space is very limited between the EAF and the baghouse and likely would prevent an SCR and associated retrofit equipment being installed anywhere upstream of the baghouse, much less by the entrance to the EAF duct. EPA has previously acknowledged that these spatial constraints can pose obstacles to making an SCR installation work.[242]

Likewise, there are also spacing, and structural design and support limitations that may limit the feasibility of installing an SCR into the stack post-baghouse. Specifically, concrete infrastructure post-baghouse including stack foundation and blower house are substantial installations and the existing as-built design restricts access to the exhaust flow. As noted in the attached Black and Veatch report, there is insufficient space between the ID fan and the stack for the SCR, let alone the booster fan that would likely be necessary to maintain pressure, so any installation would require new structural supports, stack breaching, and the new ductwork would

[241] Attempting to cool fluegas by injecting water into the flue gas rather than using a tempering fan would be inefficient because this cooling method is already done (BRS) and will be done, once operational (EV) to lower temperatures to protect the baghouse, but the target temperature for cooling the flue gas for the SCR is different than for protecting and ensuring optimum pollution control efficacy of each baghouse and, as a result, the existing system cannot be used for both purposes, and it is not clear whether it would be possible to design the system to accomplish these two different temperature goals solely through water cooling in the space available.

[242] See EPA Air Pollution Control Cost Manual, edition 6, EPA/452/B-02-001 (Jan. 2002) at section 2.5.4.2 ("an SCR reactor can occupy tens of thousands of square feet and must be installed directly behind a boiler's combustion chamber to offer the best environment for NOx removal. Many of the utility boilers currently considering an SCR reactor to meet the new federal NOx limits are over thirty years old- designed and constructed before SCR was a proven technology in the United States. For these boilers, there is generally little room for the reactor to fit in the existing space and additional ductwork, fans, and flue gas heaters may be needed to make the system work properly.").

require multiple turns that would increase the pressure drop the booster fan would have to provide, and increase power demands, further exacerbating power capacity issues.

Assuming for the sake of argument that an SCR could be designed to be installed after particulate removal by the baghouse to avoid some of these prohibitive conditions, a different type of technical feasibility problem is entailed, because even if an SCR could be installed, the SCR would risk significantly *increasing* emissions, such that the emissions reductions anticipated would not be possible, or may be much smaller than estimated by EPA. This is because the fluegas exiting the baghouse is typically below 200°F, far below SCR operating range. That means that the fluegas would have to be heated post-baghouse by a significant temperature (at least 300°F in a short period of time), requiring significant additional energy, likely from natural gas combustion and associated electricity needs, which in turn would increase the very NOx emissions the SCR is designed to control, as well as increasing greenhouses gas, VOC, CO, SO2 and PM emissions. These increases may be significant as described in the following section, especially compared to the relatively low NOx reductions an SCR would accomplish even if able to run efficiently.

In addition to any increased emissions caused directly by new combustion sources and indirectly due to increased power consumption, unreacted ammonia would also be emitted to the environment as ammonia slip, as described in the following section. Furthermore, formation of ammonium salts can readily foul the catalyst section, resulting in reduced efficiency and increased back pressure, and ammonium salts would be emitted as PM10/PM2.5. And installation after the baghouse system means that these ammonia and ammonium salt emissions would be completely uncontrolled, creating potential compliance and attainment concerns with the PM2.5 emissions limits and NAAQS, respectively. On the other hand, installation of SCR prior to the baghouse system would contaminate the fly ash in the baghouse with ammonia, and as EPA has recognized, "the ability to sell the fly ash as a secondary product is affected by its ammonia concentration."[243] If this compromises BRS' ability to recycle its baghouse dust by resale to reclamation, recycling, or reuse facilities as is BRS' current practice, then the installation of SCR would create a new unrecycled hazardous waste stream. Furthermore, as EPA has also recognized, "ammonia-sulfur salts can plug, foul, and corrode downstream equipment such as air heater, ducts, and fans" thus endangering the existing pollution control system.[244]

Additionally, even if SCR technology could be installed post baghouse, the SCR would have issues with catalyst poisoning due to sulfur, as SO2, reacting with the SCR regardless of the placement of the SCR (impeding technical feasibility) unless desulphurization technology can also be installed (which would entail both its own set of technical feasibility issues in addition to significant additional costs not considered by EPA).

Furthermore, as discussed in the attached Black & Veatch report, stack testing at the U. S. Steel BRS facility shows a NOx concentration in fluegas near the lower limit of what concentration can be controlled by an SCR. According to EPA's own analyses, "Low NOx inlet levels result in

[243] EPA Air Pollution Control Cost Manual, edition 6, EPA/452/B-02-001 (Jan. 2002) at section 2.2.6, page 2-28.

[244] EPA Air Pollution Control Cost Manual, edition 6, EPA/452/B-02-001 (Jan. 2002) at section 1.2.3, page 1-12.

decreased NOx removal efficiencies"[245] an SCR is generally only expected to control 70% of emissions at a part per million ("ppm") loading as low as 20 ppm (putting aside temperature, fouling, poisoning, plugging, and other such issues which could decrease efficiency and/or degrade the catalyst). [246] And we are unaware of any vendor that will guarantee removal efficiency at all much below 5 ppm NOx. These limitations on control efficiency are further exacerbated by the temperature issue, since temperatures on the low end of SCR operability also significantly decrease SCR efficiency as compared to higher temperatures.[247]. Given the combination of very low NOx concentration loadings, and low temperatures, the control efficiencies presumed by EPA in the Proposed Rule are simply not technically feasible.

C. Emission Increases Associated With Installation of SCR.

Based on the engineering review conducted by Black & Veatch and discussed above, the exhaust gas temperature from an EAF, prior to the dedusting baghouse / after the baghouse, is the vicinity of 200 degrees Fahrenheit (F), thus requiring additional equipment to be installed to raise the exhaust gas temperature by at least 300 degrees F to reach the minimum operability range of 500 degrees F for an SCR, as would be required for just 50% NOx removal efficiency (not taking into account the NOx concentration, airflow variability, and poisoning/fouling/plugging issues discussed above). To support reheating of the exhaust gas by an additional 300 degrees F will require the installation of a heating devices, which will consist of the installation / operation of a natural gas fired burner(s).

The amount of energy required to heat the EAF dedusting exhaust air by 300 degrees F can be calculated with the following equation:

- British Thermal Units (BTU) Output = Temperature rise multiplied by (X) cubic feet per minute X BTU per pound per degree F X the density of air at 200 degrees F X 60 minutes per hour.
  - Temperature rise required is 300 degrees F.
  - Exhaust gas flow from an EAF is on average approximately 1,300,000 standard cubic feet per minute (SCFM) from a dedusting system. Actual flow rate (ACFM) does vary based on temperature and other parameters.
  - Specific heat of air at 200 degrees F is 0.24 BTU per pound per degree F.
  - The weight per cubic foot of air is 0.061 (pounds / cubic foot)(lbs/ft3)).
- BTU Output = 300 degrees F. X 1,300,000 cubic feet per minute X 0.24 BTU per pound, per degree X 0.061 lbs/ft3 X 60 minutes / hour = 342.5 MMBtu/hour.

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[245] EPA Air Pollution Control Cost Manual, edition 7 (June 2019) at section 2.2.2.

[246] EPA, Clean Air Technology Center Products, Air Pollution Technology Fact Sheet: Selective Catalytic Reduction (2003), available at https://www.epa.gov/catc/clean-air-technology-center-products.

[247] EPA Air Pollution Control Cost Manual, edition 7 (June 2019) at section 2.2.2 figure 2.2.

To generate the 342.5 MMBtu/hour needed to heat the exhaust gas by 300 degrees F, and assuming the heating value of natural gas is 1,000 BTU per cubic foot, you would need 342,500 cubic feet per hour of natural gas. Combusting that additional natural gas will cause a release of NOx emissions (among other pollutants) during the process of combusting that natural gas in the heating burner(s).

The amount of NOx emissions that can occur when combusting 342,500 cubic feet of natural gas can be calculated using the AP-42 emission factors EPA has published for the purpose of calculating emissions of pollutants from combustion of natural gas.[248] An emission factor is a representative value that attempts to relate the quantity of an air pollutant released to the atmosphere with an activity associated with the release of that air pollutant. These factors are usually expressed as the weight of air pollutant divided by a unit weight, volume, distance, or duration of the activity emitting the pollutant (e. g., kilograms of particulate emitted per megagram of coal burned). Such factors facilitate estimation of emissions from various sources of air pollution. In most cases, these factors are simply averages of all available data of acceptable quality and are generally assumed to be representative of long-term averages for all facilities in the source category (i. e., a population average).

Section 1.4 of AP-42 provides emission factors for quantifying the emissions of NOx, as well as other regulated air pollutants based in the combustion of natural gas expressed in either pounds per MMBtu or pounds per standard cubic foot of natural gas combusted. Tables 1.4-1 and 1.4-2 provided emission factors for various regulated air pollutants. Those emission factors are summarized in the table below:

Combustion type	**Regulated Air Pollutant**	**Emissions Factor ($lb/10^6$ standard cubic foot)**
Large Wall-Fired boilers – Controlled With Low NOx Burners, > 100 MMBtu / Hour Heat Input	Oxides of Nitrogen (NO_x)	140
Large Wall-Fired boilers – Controlled With Low NOx Burners, > 100 MMBtu / Hour Heat Input	Carbon Monoxide (CO)	84

[248] See "Compilation of Air Pollutant Emissions Factors – Volume I: Stationary Point and Area Sources", dated January 1995. The Emission Factor And Inventory Group (EFIG), in the U. S. Environmental Protection Agency's (EPA) Office Of Air Quality Planning And Standards (OAQPS), develops and maintains emission estimating tools used in developing emission control strategies, determining applicability of permitting and control programs, ascertaining the effects of sources and appropriate mitigation strategies, and a number of other related applications. The AP-42 series is the principal means by which EFIG can document its emission factors. These factors are cited in numerous other EPA publications, and electronic data bases, but without the process details and supporting reference material provided in AP-42 and are generally relied on by EPA when source specific testing or CEMS are unavailable.

Large Wall-Fired boilers – Controlled With Low NOx Burners, > 100 MMBtu / Hour Heat Input	Carbon Dioxide (CO_2e)	120,000
Large Wall-Fired boilers – Controlled With Low NOx Burners, > 100 MMBtu / Hour Heat Input	Particulate Matter <2.5 Microns ($PM_{2.5}$)	7.6
Large Wall-Fired boilers – Controlled With Low NOx Burners, > 100 MMBtu / Hour Heat Input	Sulfur Dioxide (SO_2)	0.6
Large Wall-Fired boilers – Controlled With Low NOx Burners, > 100 MMBtu / Hour Heat Input	Volatile Organic Compounds (VOCs)	5.5

To estimate the potential emissions of the above listed regulated air pollutant, the emission factor expressed in pound per million cubic standard feet of natural gas is multiplied by the quantity of natural gas combusted in an hour to get pounds of that air pollutant per hour and then the amount of natural gas consumed in a year to get pounds per year or commonly expressed as tons per year. Provided in the table below is an estimate of the additional air pollutants that would be released in the atmosphere based on installation of natural gas burners to heat the EAF exhaust air by 300-degree F, to allow for SCR to operate at even minimum effectiveness.

Regulated Air Pollutant	**Emissions Factor (lb/10^6 standard cubic foot)**	**Estimated million (10^6) standard cubic ft per of hour of Natural Gas)***	**Estimated Lbs Per Hour Emission Rate**	**Estimated Tons Per Year****	**Estimated Tons Per Ozone Season*****
Oxides of Nitrogen (NO_x)	140	0.3425*	47.95	210.0	87.5
Carbon Monoxide (CO)	84	0.3425*	28.77	126.0	52.5
Carbon Dioxide (CO_2e)	120,000	0.3425*	41,100	180,018	75,007.5
Particulate Matter <2.5 Microns ($PM_{2.5}$)	7.6	0.3425*	2.6	11.4	4.75
Sulfur Dioxide (SO_2)	0.6	0.3425*	0.21	0.92	0.38

Volatile Organic Compounds (VOCs)	5.5	0.3425*	1.88	8.23	3.4

* As noted above the amount of natural gas estimated on an hourly basis to heat exhaust gas up by 300 degrees F is 342,500 standard cubic feet per hour. Expressed in lbs/106 standard cubic foot would be 0.3425 lbs/million standard cubic foot.

** Assumes operation 24 hours a day 365 days per year.

***Tons per year multiplied by 5/12 to reflect five months of ozone season.

It is important to note, that the above estimated emissions of regulated air pollutants are additional amounts of these air pollutants that would be generated / released to the atmosphere based on the required heat the EAF dedusting exhaust gas by 300-degree F to allow for SCR to operate. An additional 250-degree F raise in the temperature would be required so that the SCR could operate at the optimum temperature (i.e., to achieve a 90% reduction in NOx emissions), which is around 750-degree F in NOx emission levels. The amount of energy required to raise that temperature would require the natural gas volume to be increased by almost a factor of two. In that case, the projected emissions rates would also increase by a factor of approximately two. Note also that this is an estimate of the increased air pollutant emissions per EAF and would thus need to be multiplied by each EAF to which SCR is applied which for the case of the BRS/EV facility, would be four (4) times to reflect four (4) EAFs.

Notably, as explained elsewhere in these comments, the Proposed Rule would decrease the permitted lb/ton NOx rate for each of the BRS/EV EAFs by up to 50% by reducing the current permit limit of 0.3 lb/ton to the Proposed Rule limit of 0.15 lb/ton. At a presumed capacity of 250 tons/hr for each EAF, times 3,672 hours per ozone season, that represents a reduction of up to 137,700 lb (i.e., 68.85 ozone season tons) per EAF. Comparing these maximum potential reductions (68.85 ozone season tons) to the potential NOx increases (87.5 ozone season tons), it appears that the changes to an EAF dedusting exhaust gas temperature necessary to enable SCR to function could be even higher than the potential NOx reductions achieved by installation of an SCR units at the BRS/EV facility.

In addition to emission increases associated with installation of natural gas fired burners needed for EAF dedusting exhaust gas heating, the ammonia slip associated with SCR installation would cause the release of ammonia emissions (in the form of particulate matter) from each EAF, which are typically not associated with dedusting exhaust gases. The term slip implies that not all of the ammonia used in the SCR system chemically reacts to reduce the presence of NOx in the dedusting exhaust air. EPA's own estimates suggest that SCR can be associated with 2 to 10 ppm ammonia slip, and even a well-functioning SCR would have ammonia slip of 2 to 5 ppm, with ammonia slip increasing as catalyst activity decreases, as it might be expected to occur given the range of feasibility issues entailed in installation on an EAF, including the high temperature variability and airflow variability, and poisoning/fouling/plugging issues.[249]

Using an estimate of 5 ppm ammonia slip due to the factors outlined above, a general estimate of the quantity of ammonia slip can be estimated as follows:

- Appendix A to AP-42 provides the following equation for converting ppm by volume to pounds per cubic foot: M/385.1 X $10(^{6})$, where M= Molecular weight of gas. Molecular weight of ammonia is 17.03. Thus 1 ppm ammonia = 17.03/385.1 x $10(^{6})$ = 4.42 x. $10(^{-8})$ lb ammonia/ft^3
- Thus, 5ppm ammonia slip = 5 x. 4.42 X $10(^{-8})$ lb/ft^3 = 22.1 X $10(^{-8})$ lb/ft^3
- Exhaust gas flow from an EAF is on average approximately 1,300,000 scfm. Actual flow rate does vary based on temperature and other parameters. Multiplying this per minute flowrate by 60 yields a per hour flowrate of 78,000,000 standard ft^3/hour (hr).
- Thus, 22.1 X $10(^{-8})$ lb/ft^3 X 78,000,000 ft^3/hr = 17.238 lb of ammonia slip per hour.

Assuming operation only during the ozone season, 17.238 lbs/hr X 8760 hrs/year (yr) x. 5/12 ozone months/ year X 0.0005 ton/lb = 31 tons of ammonia per ozone season per EAF. Notably, if the SCR was installed downstream of the baghouse, this would be uncontrolled emissions, and would increase PM2.5, since ammonia is recognized to be a significant precursor to secondary particulate matter emissions.[250] In fact, some studies have suggested that reducing ammonia emissions to reduce condensable particulate matter is more cost effective than NOx reductions.[251] On the other hand, if installed upstream of the baghouse, any portion not emitted would contaminate the baghouse dust that is currently recycled/reclaimed by a third party, potentially creating a new and significant hazardous waste stream.

Taken together, the increased NOx emissions from dedusting exhaust air heating and ammonia (i.e., particulate matter) emissions from ammonia slip would negate any environmental value of the SCR given the equivalent or smaller amount of NOx the SCR would be capable of

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[249] EPA Air Pollution Control Cost Manual, edition 6, EPA/452/B-02-001 (Jan. 2002), at section 2.2.2, page 2-13.

[250] See e.g., Plautz, Ammonia, a poorly understood smog ingredient, could be key to limiting deadly pollution (2018), available at https://www.science.org/content/article/ammonia-poorly-understood-smog-ingredient-could-be-key-limiting-deadly-pollution; Wang, S., Nan, J., Shi, C. *et al.* Atmospheric ammonia and its impacts on regional air quality over the megacity of Shanghai, China. *Sci Rep* **5,** 15842 (2015), available at https://doi.org/10.1038/srep15842 ; Behera, S. N. & Sharma, M. Investigating the potential role of ammonia in ion chemistry of fine particulate matter formation for an urban environment. Sci. Total Environ. 408, 3569–3575 (2010), available at https://www.sciencedirect.com/science/article/abs/pii/S0048969710003955; Yiyun Wu, Baojing Gu, Jan Willem Erisman, Stefan Reis, Yuanyuan Fang, Xuehe Lu, Xiuming Zhang, PM2.5 pollution is substantially affected by ammonia emissions in China, Environmental Pollution, Volume 218, p.86-94 (2016), available at https://doi.org/10.1016/j.envpol.2016.08.027.

[251] Baojing Gu, Lin Zhang, *et al.* "Abating ammonia is more cost-effective than nitrogen oxides for mitigating PM2.5" Science, v.374 no. 6568, p.758-762 (2021), available www.science.org/doi/abs/10.1126/science.abf8623

reducing from each EAF. This demonstrates that SCR installation is not a technically feasible means of decreasing NOx from EAFs by ~50% as would be required to meet the limits in the Proposed Rule and requiring SCR in the face of these realities is arbitrary and capricious.

Finally, it should be noted that unlike SCR retrofits in the powerplant sector where increased air pollution emissions associated with installation of an SCR (both ammonia slip and emissions from heating or cooling fluegas) could be outweighed by even a marginal percentage reduction of NOx given the magnitude of NOx emissions at EGUs (thousands to tens of thousands of tons of NOx per year), in non-EGU contexts like those in the steel industry where EPA proposes to require SCR at units as small at 100 tons per year of NOx, the magnitude of NOx reductions that could be achieved by SCR is simply not significant next to the increased air pollution emissions associated with installation of an SCR. Under these circumstances, SCR is infeasible from an emission reduction perspective because the smaller decreases in NOx associated with SCR at a unit with only a few hundred tons of potential emissions NOx could be significantly offset or even swallowed by electrical consumption of the SCR and its related equipment (indirect emissions) as well as increased emissions from fluegas heating or the increased indirect emissions associated with an increase in energy consumption associated with flue gas cooling equipment, both of which would significant heat/electrical input due to the conditional dynamics required in such short distances.

XVIII. EPA's Cost Analysis Is Arbitrary and Unreasonable as Applied to EAFs, and Especially to Those in Arkansas

A. EPA Fails to Provide Any Cost Estimates Specific to EAFs, Despite Taking Cost Into Account For Other Types of Emission Units

EPA has not provided a cost-analysis specific to EAFs. Instead, EPA provides a generalized estimate $4,345/ton for SCR installation in the broad industry of "Iron and Steel Mills and Ferroalloy Manufacturing." In the first place this generalized aggregation is inappropriate because, as EPA has previously recognized, EAFs are distinct from both ferroalloy production and from other types of steel production such as integrated iron and steel mills.[252] Furthermore, EPA's failure to examine SCR installation on steel mill EAFs is particularly inadequate in light of EPA's

[252] E.g., 57 Fed. Reg. 31,576, 31,582, 31,591 (July 16, 1992) (after determining to "list broad categories of major and area sources rather than very narrowly defined categories," listing Ferroalloy Production, Integrated Iron and Steel Manufacturing, and Electric Arc Furnace Operation as wholly separate source categories under section 112 of the CAA); 39 Fed. Reg. 37,466 (Oct. 21, 1974) (When first proposing CAA Section 111 new source performance standards for EAFs, differentiating EAFs from "old open hearth furnaces"); Background Information for Proposed New Source Performance Standards: Asphalt Concrete Plants, Petroleum Refineries, Storage Vessels, Secondary Lead Smelters and Refineries, Brass or Bronze Ingot Production Plants, Iron and Steel Plants, Sewage Treatment Plants - Volume 1 Main Text at 49, APTD-1352 (June 1973) (As part of docket supporting first NSPS standards for Iron and Steel Plants, eventually published at 39 Fed. Reg. 9308, differentiating between production via "Basic oxygen process; operation of open hearth, blast, and electric furnaces" and stating "The proposed standards would only apply to basic oxygen process furnace"); Background Information for Standards of Performance: Electric Arc Furnaces in the Steel Industry Volume I: Proposed Standards, at 1-4, EPA-450/2-74-017a (1974) (when first setting an NSPS standard for EAFs, differentiating between electric arc furnaces, basic oxygen process, open hearth steel production furnaces, blast furnaces, and coke and sintering plants).

recent declaration that that emission units "must be assessed on an individual basis to determine whether SCR is a feasible control technology based on its site-specific characteristics and the SCR technology available at the time."[253] By failing to conduct any feasibility or cost analyses regarding EAFs, EPA has impermissibly "failed to rely on its own judgment and expertise."[254] If EPA still maintains that units "must be assessed on an individual basis," then it has an obligation to do so. And if EPA no longer stands by that position, it has an obligation to justify its departure from prior policy. EPA has done neither, impermissibly attempting to "depart from prior policy *sub silentio*."[255]

Not only is the cost analysis devoid of any data pertaining to the installation of SCR controls on EAFs, EPA's modeling of cost/ton estimates for SCR did not even include any EAFs at any site in its cost analysis.[256] The Proposed Rule's assertion that EAFs can install SCRs below the cost threshold of $7,500 per ton of NOx is unsupported by the screening assessment on which EPA purports base its assumptions. Furthermore, EPA's own Control Cost Manual in the docket admits that the cost estimates provided <u>are not applicable to non-EGUs</u>, stating that "The procedures to estimate capital costs are not directly applicable to sources other than utility and industrial boilers"[257] and "Due to the limited availability of equipment cost data and installation cost data, the [EPA's Integrated Planning Model EGU specific] equations for SCR capital costs were not reformulated."[258]

Accordingly, as currently composed the Proposed Rule is in clear violation of EPA's obligation to "reflect upon the information contained in the record and grapple with contrary evidence,"[259] and to promulgate internally consistent rules.[260] An agency decision is arbitrary and capricious where, as here "the agency has failed to 'examine the relevant data' or failed to 'articulate a rational explanation for its actions.'"[261]

B. EPA Significantly Underestimates Costs Associated with SCR Installation on an EAF:

Even if one incorrectly assumes that it is feasible to install SCRs on EAFs, there are several reasons why costs will be significantly greater than claimed by EPA, for example:

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[253] EPA Comments to Cost Estimate Manual, SCR Chapter, pg. 9 (emphasis added).

[254] *Am. Lung Ass'n v. EPA*, 450 U.S. App. D.C. 385, 415, 985 F.3d 914, 944 (2021).

[255] *FCC v. Fox TV Stations, Inc.*, 556 U.S. 502, 515-16, 129 S. Ct. 1800, 1811 (2009).

[256] Non-EGU Screening Assessment at Table 6.

[257] Control Cost Manual at 6.

[258] *Id*. At 65.

[259] *Fred Meyer Stores, Inc. v. NLRB*, 865 F.3d 630, 638, 431 U.S. App. D.C. 283 (D.C. Cir. 2017).

[260] *Hsiao v. Stewar*t, 527 F. Supp. 3d 1237, 1252 (D. Haw. 2021), quoting *Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134, 1141 (9th Cir. 2015) ("[A]n internally inconsistent analysis is arbitrary and capricious.").

[261] *Genuine Parts Co. v. EPA*, 890 F.3d 304, 311-12, 435 U.S. App. D.C. 338 (D.C. Cir. 2018) (quoting *Carus Chem. Co. v. EPA*, 395 F.3d 434, 441, 364 U.S. App. D.C. 339 (D.C. Cir. 2005)).

1. If it were possible to install SCR on EAFs, as noted above, it would require the addition of various systems and equipment to heat and/or cool the exhaust steam, and to reduce pre-baghouse particulate matter loading, and require significant re-engineering of entire air pollution control systems to ensure compatibility and functionality. The cost for this new equipment is not currently accounted for in EPA's cost estimates for SCR installation at EAFs, and as noted in the attached memo from Black and Veatch, these costs are significant.
    a. As noted in Black & Veatch's report, even if one incorrectly assumes that it is technically feasible to install an SCR between the EAF and the baghouse (e.g., catalyst poisoning/plugging/fouling, available space, temperature issues, etc.), the costs installed costs associated with that equipment, whether it is a tempering air system or a spray duct water system are significant, with installed costs (minimally without the benefit of more detailed engineering) of at least \$11.7 million and \$11.2 million, respectively, for each EAF at the BRS/EV facility (not accounting for ongoing operation and maintenance costs, including increased electricity consumption).
    b. A duct burning system to heat the flue gas after the baghouse likely would cost upwards of \$27,800,000 just to install the burners necessary to sufficiently heat the fluegas for SCR to be operable, without even accounting for ongoing operation and maintenance costs, including increased utilization of natural gas).
2. Increased emissions as a result of such heating fluegas in turn would increase SCR costs because the size of the SCR system would need to be increased to reduce these newly introduced emissions. Note also that further NOx controls would be required by third parties to offset indirect NOx emissions associated with indirect emissions associated with electricity demand associated with the operation of the SCR as well as any flue gas cooling system.
3. In order to reduce the large temperature fluctuations throughout the EAF process that might otherwise be destructive to the catalyst, equipment would have to be installed to balance the temperature. Such equipment is not accounted for in EPA's cost estimates for SCR installation at EAFs.
4. In order to reduce inconsistencies in gas flow given the batch nature of the process, additional equipment would have to be installed to level out the velocity of the flue gas and increase it during certain process periods in order for it to flow through the SCR at a reasonable and consistent rate. This new equipment is not accounted for in EPA's cost estimates for SCR installation at EAFs.
5. CEMS are very expensive and EPA specifically says it did not include them in the cost efficiency estimates. More specifically, based on customer-friendly industry quotes obtained by Black & Veatch, installation of a single CEMS system at a single EAF would cost at least \$300,000 in capital expenditure. Installation and certification would be at least

an additional $100,000. Annual O&M costs just from a Preventative Maintenance contract would cost at an additional $100,000 per year. These costs do not reflect contingencies that often arise during retrofit CEMs projects. The Proposed Rule would require at least four CEMS units (one for each EAF) at the U.S. Steel BRS and EV facilities in Arkansas.

6. EPA's cost estimates have not been inflation adjusted to 2022 dollars. In addition to inflation, the new normal in the wake of a national pandemic and its havoc on industry has resulted in persistent supply chain issues, which further drives costs. And supply chain issues and associated costs will only be exacerbated by any rule requiring everyone in the industry to purchase and install the same equipment. In light of these factors, it is inappropriate to use older cost estimates without any attempt to adjust anticipated costs to reflect the new normal.

7. Actual studies have been performed to account for the full costs associated with SCR retrofits in the EGU sector suggesting that design, equipment, and installation cost upward of $50 Million in 2006 dollars,[262] or approximately $66 Million in 2021 dollars.[263] Although these cost estimates were for EGUs, they are the only cost estimates available for real world retrofit costs since the technology has never been demonstrated on an EAF. In fact, if possible at all, as noted above, modifications not typically needed at a power plant, such as significant flue gas heating or cooling would be required, so it is reasonable to expect that costs could be higher than these estimates associated with SCR retrofit at an EGU (though EPA has never to our knowledge attempted to estimate costs associated with retrofitting an EAF with SCR, perhaps because it has never been deemed technically feasible as would be consistent with EPA's express statements and determinations prior to the Proposed Rule). At the BRS and EV facilities, the control efficiency required for EAFs in the Proposed Rule would only yield a maximum (potential) NOx reduction of 68.85 ozone season tons from each EAF. The actual NOx reductions achieved would, in reality, be significantly less than this figure since this figure assumes 24/7/365 production at the highest permitted emission rate and throughput from the EAFs which is not a realistic assumption given actual observed NOx emissions and periodic and planned outages for routine maintenance.

8. A study of actual operation and maintenance cost by Electric Power Research Institute found that O&M for an SCR can cost upwards of $2 Million/year.[264] Accordingly, under the extremely conservative assumption of 68.85 ozone season tons per EAF/SCR, this O&M estimate, taken alone, would translates to a cost of $29,049 per ozone season ton

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[262] POWER, "Estimating SCR Installation Costs" (Feb. 15, 2006) (discussing EUCG inc. survey of 72 power plants, showing avg cost of 170/Kw for plants in the 300MW range.

[263] Based on CPI Inflation Calculator, available at https://www.bls.gov/data/inflation_calculator.htm (comparing January 2006 dollars to January 2021 dollars).

[264] Electric Power Research Institute, "Operation and Maintenance Costs for Selective Catalytic Reduction Systems" (Technical Update, December 2017).

reduced[265], almost four times EPA's cost effective threshold of $7,500 in the Proposed Rule; and this figure only accounts operation and maintenance, not including the additional significant annualized portion of the initial SCR installation cost.

9. Because of the very different types of ducts required for each EAF, limitations on space available, the designs of these duct systems, the exhaust conditions, temperature delta between them, it is not unreasonable to presume that multiple systems (more than just one tempering or duct burner and SCR unit per EAF unit) may be required in order to achieve predictable repeatable conditions required for the SCR to perform its function without risk of damage to it or other systems.
10. Any retrofit that involves the pollution control system will require operational shutdown for during certain time periods due to system designs and interdependencies, and since the facility cannot legally operate without venting to the pollution controls, and the resulting outage cost from a retrofit could be catastrophic to the iron and steel industry. Notably, steel production is unlike an electric utility with an obligation to provide power 24/7/365 under the worst conditions and therefore has planned accordingly by having a large fleet of electricity units (or contracts with such units) that can be ramped up to replace power during outages. This extended downtown also could result in significant financial implications as electricity and natural gas supply contracts require payment regardless of use. During the months that will likely be needed to ensure equipment and pollution control devices are operational and that all technological retrofits and changes needed have been made, there will simply be no steel production. The Proposed Rule clearly does not consider or contemplate these issues.

C. Cost Annualization Should Account for Fact that Reductions are Not Needed After 2028 in Arkansas.

If EPA does not adjust compliance obligations for Arkansas non-EGU's based on White Bluff's imminent closure, as discussed above, then in the alternative, EPA must at minimum correct the cost analysis to account for the fact that any emission reductions from non-EGUs in Arkansas are only needed for a maximum of two years (2026 and 2027), due to the closure of Entergy's White Bluff coal plant in 2028, since any reductions from non-EGUs beyond that point are unnecessary in order to ensure downwind attainment based on EPA's modeling.[266] Accordingly, the cost of SCR installation at Arkansas non-EGUs should only be annualized over that two year period which is the only period it is legally relevant, rather than annualized over the life of the equipment. Based on the costs estimates derived from EGUs discussed above, this would result in an theoretical, estimated cost per ton calculation for SCR installation at U. S. Steel's BRS and EV facilities of $479,303/ton of NOx reduced per EAF, not even accounting for O&M costs

[265] $2,000,000 / 68.85 tons = $29,049.

[266] See above discussion regarding amount of White Bluff emissions versus the amount of reductions EPA modeled from non-EGUs as a result of the Proposed Rule.

or the other technical impediments discussed in this Section .[267] Given the massive cost per ton associated with such a scenario, EPA should instead consider more cost effective short term methods in Arkansas for the 2026 and 2027 ozone seasons and should coordinate with the State of Arkansas in the selection and implementation of such methods.

SPECIFIC COMMENTS PERTAINING TO BY-PRODUCTS COKE MAKING FACILITIES

XIX. EPA Miscategorizes and Fundamentally Misunderstands By-Products Coke Making; and Misapplies Emissions and Technologies to the Process

EPA failed to perform any coke making stakeholder engagement whatsoever in advance of the Proposed Rule. This lack of stakeholder engagement has contributed to EPA's failure to understand the by-product coke making process. The docket associated with the Proposed Rule is extremely light on any technical support for the proposed NOx limits to charging and pushing, and it is apparent that what little information is provided in the docket is not representative of the by-products coke making process. In its rush to regulate, EPA is relying on scant information from heat recovery coke making which is fundamentally different and not representative or applicable to by-products coke making. Furthermore, and most significantly, there are several inconsistencies throughout the Proposed Rule.

U. S. Steel has one remaining coke plant in its footprint – consisting of ten by-products batteries - that is critical to our integrated operations and the domestic iron and steel making industry as a whole. The Clairton coke plant ("Clairton Plant") provides coke to U. S. Steel facilities with blast furnaces as well as third parties – all that are located off-site, and are separate from the Clairton Plant (i.e., the Clairton Plant is not co-located with any blast furnaces.) The facility is the largest coke making facility in North America and is subject to the most stringent air pollution control regulations in the county, according to the Allegheny County Health Department ("ACHD") who has been delegated authority to regulate air pollution sources in Allegheny County from EPA and the Pennsylvania Department of Environmental Protection. After several BART and RACT evaluations over decades, never has EPA, PADEP or ACHD determined that SCR was a suitable or appropriate technology for charging or pushing activities associated with the coke making process. Never before has any of the agencies asserted that charging coal into coke ovens was a significant source of NOx. To the contrary, in AP-42, EPA acknowledges that NOx emissions from charging are not significant.[268] Furthermore, in applying BACT to C Battery in 2012, ACHD determined that SCR was not appropriate.

In the Proposed Rule, EPA upends and departs from years of prior precedent and knowledge with a couple of ambiguous, and even illogical, paragraphs.[269] Yet, this proposed

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[267] ($66 Million / 2 years) / 68.85 ozone season tons per year = $479,303/ton.

[268] https://www.epa.gov/sites/default/files/2020-11/documents/c12s02_may08.pdf

[269] See page 44 of the Non-EGUs Sectors TSD, where EPA attempts to justify the proposed limits for coke plants with nothing more than: "For coke ovens (charging) and coke ovens (pushing), EPA based the emission limit of 0.15 lb/ton for charging and 0.015 lb/ton for pushing on projected reduction efficiency of 40-50% based on current

technology has not been shown to be available or feasible for these emission sources. While we have many concerns over the Proposed Rule as it would apply to coke batteries, the first overarching comment, as a general matter, is that the Clairton Plant is NOT integrated physically with any iron and steel facilities (e.g., blast furnaces, basic oxygen furnaces, etc.) The facility is a physically separated form and is not part of any "stationary source" consisting of U.S. Steel's integrated iron and steel facilities and operates under the NAICS code 3241, "Petroleum and Coal Products Manufacturing." Thus, grouping coke in the iron and steel sector is inappropriate – especially when Congress and EPA have historically considered the processes unique and separate in other rulemaking efforts. If the coke industry were properly classified in the NAICS code 3241, the charging and pushing would not be included - which is much more logical than what EPA attempts to do in the Proposed Rule.[270]

Second, the Proposed Rule, as it applies to charging at coke plants, is inconsistent and illogical. As noted above, the NAICS code of 3311 is not applicable to stand-alone coke plants. In addition to this inconsistency (where EPA categorizes coke into NAICS code of 3311), in Table I.B-4 of the Proposed Rule, EPA proposes a NOx charging limit of 0.6 lbs/ton of coal charged for coke ovens (charging *and coking*). However, the reference to including "coking" and the 0.6 lbs/ton of coal charged limit is not explained or supported in the Non-EGU Technical Support Document (TSD). Furthermore, it is unclear as to what aspect of the "coking" process EPA intends to regulate, where it intends to regulate, and how it intends to regulate "coking" as noted in this Table – as the docket is void of any supporting information. To add further inconsistencies, in the TSD, EPA attempts to explain the process, but by doing so, it creates additional ambiguities:

> "Often situated in front of a bank of coke ovens, *a separate machine is responsible for opening the coke oven doors, charging and pushing the raw material, and closing the oven again. This machine is often termed a larry car, or charging and pushing machine, among other terms."* [271]

This statement does not accurately describe charging and pushing in a by-products coke oven. While a larry car is used in by-products ovens, it is separate and distinct from pushing and is *done at the top of the oven*. Thus, in a by-products battery, a weighed amount or specific volume of coal is discharged from the bunker into a larry car - a charging vehicle that moves *along the top of the battery*. The larry car is positioned over the empty, hot oven (called "spotting"), the lids on the charging ports are removed, and the coal is discharged from the hoppers of the larry car into the oven. To minimize the escape of gases from the oven during charging, steam aspiration is used

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permit emission limits and production-based push/charge cycles. EPA projects minimally 40% NOx reduction efficiency is achievable by use of low-NOx practices, staged pushing and hood configurations, and potential use of add-on NOx control technology at larry cars and pushing/charging machines, including potential use of low-NOx burners, flue gas recirculation, and/or the addition of selective catalytic reduction to mobile hoods and particulate matter control devices."

[270] See, e.g., NESHAP MACT for coke making (Subpart CCCCC) which is separate from NESHAP MACT for integrated iron and steel (Subpart FFFFF)

[271] Page 24 of Non-EGU TSD.

at most plants to draw gases from the space above the charged coal into a collecting main. In addition, charging is not known to emit any appreciable amounts of NOx. It is also not clear on how one would install and operate an SCR on a moveable larry car as EPA seems to propose.

The inconsistencies and ambiguities do not end there. In the TSD, EPA attempts to explain:

> "For coke ovens (charging) and coke ovens (pushing), EPA based the emission limit of 0.15 lb/ton for charging and 0.015 lb/ton for pushing on projected reduction efficiency of 40-50% based on current permit emission limits and production-based push/charge cycles. EPA projects minimally 40% NOx reduction efficiency is achievable by use of low-NOx practices, staged pushing and hood configurations, and potential use of add-on NOx control technology at larry cars and pushing/charging machines, including potential use of low-NOx burners, flue gas recirculation, and/or the addition of selective catalytic reduction to mobile hoods and particulate matter control devices."

Yet, the on-line version of AP-42 refers to a NOx emission factor for charging of 0.03 lb/ton of coal charged, not the 0.3 lb/ton referenced in the preamble of the Proposed Rule, where EPA explains that the proposed NOx limit of 0.15 lb/tons of coal charged is based upon an assumption of "50% reduction staged combustion and/or limited use SCR/SNCR during charging operations from AP-42 0.3 lb/ton emission factor." It is unclear if EPA's reference to 0.3 is in error; or if the AP-42 emission factor is in error. In any case, clarification is needed.

It is significant to note, too, that according to the non-EGU TSD, EPA's proposal assumes a projected reduction efficiency of 40-50% based on current permit emission limits and production-based push/charge cycles; and that EPA projects minimally 40% NOx reduction efficiency is achievable by use of low-NOx practices, staged pushing and hood configurations, and potential use of add-on NOx control technology at larry cars and pushing/charging machines, including potential use of low-NOx burners, flue gas recirculation, and/or the addition of selective catalytic reduction to mobile hoods and particulate matter control devices. While EPA makes these very broad assumptions and conclusions on the expected reductions on one hand, on the other hand, in the non-EGU TSD, EPA acknowledges that, "coke ovens with NOx controls in the United States have not been found." Yet, EPA, for the first time, is proposing sweeping NOx controls across coke plants in the United States under the guise of its authority under the Clean Air Act to address interstate transport of pollutants.

It is important to add, that overall, the NOx emissions from charging and pushing are minimal and any emissions control equipment installed would result in minimal NOx reductions. Most importantly the application of SCR technology is not feasible from a technical perspective and, even if assuming it was, is not economically feasible, particularly in light of EPA's limited legal authority in the Proposed Rule to impose only controls necessary to mitigate significant contribution to nonattainment or interference with maintenance without any overcontrol. It also would substantially increase other pollutants. Work produced by Trinity Consultants shows:

> "Trinity calculated cost effectiveness for potential application of SCR at the Clairton C Battery coke pushing, after the baghouse. The minimum annual cost effectiveness would

be \$271,472/ton (2021\$), with 72 tons of NO_X formed from combustion of natural gas to reheat the exhaust gas steam compared to approximately 92 tons from the unit itself, as well as approximately 87,000 tpy of CO_2."

These numbers clearly show how the application of SCR to coke ovens is not a cost-effective approach and should not be required. This is yet another example of the Proposed Rule not accurately reflecting the costs of implementation and overstating the potential NOx reductions.

In addition, it is unclear as to what coke plants would even be subject to the rule because the two types of emission units at coke plants that would be subject to the rule are (1) coke ovens (charging) and (2) coke oven push cars and pushing-charging machines (pushing). Based upon the description of the "emission unit" in the proposed rule and the applicability, it would appear that no coke oven (or coke battery, for that matter) would be subject to the proposed limits because the PTE at these two sources are well below 100 tons.

U. S. Steel also respectfully notes that it is unclear on how EPA's modeling incorporates NOx reductions that would be achieved through these NOx emission limits. For example:

- In the pre-FIP model, what inputs did EPA consider from coke plants?
- How were these relatively insignificant sources of NOx emissions shown to contribute or interfere with ozone nonattainment in downwind receptors?
- How did EPA show that the proposed controls for these units would result in any measurable improvement in ozone concentrations monitored at n downwind nonattainment receptors?

For the reasons explained above, U. S. Steel respectfully contends the Proposed Rule is fatally flawed because the emission estimates and projected reductions are not legally or technically supported by anything in the docket – and we further contend that this is because the Proposed Rule as it applies to coke plants is indeed unsupportable by fact or law.

SPECIFIC COMMENTS PERTAINING TO INTEGRATED STEEL MAKING OPERATIONS

XX. Summary of Overarching Concerns

As explained in more detail throughout and below, we have the following overarching concerns with the Proposed Rule as it relates to U.S. Steel's integrated steelmaking operations:

1. Due to numerous fatal flaws and fundamental errors in the proposed rule, EPA must re-evaluate ozone impacts from the iron and steel industry to determine if they do indeed interfere with ozone attainment in downwind states; and only if it is shown that such interference does occur and only after State are afforded ample opportunity to correct any SIP deficiencies, issue a revised proposal with requisite supporting information for the Good Neighbor FIP for the steel industry.

2. The comment period was entirely insufficient and unjustified as EPA supporting documentation is very scant for many emissions units and their respective proposed limits.

3. The docket is missing numerous critical files to evaluate EPA's proposal. Providing the critical files for stakeholder review and comment is needed for stakeholders to provide comments.

4. There was insufficient time to conduct a robust review of the air quality modeling and to conduct an independent modeling analysis, especially in light of the fact that it took several days after the public comment period for EPA to provide stakeholders with the requested modeling files – inappropriately abbreviating an already entirely too short comment period. The files should have been public available on Day One of the comment period.

5. EPA inappropriately uses a 1% (0.7 ppb) threshold rather than the 1 ppb threshold that EPA previously provided States as an appropriate threshold to determine potential NAAQS interference. In short, EPA provided guidance to States (and the regulated community and other stakeholders) and then rejected SIPs that relied on that guidance, and, instead, replaced it with a lower triggering threshold to supplant state's engagement and primacy in the implementation of the Clean Air Act requirements as Congressed intended.

6. The docket does not have the requisite information to support a finding that the facilities in the EPA's iron and steel sector significantly interfere with ozone attainment in downwind states.

7. EPA's stated basis for cost-effectiveness is RACT, but EPA applied beyond-RACT and beyond-BACT/LAER levels of control to establish emission limits for the steel industry, without any justification of its deviation from RACT. It is illogical on how EPA is now attempting to impose limits that are akin to RACT limits that are more stringent than BACT and LAER limits. A review of the RBLC does not support EPA's proposed limits and technologies.

8. EPA's reliance upon the Menu of Control Measures (MCM) and the Control Strategies Tool (CoST) to identify cost-effective emissions control options for the steel industry is fundamentally flawed, as the underlying studies that EPA used to identify cost-effectiveness did not include numerous U. S. Steel source types where EPA proposes controls in the rule, and EPA chose cost-effectiveness values at the bottom of the study cost ranges despite statements in the underlying studies regarding the screening level approach and likely under-estimating costs.

9. Underlying studies only estimated NOX control costs for reheat and annealing furnaces

10. EPA improperly assigned cost data based on reheat and annealing furnaces to all steel process units in the proposed rule

11. There is no basis in EPA's inclusion of numerous other steel unit types for regulation based on CoST and MCM, when CoST and MCM only have input data for annealing and reheat furnaces

12. EPA's cost estimates inaccurately assume year-round operation of control devices resulting in underestimating cost-effectiveness because the regulation can only apply to the five month ozone season, meaning EPA's cost estimates were only 5/12 or 42% of the real cost effectiveness – This critical error significantly underestimates the cost effectiveness of the proposed controls (even if such controls were found to be technologically feasible)

13. Nothing in the docket supports a finding that any of the proposed reductions (individually or collectively) would have any measurable impacts in downwind states.

14. The lack of a trading option puts non-EGUs at a significant disadvantage when compared to EGUs, is illogical and makes EPA's errors in setting unit-specific emission limits even more critical to the extent many errors result in fatally flawed rule. In addition, EPA has not proposed a case-by-case option for emission units that would be subject to the regulation, whereas almost every prior RACT rule has recognized that emissions and technologies are not fungible and such determination are many times best determined on a case-by-case basis when the general technology and/or limit is shown to be inappropriate or infeasible.

XXI. Due to the Lack of Stakeholder Engagement EPA Fails to Understand the Integrated Steel Making Process.

The Bureau of Industry and Security and Department of Commerce have determined that domestic steelmaking is necessary for our nation's security production requirements and without domestic steel production we run the risk of not being able to adequately respond to a national emergency. In addition, the U.S. Department of Homeland Security has designated steelmakers like U. S. Steel, to be a vital component of our nation's critical manufacturing sector, which is necessary for the economic prosperity, security, and continuity of the United States. The COVID-19 pandemic and the Russian-Ukrainian conflict have highlighted the importance of having robust domestic manufacturing capabilities to supply important products that are essential to national, economic and health security. Therefore, it is imperative that any rulemakings that have the potential to significantly impact the steel industry are accurate and well-grounded in the law and technology. Unfortunately, EPA's Proposed Rule short of these critical criteria.

U. S. Steel has been a critical partner with Federal, State and local governments for over 120 years. Today U. S. Steel employs our "Best For All" strategy where we are diversifying our capabilities and technology through a balance of Integrated Iron and Steel Facilities with scrap to steel facilities using Electric Arc Furnace (EAF) technology. This strategy is critical for U. S. Steel to work towards more sustainable steel production.

In developing the Proposed Rule, EPA did not reach out to U. S. Steel or, to our knowledge, any steel sector stakeholders. This lack of outreach has led to EPA proposing a rule that is illogical and infeasible. In order to truly have a Proposed Rule with positive impacts would require EPA to have a least a minimal understanding of the non-EGU sectors they seek to regulate.

For all of the non-EGU sectors targeted in the Proposed Rule, EPA generically grouped all facilities by the assigned NAICS codes without any attention to the details of the actual facilities, and emission units to be regulated. As discussed within our comments, EPA did not develop emission limits in the Proposed Rule for the emission units to be regulated, but instead attempted to apply a one sizes fits all approach to NAICS code groups like iron and steel facilities. For example, EPA makes assumptions that all reheat furnaces have similar feasibility for emission control technology and the same emission rates even though there are vast differences among the technology and type of reheat furnaces across the iron and steel industry with different emission profiles and emissions

EPA has not clearly explained its screening process in assessing the iron and steel industry. More details are needed for the industry to be able to comment accordingly. For example, in the Proposed Rule, EPA claims that sources with *actual emissions greater than 100 TPY* were assessed, *except well-controlled sources*. However, after reviewing the purported supporting documentation from the docket, it is not clear on what criteria U.S. EPA used to determine if a source was *well-controlled*, and what sources it considered were indeed well-controlled. In addition, EPA states that the rule would apply to any *emission unit* that directly emits or has the *potential to emit* 100 tons per year or more of NOx (and to each BOF Shop containing two or more such units that collectively emit or have the potential to emit 100 tons or more per year or more of NOx. There is a significant difference between actual emissions of over 100 tons and PTE of over 100 tons. In addition, it also appears that a number of emissions units less than 100 TPY actual emissions would inexplicably be covered in the iron and steel category of the Proposed Rule. It is not clear on how or why EPA would include many of the emission units in this category to be subject to FIP limits.

In addition, it is unclear on how BOP Shops are to aggregate emission units; and why and how EPA believes SCR on many of the smaller emission units within a BOP Shop would be appropriate and feasible. For example, BOP Shops generally have a few or several ladle/tundish preheaters. These preheaters are small sources of NOx and NOx controls on these units – even if assumed to be technologically feasible (which it is not)– would not be economically feasible.

XXII. EPA Failed to Determine Technological Feasibility Related to Integrated Iron and Steel Process.

As explained herein when applying RACT, EPA must demonstrate that the proposed limits are both technically and economically feasible on a facility and unit specific basis. And even stricter standards like BACT still require an analysis of technical and economic feasibility. And in any case, EPA has an independent "duty to examine [and justify] key assumptions as part of its affirmative 'burden of promulgating and explaining a non-arbitrary, non-capricious rule. . . .'"[272]

[272] *Appalachian Power Co. v. EPA*, 328 U.S. App. D.C. 379, 135 F.3d 791, 818 (1998).

and EPA may not "promulgate rules on the basis of inadequate data, or on data that, to a critical degree, is known only to the agency."[273] And thus EPA's assumptions regarding feasibility in the Proposed Rule must be adequately justified. EPA has failed to meet its legal burden as it related to the emission limits in the Proposed Rule related to emission units at integrated iron and steel operations.

A. General Issues with the Application of the Proposed Rule to Integrated Iron and Steel Operations.

The Proposed Rule makes erroneous assumption and contains errors that result in fatal issues with its application to the iron and steel industry. The application of the Proposed Rule will require significant operational changes, excessive costs and, in many cases, minimal NOx reductions and actually increases other air pollutants. The SCR technology in the Proposed Rule is not feasible for the sources/emission units in the iron and steel sector that EPA proposes to regulate. Notwithstanding the fact that EPA has not shown if or how iron and steel facilities are contributing to or interfering with ozone attainment in downwind states, even it did, due to the incompatibility of post combustion controls such as SCR/SNCR with many of emission units at integrated iron and steel facilities, EPA's emission limits in the Proposed Rule are not feasible and are therefore unlawful.

EPA has failed to provide support in the Proposed Rule or accompanying technical documents to show that these required emission reductions are actually achievable or, even if they were, how they would result in any measurable improved ozone air quality in downwind states. In many instances equipment and fuels within the steelmaking industry are already low NOx so reductions are not likely to be achieved; and if any further reductions were technologically feasible, they would be cost prohibited as explained in the Trinity Report and the Barr Report. For instance, the Proposed Rule EPA proposes "[f]or a vacuum degasser, NOX is not generated in the process and so NOX control cannot be applied there despite EPA's proposed control. And for an LMF, EPA proposes low NOX burners as a control technology, but there are no burners in an LMF." Again, in its rush to regulate, EPA has proposed a fatally flawed rule that, if promulgated, would lead to illogical, infeasible results at great costs without a required showing of favorable impacts in the downwind states. That being said, U.S. Steel is committed to working with EPA on sound, proven sensible solutions that are technologically and economically feasible and result in measurable ozone improvements in downwind states if, and only if, EPA first demonstrates and shows that the iron and steel industry interferes with ozone attainment in downwind states, which it has not done so in the proposed rule or its purported supporting documents.

Some of the emission units and US Steel's integrated steel facilities to which EPA would have the SCR emission control applied would require significant preconditioning and heating of the exhaust gas to make it amenable to SCR. The conditioning and heating of exhaust gas prior to being able to utilize a SCR would not only be difficult to design and operate but would also require increased use of natural gas and have other impacts and costs not considered by EPA. The

[273] *Portland Cement Ass'n v. Ruckelshaus*, 158 U.S. App. D.C. 308, 486 F.2d 375, 391-93 (1973).

increased combustion of natural gas that would be required to condition the exhaust gas for a SCR would increase various emissions such as CO2, PM, SO2 and even NOx. The increase in NOx clearly goes against the purpose of the Proposed Rule. Nor did EPA consider the design and infrastructure that would be needed for the conditioning and preheating or the environmental impacts associated with the increases in emissions associated with conditioning and preheating. These issues were overlooked or not recognized by EPA during the development of the Proposed Rule.

EPA also failed to fully and accurately develop the costs that would be incurred by the iron and steel industry. The EPA claims that the SCR technology and the limits set in the Proposed Rule would be cost effective but to arrive at that calculation the costs were estimated if technology ran year-round and not just during ozone season (for. Trinity Consultants provides the following information related to their review of the costs associated:

> "For instance, EPA estimates that selection of SCR in the Iron and Steel Mills and Ferroalloy Manufacturing Industry may be associated with 948 ozone season NOx reductions, at an annual cost of $9,886,092. If EPA had calculated the cost per ozone season ton of NOx reduced, this would result in an estimate of $10,428 per ton of NOx reduced, which is well above the cost threshold of $7,500 stated by EPA). But EPA instead, without justification, lists the average cost per ton as $4,345, which would only be the case if the ozone season tons were extrapolated to assume continuous annual reductions."

In the Proposed Rule, EPA started from a limit that was the lowest emission rates identified in any prior RACT or BACT analysis and inexplicable applied additional controls that would lead to arbitrary and unsustainable additional reductions. These reductions were based on control technologies never before applied to these emission units and only based on incorrect generic assumptions. EPA uses similar approaches for the proposed emission limits for all steel units in proposing emission limits far below those determined as either BACT or RACT in unit-specific analyses. This all further supports that EPA used a flawed methodology in the development of the Proposed Rule. We further note that it is illogical and inappropriate for EPA to now require an unjustified, unproven (and infeasible) limit that is significantly lower than BACT or LAER.

B. Application of the Proposed Rule to Specific Integrated Iron and Steel Operations.

The application of the Proposed Rule to various equipment within an integrated iron and steel facility causes many similar issues. This section will address what some of the concerns are with each part of the operations. The issues with the application to the integrated facility are discussed throughout these comments. The emission units discussed below are also discussed in more detail in the Trinity Report found at Exhibit D.

1. Blast Furnace Operations.

The blast furnace converts iron oxide into molten iron for subsequent refining in the BOPF shop to produce steel. A typical burden (feed) may consist of iron ore, pellets, sinter, limestone, coke, mill scale, BOPF slag, and other iron bearing materials. The burden material is charged into the top of the furnace and slowly descends through the furnace. The coke provides the thermal energy required for the process and provides carbon to reduce the iron oxide and to remove oxygen in the form of CO. To U. S. Steel's knowledge, SCRs are not installed on any blast furnaces domestically or internationally, and in the TSD and docket materials, EPA does not cite to any successful application of SCR at any blast furnace ("BF"). This is because SCRs are not technologically feasible as a NOx control for blast furnaces; nor are they cost-effective. U. S. Steel conducted a BART analysis of the BF at Gary Works in 2020 and a RACT analysis at the Edgar Thompson facility in 2014 both of those evaluations indicated the Proposed Rule is not feasible. These are both discussed further in the Trinity comments found in Exhibit D.

BFs use blast furnace gas, coke oven gas, or other heat sources to generate the heat necessary to metal the iron. The use of regenerative heat capitalized on the blast furnace gas ("BFG"). BRG is a low NOx gas and already uses a best practices approach and minimizes the impact on air emission. Any excess BFG is flared to minimize air impacts. EPA seems to fail to realize that the SCR technology is not compatible with a BFG gas flare. If BFG was not used to heat the BF then it would require increased use of natural gas, which would have a negative impact on air emissions.

The application of the Proposed Rule to BFs and the limits established were incorrectly achieved. As stated in Exhibit D, prepared by Trinity Consultants:

> "For blast furnaces, EPA started with an Ohio RACT limitation and then assumed a 50% reduction (from that RACT limitation) based on application of a control technology never before applied to this source type. EPA uses similar approaches for the proposed emission limits for all steel units in proposing emission limits far below those determined as either BACT or RACT in unit-specific analyses. EPA appears to base its approach on an incorrect interpretation of the data in MCM and CoST and does not include any fact-based finding that these technologies are applicable to the steel emission units as part of this proposal."

Emission limits should be set following the application of appropriate regulatory requirements, accurate information, with appropriate control technologies. It appears that none of this was done with the development of the emission limits for the Proposed Rule.

2. Basic Oxygen Process.

Basic Oxygen Process (BOP) is treated differently than all other non-EGU sources. In the other various non-EGU sources there is potential to emit of 100 tpy of NOx as individual emission units to be included in the Proposed Rule. However, BOP operations are required to combine all emission units in determining whether the emission limits in the Proposed rule apply to the emission units at the BOP operations. This combining of emission units results in the application of SCR requirements to potentially very small emission units that do not have an associated stack. Requiring SCR emission controls on units that emit very few tons of NOx per year is overly burdensome, costly and will have no impact on downwind states. The result is illogical.

The BOP is not conducive to the application of the Proposed Rule's SCR technology to decrease NOx emissions. BOPs typically operate with a wet scrubber exhaust system which produces a gas too cool to go into a SCR/SNCR without significant conditioning and heating. Even assuming there is sufficient space, the BOP exhaust system would have to be a completely new design likely to include larger fans and increased duct work. The gas would also have to be heated to temperatures compatible with the SCR resulting in significant, independent NOx emissions. Both of these equipment additions would lead to increased natural gas and electricity usage.

EPA did not consider the costs for redesign of the BOP systems (nor should it as such redesign goes beyond RACT), modification of equipment and process to attempt to work with the SCR requirement, additional equipment needed, additional natural gas, or additional electricity costs. In the EPA's limited understanding of the iron and steel process they also failed to realize that imposing the SCR technology will also lead to emission increases associated with the increased usage of natural gas and electricity. Nothing in the rulemaking docket indicates that EPA considered these costs and impacts; and how the (incorrectly) assumed reductions benefit downwind states.

It is significant to note that EPA has not shown how SCR has been applied on any BOP Shop; and that the anticipated reductions are indeed achievable – technologically and economically. In the TSD, EPA states that it based the emission limit of 0.07 lb/ton of steel on performance testing data from basic oxygen furnaces without NOx reduction controls at integrated iron and steel mills in the United States. EPA then projected what it refers to as a minimal 50% NOx reduction efficiency that EPA, without any support whatsoever, is achievable by use of low-NOx technology, including potential use of FGR and selective catalytic reduction." EPA's rather simplistic approach is that because most BOF vessels and associated BOF Shops in the United States are already equipped with capture technology and existing particulate matter control devices, the NOx reduction technology could simply be integrated to the existing controls. This over-simplification is not supported by fact or law. EPA has not shown that SCR has been successfully applied to BOP Shops. The dynamic conditions in the exhaust gases, including dramatic swings in flow and temperature (e.g., oxygen blow vs. charging or tapping) make SCR inappropriate – and this is supported by the fact that EPA and states/air agencies have never applied SCR to the basic oxygen furnace process shops for any RACT, BACT or LAER determination. However, with the broad stroke in one simple paragraph, EPA, without any support, upends decades of prior determinations, and now inexplicably claims SCR is somehow feasible and appropriate. The TSD is scant on any support – but instead EPA relies on false assumptions.

3. Ladle Metallurgy Furnace.

Ladle metallurgical furnaces (LMF) are used in the steel industry to increase the liquid metal temperature for casting and to produce steel grades by adding alloys. The LMF process is a batch process and since there is no combustion source (except for de minimis amounts associated with the consumption of electrodes by oxidation with oxygen in capture air) there is minimal NOx emissions. In sum, applying SCR at an LMF is inappropriate and illogical. In addition, the application of SCR is not technically feasible, in part due to the batch process of the LMF. Even if one were able to determine how to implement the SCR on a LMF, it would not be cost-effective as it would require an entire redesign of the system and process with de minimis reductions in NOx. Furthermore, because EPA includes LMF as part of the BOP Shop, there is no de minimis threshold for the applicability of the FIP to LMFs (assuming that the BOP Shop's PTE (from all units within the shop) is 100 tons or more. This is illogical – so illogical that the cost effectiveness would be approach \$2 million per ton of NOx removed – several orders of magnitude of EPA's purported cost threshold of \$7,500/ton. Furthermore, EPA has not shown how LMFs (individually or aggregately with other emission units) interfere with ozone attainment in downwind states; nor has EPA shown how the emission limits for LMFs would lead to any measurable benefits in ozone in downwind states.

4. Degassers.

EPA appears to have a fundamental misunderstanding of vacuum degassing and NOx emissions (de minimis) associated with the process. Vacuum degassers (VDGs) are used in the steel industry to remove certain gases from the molten steel prior to casting. This helps to produce the desired properties of the finished steel. Degassers can remove hydrogen (H_2), oxygen (O_2), and nitrogen (N_2) that are dissolved in the liquid metal. They are also used to reduce the carbon content of the steel prior to casting to produce an ultra-low carbon product.

While not clear from Proposed Rule, it would appear that EPA would intend to include vacuum degassing in the BOF Shop, and therefore, not subject to the triggering 100 ton PTE threshold, and, instead, would inexplicably be included and subject to the proposed limits even if no appreciable reduction would result. The process of the degasser itself does not generate NOx – and therefore its inclusion in the proposed rule is perplexing. The only NOx associated with vacuum degassing is NOx generated by the flare when CO abatement and is a function of adiabatic flame temperature which is related to excess air, fuel usage and flare design. EPA's has scant support for its inclusion of vacuum degassing and the proposed limit of 0.03 lb/mmbtu on existing permit limits of 0.05 lb/mmbtu. (EPA's entire technical support discussion in the non-EGU TSD for the limit is provided below:

> "For vacuum degassers utilized in secondary steelmaking, EPA based the limit of 0.03 lb/mmBtu on existing permit limits of 0.05 lb/mmBtu. EPA projects minimally 40% NOx reduction efficiency is achievable by use of low-NOx technology, including use of selective catalytic reduction."

EPA does not provide any further explanation – and a review of the RBLC does not support EPA's ambiguous and vague conclusions.

Installing emission control technology on VDGs is not feasible. VDGs are a batch process and has variables in the exhaust gas. Again, due to the de minimis amounts of NOx peripherally associated with vacuum degasser flares and the low potential reduction of NOx from installation of SCR technology (even if it were feasible, which it is not) results in a technologically infeasible limit that is not cost-effective. VDGs also are very low in NOx emissions and do not meet the 100 ton per year threshold in the Proposed Rule. However, the VGDs are inexplicably pulled into the aggregated numbers of the BOP or BOF emissions

5. Ladle/Tundish Preheaters.

Ladle or Tundish preheaters are small natural gas burners that direct fire ladles to keep them warm, dry or preheat them – as an ancillary process and to better preserve refractory. The preheaters are used to dry out ladles and there is no vent or combustion exhaust gas capture. In this case SCR technology is not feasible as there is nothing to add the SCR to at the end of the exhaust. EPA failed to understand the use of these preheaters and did not make any determination as the feasibility of putting SCR on the ladle or tundish preheaters. If the Proposed Rule is finalized there would be significant costs in trying to absolutely redesign these preheaters to accommodate the possibility of SCR.

Ladle preheaters are such a small potential source of NOx that there will be no impact from this change on downwind states. Most states already consider this to be an insignificant activity for air emissions and consider it fugitive emissions.

The gas burners on the preheaters are very small with heat inputs of typically 5-15 MMBtu/hr. In addition, the preheaters are needed to be mobile so that they can be use don ladles throughout the shop. The very small heating value, coupled with the de minimis NOx emissions from ladle preheating, and the inconsistent and mobile operation makes SCR technologically infeasible. And even if SCR were technologically feasible, which it is not, it would not be economically feasible, as even if the emissions from the units were able to be captured in a hood and treated, the cost estimate of nearly $50,000/ton of NOx removed, not including any costs associated with hooding and other infrastructure needed to accommodate the technology. Simply, the proposed limit based upon application of SCR is perplexing.

The ladle preheaters are very low in emissions and do not meet the 100 ton per year threshold in the Proposed Rule. However, the preheaters are inexplicably pulled into the aggregated numbers of the BOP or BOF emissions. Any potential reduction from ladle or tundish preheaters would be minimal and would not be cost-effective. Furthermore, EPA has not shown how the insignificant NOx emissions from ladle/tundish preheaters interfere with ozone attainment in downwind states; or how downwind states would have any measurable benefit from the proposed limits. Again, there appears to be a fundamental misunderstanding of the industry and the limitations of the proposed SCR technology to these sources.

6. Hot Strip Mill Operations/Reheat Furnaces.

Hot Strip Mills are specifically designed operations, and any addition of equipment or technology requires significant planning, engineering, time, and money. EPA's failure to understand the complicated operations at a hot strip mill has led to the Proposed Rule significantly underestimating the difficulty that would be involved in retrofitting the prescribed emissions control equipment in the Proposed Rule. The cost and ability to retrofit equipment within a hot strip mill is going to be extremely difficult and require significant modification to operations. A retrofit of this nature will also cause significant downtime and associated loss of revenue. The proposed SCR technology if it is even capable of being installed will require extensive modification to accommodate the changes.

The U. S. Steel Gary Works facility as well as other facilities have completed a RACT analysis for hot strip mill operations related to Regional Haze. Operations at these facilities have already been modified to meet the RACT requirements. The Proposed Rule attempts to regulate beyond the requirements already in place, through what can only be characterized as a "beyond-LAER" emission limit. LEAR. All of the changes (for all integrated iron and steel operations) in the Proposed Rule will have a minimal impact on attainment in downwind states. Continuing to push for unproven and very costly technology to be applied with little to no appreciable improvement is not the purpose of this section of the CAA.

Reheat furnaces are used to reheat slabs of steel to work and shape the steel into another product. The reheat furnaces use uniform heat and hold the desired temperature for a set time. The design and operation of reheat furnaces makes SCR technology infeasible.

The U. S. Steel Irvin Works evaluated RACT for a reheat furnace in 2014. Trinity Provides an overview in Exhibit D. However as expected "That analysis found that the cost of adding low NO_X burners would be $14,100/ton, which is not cost effective." The U. S. Steel Gary Works facility then conducted a BART analysis for reheat furnaces in 2020. The BART analysis found that the cost of adding low NO_X burners would be $14,100/ton, which is not cost effective under the purported cost threshold of $7,500 that EPA arbitrarily set forth iron and steel units in the Proposed Rule. Due to the heat needed these burners would likely increase the energy use as well. Creating another expense and likely increasing air emissions.

Again, EPA fails to understand the iron and steel industry and does not show that the Proposed Rule meets its purpose to improve air emissions related to NOx.

7. Annealing Furnaces.

Annealing furnaces go through a series of heating and cooling process allowing hard metals to have various ductility and strength. Annealing furnaces are designed to operate in a batch or continuous function. Continuous Annealing furnaces are the only steelmaking equipment that has been shown to be feasible with the SCR technology. However, SCR is not feasible on batch annealing furnaces.

While the SCR technology may be technologically feasible for continuous annealing furnaces it is not cost effective. Trinity Consultants performed a "control cost effectiveness analysis on the Irvin open coil annealing furnace, which showed that the SCR cost effectiveness would be at best $25,630 (2021$). This is well beyond the EPA stated $7,500.

EPA also did not use the proper methodology to set emission limits for the annealing furnaces. There is additional technical information in the document prepared by Trinity Consultants which states "for annealing furnaces, EPA started with recent BACT determinations, and then applied an additional 40% reduction without any demonstration of achievability of the proposed limit." These numbers are not based upon proper determinations and EPA did not provide support for the additional 40% reduction found in the Proposed Rule.

8. Boilers

Boilers used at integrated iron and steel facilities vary greatly as will the NOx emission rates. These boilers will also have a variety of fuel sources and operating parameters. Each boiler would have to be evaluated as to the potential to reduce NOx emissions, the technical feasibility of SCR and the cost effectiveness.

U. S. Steel conducted a BART analysis on the Clairton facility boilers in 2022. That analysis showed the SCR annual cost effectiveness was at minimum $20,873/ton on Boiler 2, and more expensive on others. Additional review has been done at other U. S. Steel facilities and that information is provided in the Trinity Report in Exhibit D.

Some of the boilers already combust BFG which is low NOx and considered a best practice. This is significantly better from an environmental perspective than an alternative like natural gas that would displace the BFG and increase air emissions. Any modification of boilers would require significant modification to attempt to accommodate SCR. This would not only be costly but would likely produce negative air impacts, especially if boilers were switched to natural gas.

Boilers are yet another area where EPA need to evaluate in more detail, likely through a separate rulemaking or individual RACT determinations, in order to justify the emission limits, it purports to apply "wholesale" to boilers in the Proposed Rule.

SPECIFIC COMMENTS PERTAINING TO MINNESOTA MINING OPERATIONS

XXIII. Minnesota Should Not be Regulated in the Proposed Rule.

Minnesota is not having a significant impact on downwind air quality. Minnesota was identified as a non-significant contributor (below 0.7 parts per billion) to any ozone monitors in the 2018 modeling performed by both EPA and LADCO. Minnesota's original submittal should have been approved based on contribution information available from both EPA and LADCO at that time.

While EPA now maintains that, with new modeling, it has found contributions in excess of 0.71 ppb at two monitors, EPA's position that this alone is sufficient to subject Minnesota to regulation is based on an overly-conservative assumption that a 1% threshold is sufficient to justify regulation of downwind ozone impacts.

Breaking out the sources of the receptor impacts EPA modeled shows that the regulated emissions from Minnesota are having less than a 0.3 ppb impact on down-wind monitors.

2026 MN-Specific Scenario	Total Ozone (ppb)	State Impacts (ppb)	Non-EGU (ppb)	EGU (ppb)
Illinois (001) Results (ppb)	72.5	0.91	0.19	0.04

Illinois (076) Results (ppb)	71.3	0.75	0.18	0.03

In other words, eliminating all non-EGU and EGU emissions from Minnesota would not affect Illinois' attainment status.

If the sources being evaluated for controls are not providing a reduction that would have any appreciable impact on attainment or maintenance of the NAAQS, then EPA cannot support regulating those emissions as "amounts which will—(I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard." 42 U.S.C. § 7410(a)(2)(D)(i)(I); *see also EPA v. EME Homer City Generation, LP*, 134 S. Ct. 1584 (2014) ("EPA cannot require a State to reduce its output of pollution by more than is necessary to achieve attainment in every downwind State or at odds with the one-percent threshold the Agency has set. If EPA requires an up-wind State to reduce emissions by more than the amount necessary to achieve attainment in every downwind State to which it is linked, the Agency will have overstepped its authority, under the Good Neighbor Provision, to eliminate those "amounts [that] contribute ... to nonattainment.").

Simplified assumptions are sometimes appropriate and necessary in a complex modeling analysis such as a national photochemical ozone evaluation. However, when the results are used to justify costly controls and monitoring on a significant number of industrial operations in the state, further culpability refinements need to be assessed. Arbitrarily requiring controls across multiple non-EGU facilities in a state contributing more than 0.71 ppb to a modeled ozone value greater than 70 ppb demands an extra step confirming that the specific non-EGU sources EPA seeks to regulate are in fact significant contributors from each state.[274] Again, looking at the impacts modeled for the State of Minnesota, the maximum modeled impact is less than 1 ppb.

MN	Keetac, Minntac	Cook (1), IL: 73.4 Cook (76), IL: 72.1	Cook (1), IL: 0.97 Cook (76), IL: 0.79	Cook (1), IL: 72.5 Cook (76), IL: 71.3	Cook (1), IL: 0.91 Cook (76), IL: 0.75

As discussed in the above Section VI. G titled "Improper Significance Screening Threshold," no impact below 1 ppb can be considered significant, due to EPA's 2018 guidance finding that a 1 ppb threshold is generally comparable to a 1% threshold for the 2015 ozone NAAQS in terms of the contributions it would cover, 1 ppb being the lowest significant digit used for reporting ozone monitoring data under the NAAQS, and EPA previously determining based on statistical analysis underlying the Ozone SIL that no contribution below 1 ppb can have a

[274] In fact, as discussed previously, there is no statutory justification for EPA to group unrelated industries together as a lump title of "non-EGU" sources for purposes of evaluating the significance of impacts, and it is arbitrary to lump all such industries together when EPA provides industry specific consideration to the EGU industry. EPA must evaluate the significance of the particular sources is seeks to subject to the rule if it wishes to impose facility or unit specific emission controls. If on the other hand EPA wishes to create an emissions trading regime similar to that currently in place for EGUs, EPA must at minimum demonstrate that any industries included in such trading regimes are significant contributors to each specific state's linked receptors.

significant impact on a downwind receptor. Based on this limited impact at even the maximum modeled influence on receptors, EPA's argument that Minnesota emissions need to be controlled for future ozone NAAQS demonstration based on a maximum contribution of between 0.75 and 0.97 ppb is not justifiable.

EPA's decision to regulate Minnesota based on a maximum modeled contribution of 0.97 ppb rather than EPA's guidance threshold of 1 ppb also is particularly troubling because the model EPA is using lacks the consistency and accuracy needed to make such fine-grained distinctions. Rather, based on EPA's own assessment in the modeling TSD, "the regional mean bias of the model is +/- 5 ppb and the mean error is between 6 and 7 ppb on average for all days during the period May through September in each region."[275]

	Model/Obs. (ppb)	Mean Bias (ppb)	Mean Error (ppb)	Standard Deviation (ppb)
Cook County, IL (001)	60.75/68.97	-8.22	11.13	8.16
Cook County, IL (076)	57.87/67.77	-9.90	11.85	8.65

These numbers challenge the assumption in the Proposed Rule that emissions from Minnesota are "significant." It is simply insupportable to assert that unprecedented and costly emission reductions are needed to achieve an impact on down-wind monitors that is less than the error in EPA's model.

XXIV. Taconite Should Not be Regulated in the Proposed Rule.

Taconite is not part of the Iron and Steel and Ferroalloy Manufacturing Industry Group. EPA's modeling analysis of contributions from non-EGU emission units was conducted on an industry-group basis, based on 4-digit NAICS codes.[276]

EPA created two "tiers" of industry groups. *Id.* The first tier includes four industries that EPA proposes it "should focus the assessment of NOx reduction potential and cost primarily on": pipeline transportation of natural gas; cement and concrete product manufacturing; iron and steel mills and ferroalloy manufacturing; and glass and glass product manufacturing. *Id.* The preamble to the Proposed Rule appears to include "Taconite production kilns" as a source in the Iron and Steel and Ferroalloys Manufacturing Industry Group.[277] Further, the proposed language of 40 CFR § 52.43, which applies to Iron and Steel Mills and Ferroalloy Manufacturing is proposed to include in the definition of "Affected unit" "taconite production kiln."[278]

[275] Air Quality Modeling Technical Support Document, EPA-HQ-OAR-2021-0668-0099 at A-7.

[276] 87 Fed. Reg. at 20,083; see also EPA-HQ-OAR-2021-0665-0191, at 1.

[277] 87 Fed. Reg. 20,046, Table IV.B-4; *id.* at 20,145, Table VII.C-3.

[278] 87 Fed. Reg. at 20,181.

To the extent EPA is including taconite kilns in the Proposed Rule because they are part of "iron and steel mills and ferroalloy manufacturing," this is incorrect. Taconite production is not part of iron and steel or ferroalloy manufacturing. The modeling underlying the Proposed Rule categorizes emission units based on the NAICS Code of the subject facilities. The NAICS code for iron and steel manufacturing is 3311. Metal ore mining, including taconite production, has NAICS code 2122. This is documented in EPA's own modeling data from September 29, 2021. Section 2.5.2 of the RIA describes the industry EPA intended to regulate in the Iron and Steel Mills and Ferroalloy Manufacturing NAICS code:

> Iron is produced from iron ore, and steel is produced by progressively removing impurities from iron ore or ferrous scrap. ***The first step is iron making.*** Primary inputs to the iron making process are iron ore or other sources of iron, coke or coal, and flux.

(emphasis added). This description does not include mining or processing of taconite prior to the iron making process.

It is arbitrary to include taconite kilns in the Proposed Rule because EPA has not modeled the significance of their contribution to any downwind receptor as would be required. Taconite production is not separately mentioned in the Non-EGU Screening Assessment which is EPA's sole basis for determining which industries had a significant enough impact relative to subject to the Proposed Rule. EPA states that that modeling was done on the basis of NAICS code, which would mean that taconite kilns were not included in the modeling of the contributions from the Iron Steel and Ferroalloy industry since as noted above taconite production belongs to a different NAICS code. This is confirmed by the fact that there appear to be no taconite kilns listed in the list of facilities and emission units evaluated as part of the Non-EGU Screening Assessment.[279] Because taconite production was never modeled to be a significant contributor to downwind nonattainment or maintenance issues, it cannot be regulated under the Good Neighbor provision of the CAA. Furthermore, there is no rational basis to treat Taconite as part of the Iron and Steel and Ferroalloy Manufacturing Industry Group. Taconite production is not co-located with iron and steel manufacturing. As a result, there are no taconite production kilns "at an iron and steel mill or ferroalloy manufacturing facility."[280] Taconite production does not use similar processes, have similar emission profiles, or use similar pollution controls. There is no factual basis to conclude that taconite production and iron and steel manufacturing have similar impacts on down-wind receptors, similar costs of pollution controls, or should otherwise be grouped together for purposes of screening or regulation under the Proposed Rule.

XXV. Taconite Was Properly Eliminated from EPA's Screening Assessment as a Tier 2 Source Without Significant Boiler Emissions.

[279] Non-EGU Screening Assessment at Table 6; see also excel file in regulatory docket titled "Screening Assessment Non-EGU Facility and Emission Unit Limits List".

[280] *Id.*

While there is no rational basis to include taconite kilns in the Iron and Steel and Ferroalloy Manufacturing Industry Group, EPA did evaluate the Taconite Industry as part of the Metal Ore Mining Industry Group in its Screening Analysis. In doing so, Taconite was appropriate *excluded* from the Proposed Rule.

Specifically, in the "Non-EGU Screening Assessment," the Metal Ore Mining Industry (4-digit NAICS 2122) was originally included as a Tier 2 industry group; however, in a later step in the analysis EPA refined the Tier 2 grouping by identifying potentially impactful industrial, commercial, and institutional ("ICI") boilers, using the projected 2023 emissions inventory in the linked upwind states. This eliminated the Metal Ore Mining Industry Group from the assessment entirely, as EPA found that it had no "potentially impactful" boilers.[281]

Based on EPA's own assessment, therefore, boilers in the Metal Ore Mining industry, which would include the Taconite Industry, do not provide opportunities for NOx emissions reductions that result in meaningful impacts on air quality at downwind receptors.

XXVI. There is No Other Support in the Record for Subjecting the Taconite Industry to Regulation.

The record is notably lacking in any analysis that would support including the Taconite Industry, on its own or as part of the Iron and Steel and Ferroalloy Manufacturing Industry.

As EPA explains in the preamble to the Proposed Rule, "for Taconite Production Kilns, the EPA does not currently have the data to determine appropriate emissions limits that these units could achieve by installing low NO_X burners. Therefore, the EPA is proposing to require the installation of low NO_X burners for Taconite Production Kilns and work practice standards for operating these control technologies to achieve emissions reductions. The EPA is also proposing to require these sources to perform performance tests and establish a unit-specific emissions limit at that time. These work practice standards are consistent with EPA's Taconite FIP for Minnesota.[282] Due to the ongoing nature of this FIP, the EPA is proposing to require installation of specific control technologies and a period of evaluation before setting a numerical emissions limit."[283] This is just another way of saying EPA does not have sufficient data to impose emission regulations and that this data, and the regulations themselves, will come from the Taconite FIP. If EPA lacks the data to regulate now, the only option is to exclude Taconite from regulation. EPA cannot promulgate a "placeholder" rule that simply says EPA will regulate later.

EPA has also not done any of the assessments for Taconite that have been included to support the Proposed Rule for other sources. The data EPA used for its screening assessment did not include taconite kilns.[284] EPA's Screening Assessment identified 489 emission s units with

[281] Screening Assessment at 5; *see also id.* at 6, Table 1: Number of Emissions Unit Types in Tier 2 Industries in the Non-EGU Screening Assessment.

[282] See 81 FR 21671 (April 12, 2016).

[283] 87 Fed. Reg. at 20,146.

[284] EPA-HQ-OAR-2021-0668-0191 Attachment 1.

greater than 100 tpy of NOx emissions at approximately 250 facilities, none of which were taconite kilns or taconite facilities. EPA's estimates of costs did not look at taconite facilities.

Had EPA looked at the costs of regulating the Taconite Industry, it would have been forced to reject the $7,500/ton threshold suggested by its modeling. Barr has completed an initial draft cost estimate for a retrofit installation of low-NOx burners on one of the U.S. Steel Minntac's Step III 153 MMBTU/hr Natural Gas-Fired Heating Boilers using the Proposed Rule's NOx emission limit for Natural Gas Fired Boilers of 0.08 lb/MMBTU. The preliminary cost estimate shows that if one of Minntac's Step III 153 MMBTU/hr Heating Boilers was retrofitted with a low-NOx burner, the resulting pollution control cost would be ~$20,000/ton of NOx removed, which exceeds EPA's cost effectiveness threshold of $7,500/ton. EPA's benefits calculations (EPA-HQ-OAR-2021-0668-0134) did not look at benefits from regulating taconite kilns. EPA's examination of ongoing compliance costs did not look at taconite facilities.[285] Without the relevant data and a satisfactory explanation for its actions, EPA cannot include the Taconite Industry in regulations that are otherwise completely focused on other sources.

XXVII. Excluding Taconite from the Proposed Rule is Proper Because the Proposed Rule Imposes No Limits on the Industry.

NOx emissions from taconite kilns are already regulated by detailed regional haze FIPs covering Minnesota and Michigan.[286] This FIP imposes stringent NOx emission limits based on the installation of low-NOx main burner systems as the best available retrofit technology ("BART"), with specific emission limits and implementation schedules established for each taconite facility based on its own historic performance and retrofit capabilities. Minnesota has noted in prior comments that the Taconite FIP is already responsible for just under 11,000 tons per year in NOx reductions in the State, including 5,700 tons per year from U. S. Steel's Keetac and Minntac facilities.[287] This is a demonstration of the considerable environmental improvements that have already been achieved in Minnesota air quality and interstate transport of NOx from Minnesota. The Proposed Rule recognizes the effectiveness of the Taconite FIP, pointing to the FIP requirements as the very requirements needed by the Taconite industry "to achieve the required emissions reductions [to satisfy the] remaining interstate transport obligations for the 2015 ozone NAAQS."[288] Even if the Taconite Industry were subject to regulation under EPA's Screening Assessment, this finding would support excluding the Taconite Industry from further regulation, because there are no further restrictions needed to prevent significant contribution to nonattainment or interference in maintenance of the ozone NAAQS, and EPA is not permitted to over-control sources.[289]

[285] Information Collection Request, EPA-HQ-OAR-2021-0194 at 4 and 11-12.

[286] 40 CFR §§ 52.1235 and 52.1183 (the "Taconite FIP").

[287] Minnesota SIP Denial Comments at 2.

[288] 87 Fed. Reg. at 20,045.

[289] *EPA v. EME Homer City Generation, LP*, 572 U.S. 489 (2014).

Minnesota has itself urged EPA to "have these significant reductions included in the 2016v2 inventory for non-EGUs" rather than take credit for them in the new FIP.[290] But EPA does not draw the right conclusion from the results of the Taconite FIP. No other non-EGU is subject to this type of double-regulation in the Proposed Rule, and EPA provides no justification for singling out taconite kilns in the Proposed Rule. As with other industries that are not Tier 1 sources and do not have large boilers subject to Tier 2, the Taconite Industry should be excluded from the Proposed Rule.

XXVIII. The Proposed Rule Should Not Incorporate Another FIP by Reference.

As discussed above, the Taconite Industry is already subject to stringent NOx regulations by the Taconite FIP. EPA proposes to re-impose these same requirements in the Proposed Rule, essentially double-counting reductions that have already been mandated by the State of Minnesota and EPA. Specifically, the Proposed Rule nominally includes taconite kilns, erroneously categorized as part of the Iron and Steel and Ferroalloy Manufacturing Industry, but the emission limits in the Proposed Rule for taconite kilns are "Work practice standard[s] to install low NOx technology/burners, test and set."[291] This requirement is explained as being imposed because it is "[c]onsistent with requirements in Minnesota Taconite FIP *See* 81 FR 21671."[292] The proposed rule language is even more explicit, stating that Taconite Production Kilns are to "Install and operate low NOX burners as required by 2013 and 2016 Minnesota FIPs. 40 CFR § 52.1183." 87 Fed. Reg. at 20,181, Table 1 to Paragraph (c).[293] In other words, the Proposed Rule does not impose emission limits on the Taconite Industry. It only incorporates requirements from the already-imposed FIP.

Taking a FIP that has already been imposed for regional haze and recasting it in duplicate form as an ozone transport requirement is inefficient and inappropriate. Rather than imposing a redundant Taconite FIP requirement in the Proposed Rule, EPA should find that, considering the Taconite FIP, no further regulation of the Taconite Industry is needed to address.

XXIX. If EPA Ultimately Incorporates the Taconite FIP in the Proposed Rule, it Must Accurately Reflect the Requirements of the Taconite FIP.

Including the Taconite Industry in the Proposed Rule is at best redundant with the Taconite FIP. At worst, the Proposed Rule will conflict with the Taconite FIP it purports to incorporate, creating confused and potentially inconsistent requirements.

In the Taconite FIP, EPA attempted to impose a single uniform emission limit across all taconite kilns. This resulted in over ten years of litigation, which is still ongoing, and multiple

[290] Minnesota SIP Denial Comments at 2.

[291] 87 Fed. Reg. 20,046, Table I.B-4 and 20,145, Table VII.C-3.

[292] *Id.* at Table VII.C-3.

[293] The Proposed Rule's citation is incorrect. 40 CFR § 52.1183 is the Michigan regional haze FIP. The Minnesota FIP is at 40 CFR § 52.1235. This reference also ignores the 2021 Minnesota FIP, which addressed Minntac. See 86 Fed. Reg. 12,106 (March 2, 2021).

revisions to the Taconite FIP to incorporate the unique circumstances of each facility.[294] Additional revisions are anticipated following negotiation of revised language for U. S. Steel's Keetac facility.

In attempting to paraphrase the Taconite FIP in a single line, the Proposed Rule falls into the same error. The Proposed states that taconite kilns will "install, maintain, and continuously operate low-NO_X burners to reduce existing average NO_X emissions from the facility by 40% during all periods of kiln operation."[295] This language is nowhere in the Taconite FIP. Rather, the Taconite FIP sets out a detailed and comprehensive plan for establishing achievable emission limits for a variety of taconite production kilns. Minnesota has itself estimated that reduction from low-NOx burners to range from 2%-65% based on the emission unit.[296]

The language used in the Proposed Rule is also far too vague to serve as a regulatory requirement. The Proposed Rule provides no process for calculating "existing average NO_X emissions from the facility."[297] The Proposed Rule provides no support for its derivation of a 40% NOx reduction at all taconite kilns. As noted above, EPA previously attempted to impose uniform emission limits on all taconite furnaces. The result was ten years of litigation and multiple rounds of rulemaking revisions to arrive at case-by-case, unit specific emission limits for the taconite industry that have been demonstrated achievable based on actual emissions data.

The Proposed Rule does not recognize that Minntac's Taconite FIP requirements were expressly negotiated to be an aggregate emission limit across five kilns, not a single reduction at each kiln.[298] The Proposed Rule improperly directs that a specific technology by used at taconite kilns (low-NOx burners). In both the Taconite FIP and for all other sources in the Proposed Rule, emission limits are set based on available technologies, but each source is free to achieve the limit based on any combination of emission controls. For facilities that have not yet installed low-NOx burners, the Proposed Rule provides for using data from "within five years of the effective date of this rule to be used as baseline emission testing data providing the basis for required emission reductions."[299] This ignores the test-and-set schedules established in the Taconite FIP for many facilities.[300] U. S. Steel and EPA are currently negotiating a revised limit for Keetac that would include its own implementation schedule, which may or may not match that of the Proposed Rule.

The operating, monitoring, and recordkeeping requirements in the Proposed Rule are all drafted on the assumption that there is an applicable emission limit for the regulated unit. Requirements that a facility use CEMS to "monitor compliance with the emissions limits set forth

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[294] *See* 81 Fed. Reg. 21,687 (April 12, 2016); 86 Fed. Reg. 12,106 (March 2, 2021).

[295] 87 Fed. Reg. at 20,182.

[296] EPA-R05-OAR-2022-0006-0011-attachment_1.

[297] 87 Fed. Reg. at 20,182.

[298] *See* 40 CFR 52.1235(b)(iii).

[299] 87 Fed. Reg. at 20,182.

[300] *See, e.g.*, 40 CFR 42.1235(b)(ii)(A)(2).

in Table 1 to paragraph (c) of this section," or record 30-day averages "in excess of the applicable NOx emission limit in Table 1 to paragraph (c)" do not make sense if there is no numeric emission limit imposed in Table 1 to paragraph (c).[301] Similarly, the Proposed Rule's requirement that taconite kilns "continuously operate NOx control devices as necessary to achieve emission limits set forth in Table 1 to paragraph (c) of this section" makes no sense in the context of the Taconite FIP.

Finally, the Proposed Rule goes beyond EPA's authority when it requires taconite kiln operators to "continuously operate low-NOx burners to reduce existing average NO_X emissions from the facility by 40% during all periods of kiln operation" in order to prevent contribution or interference with an ozone NAAQS that are justified throughout the rulemaking only for the ozone season.

The Proposed Rule not only needlessly restates requirements that are already reflected in the Taconite FIP, it adds confusion and either undoes, or redoes, without sufficient information or support, evaluations and productive efforts that have occurred for over 10 years and that have resulted in significant NOx reductions that have been shown to be technologically and economically feasible. This is needless overregulation and should be removed from the Proposed Rule.

XXX. Minntac and Keetac Modeling Corrections Are Required

Minntac is modeled to emit 3,900-4,167 tpy from 2032 to 2023. September 29, 2021, Emissions Data. Minntac has already committed, as reflected in its 2013 title V permit, to reduce emissions to 3,990 tpy as an annual cap on all facility NOx emissions.

Keetac is project to emit 4,631-4,949 tpy. According to the 2016 Barr Engineering analysis submitted to EPA, baseline calculations of Keetac data should not be based on recent emissions data because it is not representative of the mix of fuels the Keetac furnace is permitted to burn. Even so, a far more representative baseline is 3,455 tpy for uncontrolled NOx emissions.

SPECIFIC COMMENTS RELATED TO STATE IMPLEMENTATION PLANS

XXXI. The Proposed Rule Does Not Provide Adequate Deference to State Approaches to Regulation of Interstate Transport of NOx, as Required by the Principles of Cooperative Federalism Contained in the Clean Air Act.

State primacy in developing implementation plans and the opportunity to cure perceived defects in implementation plans are two examples of a broader theme of cooperative federalism that runs throughout the Clean Air Act. *See Bell v. Cheswick Generating Station*, 734 F. 3d 188, at 190 (3rd Cir. 2013) (The Clean Air Act "employs a 'cooperative federalism' structure under which the federal government develops baseline standards that the states individually implement and enforce."); *Michigan v. EPA*, 268 F.3d 1075, 1083 (D.C. Cir. 2001) (the Clean Air Act "is an experiment in cooperative federalism"); *see also Am. Trucking Ass'ns v. EPA*, 600 F.3d 624, 625

[301] 87 Fed. Reg. at 20,182.

(D.C. Cir. 2010) (under the Clean Air Act, "both the Federal Government and the States . . . exercise responsibility for maintaining and improving air quality"). As Justice Kennedy stated in dissent in *Alaska DEC v. EPA*:

> If cooperative federalism is to achieve Congress' goal of allowing state governments to be accountable to the democratic process in implementing environmental policies, federal agencies cannot consign States to the ministerial tasks of information gathering and making initial recommendations, while reserving to themselves the authority to make final judgments under the guise of surveillance and oversight.

540 U.S. 461, 518 (2004) (internal citation omitted).

In proposing the FIP, EPA totally obviated Congress' intentions that the Clean Air Act be implemented across the county in a manner that uses cooperative federalism. Instead, EPA unilaterally rejects the State's approaches to regulating interstate transport of NOx originating within their borders, and would impose EPA's own, unproven and infeasible, preferred approach to fulfil the Clean Air Act ozone transport requirements. In doing so, EPA improperly treated the state SIPs are mere "initial recommendations" over which EPA could impose its own "final judgments under the guise of surveillance and oversight."

No state has proposed the type, scope, or stringency of emission limitations contained in the Proposed Rule. This is particularly notable in the context of the NAAQS, which do not require limitation of any particular industry, emission source, or use of any particular control technology to achieve the interstate transport obligations of CAA § 110. This wholesale rejection not just of the states' findings, but their entire approach to regulating emissions within their borders, particularly when combined with the lack of any opportunity for the states to reasonably comment on the denials of their SIPs and amend them in light of EPA's perceived deficiencies, demonstrates a lack of deference to the fundamental principles of cooperative federalism embodied in the Clean Air Act and further cautions against EPA proceeding with the Proposed Rule.

XXXII. EPA is Exceeding its Statutory Authority by Issuing the FIP while Disregarding Approvable SIPs.

EPA does not have authority to impose a FIP when adequate and approvable SIPs have been submitted to EPA.

Under the Clean Air Act, states are given primacy in developing implementation plans for compliance with the national primary and secondary ambient air quality standards. *See* 42 U.S.C. § 7410; *see also Train v. NRDC*, 412 U.S. 60, 79 (1975) (EPA is "relegated by the [Clean Air] Act to a secondary role in the process of determining and enforcing the specific, source-by-source emission limitations which are necessary if the national standards it has set are to be met."). This includes meeting the interstate transport requirements of "prohibiting, consistent with the provisions of this subchapter, any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—(I)contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard, or (II)interfere with measures required to be included in the applicable implementation plan for any other State under part C to prevent significant deterioration of air quality or to protect visibility." 42 U.S.C. § 7410(a)(2)(D)(i).

Only when the state does not submit a compliant SIP, and the Administrator either "(A) finds that a State has failed to make a required submission or finds that the plan or plan revision submitted by the State does not satisfy the minimum criteria established under subsection (k)(1)(A), or (B) disapproves a State implementation plan submission in whole or in part," does EPA have authority to promulgate a FIP. 42 U.S.C. § 7410(c); *see also Train*, 412 U.S. at 79 ("Under § 110(a)(2), the Agency *is required* to approve a state plan which provides for the timely attainment and subsequent maintenance of ambient air standards, and which also satisfies that section's other general requirements.") (emphasis added).

Nineteen states, including the states of Arkansas, Illinois, Indiana, Michigan, Minnesota, Ohio, and Pennsylvania, have submitted SIPs that meet the requirements of the Clean Air Act and should be approved. Instead of meeting its statutory obligation to review these previously-submitted SIPs, EPA ignored them for years. Now, subject to a short deadline imposed under a consent decree, EPA proposed wholesale disapprovals of these plans without adequate justification and contrary to the mandate of § 110(a)(2) of the Clean Air Act shortly before proposing the FIP in the Proposed Rule.

EPA has not yet finalized its disapprovals and has given the states no opportunity to correct any deficiencies that EPA purports they contain. While EPA has found that some states have not submitted SIPs, for many states, EPA has only proposed disapproval or is still reviewing the state plans. 87 Fed. Reg. at 20,040 (for certain states, "the EPA has proposed, but has not finalized, actions disapproving good neighbor SIP revisions. And for other states, the EPA has not yet proposed action on their good neighbor SIP submittals, but these submittals are currently under review, and EPA intends to act on these submittals in the coming months"). In doing so, the Proposed Rule improperly supplants states' primary authority and would put EPA's preferred ozone approach over the states' own adequate and approvable implementation plans. This is beyond EPA's authority.

EPA's proposed denial of the SIPs is addressed at length in the comments submitted on EPA's proposed SIP denials, including U. S. Steel's own comments on the proposed denials of the Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin SIPs (EPA-R05-OAR-2022-0006-0017) and the Arkansas SIP (EPA-R06-OAR-2021-0801-0043). These comments are equally relevant to the Proposed Rule, and U. S. Steel incorporates them by reference.

As demonstrated in those comments, EPA's proposed SIP denials are not based on proper grounds. Rather, they are based on:

1. Improperly rejecting state assessments of whether in-state emissions were significantly contributing to or interfering with maintenance of downwind attainment of the ozone NAAQS that were not only well within the State's discretion as primary regulators, but consistent with EPA's own published guidance.

2. Moving the goal posts for regulation by creating new modeling after SIPs were already submitted, creating a standard no state could possibly meet.
3. Erroneously relying on incomplete and inaccurate emissions data.

Correcting these issues will demonstrate that EPA does not have grounds to disapprove the previously-submitted SIPs, including the SIPs or Arkansas, Illinois, Indiana, Michigan, Minnesota, and Ohio, and that the Administrator does not have authority to promulgate the proposed FIP.

XXXIII. EPA Does Not Have the Authority to Mandate Emission Limits by Disapproving Adequate SIPs and Imposing its own FIP.

In *Train v. NRDC*, 412 U.S. 60, 79 (1975), the U.S. Supreme Court made clear that states have the authority under the Clean Air Act to develop the specific emission limitations that will ensure compliance with the NAAQS in the first instance. As the Court later stated in *Union Elec. Co. v. EPA*, "Congress plainly left with the States, so long as the national standards were met, the power to determine which sources would be burdened by regulation and to what extent." 427 U.S. 246, 269 (1976); *see also id.* at 267 (states have "virtually absolute power in allocating emission limitations so long as the national standards are met"). In light of the Supreme Court's holdings, the D.C. Circuit has held that the validity of EPA's own NAAQS program "depends in part on whether the program in effect constitutes an EPA-imposed control measure or emission limitation triggering the *Train-Virginia*[302] federalism bar: in other words, on whether the program constitutes an impermissible source-specific means rather than a permissible end goal." *Michigan v. EPA*, 213 F.3d 663, 687 (D.C. Cir. 2000) (internal alterations omitted).

In denying SIPs that adequately prevented significant contribution to nonattainment and interference with the NAAQS and supplanting these state-level approaches with a FIP that imposes EPA's preferred method of achieving the same goal, EPA's Proposed Rule supplants the states' role as primary decider of "which sources would be burdened by regulation and to what extent." This violates the federalism bar established in *Train* and *Virginia v. EPA*.

XXXIV. EPA Has No Authorization to Promulgate a FIP before Disapproving a SIP.

In the Proposed Rule, EPA has not even allowed time to finish deciding whether to disapprove the many ozone transport SIPs submitted for its review. Instead, EPA is accepting comments almost simultaneously both for disapproval of the SIPs and approval of EPA's proposed FIP. In fact, for some states EPA had not even proposed to disapprove the SIP submission before proposing the FIP. This is unlawful because the relevant statute only permits EPA to "promulgate a Federal implementation plan . . . after the Administrator . . . disapproves a State implementation plan submission."[303]

Contrary to EPA's assertion, no court decision has ever authorized EPA to propose a FIP before taking the predicate final action of disapproving a SIP in the states the FIP is proposed to

[302] *Virginia v. EPA*, 108 F. 3d 1397 (D.C. Cir. 1997).

[303] 42 U.S.C. 7410(c)(1)(B) (emphasis added).

cover.[304] In fact the D.C. Circuit expressly reserved judgement on this very issue the last time it was raised before the D.C. Circuit, dismissing it on administrative exhaustion grounds rather than approving EPA's approach. [305] Nor does the Supreme Court's opinion in *EME Homer* address this issue, as that opinion only determined that EPA need not provide States an additional opportunity to revise its SIP after disapproval of a SIP, not whether a FIP can be issued before disapproving a SIP in the first place.[306] If EPA does proceed with SIP denials, in the interest of cooperative federalism and in furtherance of the Clean Air Act itself, EPA should allow a reasonable time for States to address the grounds for denial before EPA promulgates a FIP.

XXXV. EPA Cannot Lawfully Issue FIP and Disapprove SIPs Based on Data Not Available at Time SIP Submissions Were Required.

As noted in the State of Arkansas' comments on EPA's proposed denial of Arkansas' proposed Good Neighbor SIP provisions for the 2015 Ozone NAAQS, EPA reevaluated the significance of contributions to downwind receptors based on data generated *after* the statutory deadline for EPA to act on approving or disapproving the Arkansas Transport SIP submission.[307] Had EPA reviewed the SIP in the timeframe required by federal law, the information available at the time—the same information that states used to inform their decisions—would not have supported a decision to disapprove the SIP for Arkansas, and subsequently would remove any statutory basis for EPA to promulgate a FIP for Arkansas. Although the D.C. Circuit has held that EPA has legal authority to propose a FIP at the same time it disapproves a SIP submission without giving the State an opportunity to fix the deficiency in the SIP submission, we are aware of no decision or statutory basis that would allow EPA to do so based on data that was unavailable to the State at the time that it made its SIP submission. On the contrary, "It is one thing to expect regulated parties to conform their conduct to an agency's interpretations once the agency announces them; it is quite another to require regulated parties to divine the agency's interpretations in advance or else be held liable when the agency announces its interpretations for the first time . . . and demands deference." [308] Accordingly, it was unreasonable and unlawful for EPA to disapprove the Arkansas submission based on data that the agency did not generate until after its statutory deadline to act on the Arkansas Transport SIP. Because EPA erred in denying the Arkansas Transport SIP, it was also not lawful for EPA to propose the Proposed Rule FIP to

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[304] Contra Proposed Rule at 20,057.

[305] *EME Homer City Generation, L.P. v. E.P.A.*, 795 F.3d 118, 132 (D.C. Cir. 2015) ("petitioners argue that EPA did not have authority to promulgate certain Transport Rule FIPs because those FIPs were signed by the EPA Administrator before EPA published its disapproval of the CAIR SIPs in the Federal Register. Petitioners did not raise this issue before the Agency during notice and comment, and EPA has not denied any petition for reconsideration raising this objection. We therefore may not entertain it now").

[306] *EPA v. EME Homer City Generation, LP*, 572 U.S. at 509 & n.14.

[307] See Comment submitted by Arkansas Department of Energy and Environment, Division of Environmental Quality, on EPA-R06-OAR-2021-0801-0001, at 3-4 (April 22, 2022).

[308] *Christopher v. SmithKline Beecham Corp.*, 567 U.S. 142, 158-59 (2012).

cover Arkansas, since EPA only has the authority to issue a FIP if a state failed to submit an approvable SIP or EPA properly disapproved it.[309]

XXXVI. Requirements For EPA SIP Review.

EPA states that "In order to replace the non-EGU portion of the FIP in a state, the state's SIP must provide adequate provisions to prohibit an equivalent or greater amount of NOx emissions that contribute significantly to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in any other state. The non-EGU requirements of the FIP would remain in place in each covered state until a state's SIP has been approved by the EPA to replace the FIP."[310] This is not reasonable or lawful for multiple reasons.

First, a state's ability to replace the FIP must be tied to whether it has addressed the underlying nonattainment/maintenance concerns by reducing significant contribution from sources in the state below the significance threshold, (as opposed to whether it prohibits equivalent emissions to the FIP). For instance, if Arkansas is able to show that it no longer has a significant contribution to the Brazoria receptor before the final FIP deadline for non-EGU emission reduction standards (whether due to White Bluff closure or otherwise), then there would no longer be any statutory basis for EPA to impose a Good Neighbor FIP on Arkansas.

Second, given that the limits imposed in the Proposed Rule are <u>not</u> the same as the statewide emission reductions that EPA modeled as being sufficient to resolve any significant contribution to nonattainment or interference with maintenance of the 2015 ozone NAAQS in downwind states, as explained in detail above, EPA cannot rationally judge a SIP based on whether it reduces emissions by a greater amount than the Proposed Rule's limits would. Rather, EPA's evaluation of any SIP could not require the SIP to result in more reductions than the amount of statewide emission reductions EPA actually modeled as resulting in attainment for linked receptors. i.e., the total amount specified at the Non-EGU Screening Assessment at Figure 2.

<u>CONCLUSION</u>

For the reasons set forth above U.S. Steel urges that EPA withdraw the Proposed Rule in favor of allowing states the opportunity to correct any concerns that EPA may have with their SIP submittals and in the alternative for EPA to correct the errors that have been identified with respect to its Proposed Rule. If EPA makes significant changes to the Proposed Rule, which are needed, then U. S. Steel requests the opportunity to be involved in a stakeholder process and to have adequate to review and comment on any changes.

U. S. Steel appreciates the opportunity to provide comments on the Proposed Rule. If you have any questions or should you need additional information, please do not hesitate to contact me at 479-200-9743 or kjones@uss.com.

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309 42 U.S.C. § 7410(c)(1).

310 Proposed Rule at 20,151.

Sincerely,

Kendra A. Jones, Esq.

Assistant General Counsel - Environmental
United States Steel Corporation

TECHNICAL MEMORANDUM

TO: Docket for Rulemaking, "Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards" (EPA-HQ-OAR-2021-0668)
DATE: February 28, 2022
SUBJECT: Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026

Note: EPA originally posted this document on March 11, 2022. This document, posted on March 29, 2022, corrects inadvertent errors referencing a filename on page 9 and in Table 5 on page 16.

I. Introduction

The EPA developed an analytical framework to facilitate decisions about industries, emissions unit types, and cost thresholds for including emissions units in the non-electric generating unit "sector" (non-EGUs) in a federal implementation plan (FIP) proposal for the 2015 ozone national ambient air quality standards (NAAQS) transport obligations. Using this analytical framework, we prepared a screening assessment for the year 2026.

This memorandum presents the analytical framework and summarizes the screening assessment the EPA prepared to identify industries and emissions unit types to include in proposed rules to obtain NOx emissions reductions from non-EGUs. Sections VII.A.2. and VII.C. of the proposal preamble include discussions of the non-EGU NOx emissions limits, compliance timing, and other related-rule requirements for the industries and emissions unit types identified through the screening assessment.

The remainder of this memorandum includes the following sections:

II. Background on Analytical Framework
III. The Analytical Framework
  - Step 1 -- Identifying Potentially Impactful Industries in 2023
  - Step 2a -- Identifying a Cost Threshold to Evaluate Emissions Reductions in Potentially Impactful Industries for 2023
  - Step 2b -- Assessing Non-EGU Emission Reduction Potential and Estimated Air Quality Impacts in Potentially Impactful Industries in 2023
  - Step 2c – Refining Tier 2 by Identifying Potentially Impactful Boilers in 2023

IV. Modifying the Analytical Framework for the Screening Assessment for 2026
V. Screening Assessment Results for 2026 -- Estimated Total Emissions Reductions, Air Quality Improvements, and Annual Total Costs for Emissions Units in Tier 1 Industries and Impactful Boilers in Tier 2 Industries
VI. Request for Comment and Additional Information

II. Background on Analytical Framework

The number of different industries and emissions unit categories and types, as well as the total number of emissions units that comprise the non-EGU "sector"[1] makes it challenging to define a single method to identify impactful emissions reductions. We incorporated air quality information as a first step in the analytical framework to help determine potentially impactful industries to focus on for further assessing emission reduction potential, air quality improvements, and costs. Given the lengthy decision-making and analysis schedules for the FIP

[1] The non-EGU "sector" includes non-electric generating emissions units in various manufacturing industries and does not include municipal waste combustors (MWC), cogeneration units, or <25 MW EGUs. For a discussion of MWCs, cogeneration units, and EGUs <25 MW, see Section VI.B.3. of the proposed rule preamble.

proposal, we developed the analytical framework using inputs from the air quality modeling for the Revised CSAPR Update (RCU) for 2023[2], as well as the projected 2023 annual emissions inventory from the 2016v2 emissions platform that was used for the air quality modeling for the proposed rule.

Using the RCU modeling for 2023, we identified upwind states linked to downwind nonattainment or maintenance receptors using the 1% of the NAAQS threshold criterion, which is 0.7 ppb (1% of a 70 ppb NAAQS). In 2023 there were 27 linked states for the 2015 NAAQS: AL, AR, CA, DE, IA, IL, IN, KY, LA, MD, MI, MN, MO, MS, NJ, NY, NV, OH, OK, PA, TN, TX, UT, VA, WI, WV, and WY.

To analyze non-EGU emissions units, we aggregated the underlying projected 2023 emissions inventory data into industries defined by 4-digit NAICS.[3] Then for the linked states, we followed the 2-step process below:

1. **Step 1** -- We identified industries whose potentially controllable emissions are estimated, by applying the analytical framework, to have the greatest ppb impact on downwind air quality, [4] and
2. **Step 2** – We determined which of the most impactful industries and emissions units had the most emissions reductions that would make meaningful air quality improvements at the downwind receptors at a marginal cost threshold we determined using underlying control device efficiency and cost information.

Additional details on these steps are presented in the Section III below.

Finally, the EPA concluded, based on the most recent information available from the CSAPR Update Non-EGU TSD,[5] that controls on all of the non-EGU emissions units cannot be installed by the 2023 ozone season.[6] As such, we modified the analytical framework slightly and applied it for a screening assessment estimating potential emissions reductions, air quality improvements, and costs for the year 2026.

III. The Analytical Framework

Step 1 - Identifying Potentially Impactful Industries in 2023

The analytical framework starts with identifying industries whose potentially controllable emissions may contribute to downwind receptors. To identify industries that have large, meaningful air quality impacts from potentially controllable emissions, we estimated air quality contribution by 4-digit NAICS-based industry for 2023. To estimate the contributions by 4-digit NAICS at each downwind receptor, we used the 2023 state-receptor specific RCU ppb/ton values and the RCU calibration factors used in the air quality assessment tool (AQAT) for control analyses in 2023.[7]

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[2] We used the RCU air quality modeling for this screening assessment because the air quality modeling for the proposed rule was not completed in time to support this assessment.

[3] North American Industry Classification System (https://www.census.gov/naics/).

[4] To identify industries, we reviewed emissions units with >= 100tpy emissions units in the 2023 inventory in those industries in the upwind states.

[5] Final Technical Support Document (TSD) for the Final Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Assessment of Non-EGU NO_X Emissions Controls, Cost of Controls, and Time for Compliance Final TSD ("CSAPR Update Non-EGU TSD"), August 2016, available at *https://www.epa.gov/csapr/assessment-non-egu-NOx-emission-controls-cost-controls-and-time-compliance-final-tsd*.

[6] Note that information on control installation timing as detailed in the 2016 CSAPR Update Non-EGU TSD is not complete or sufficient to serve as a foundation for timing estimates for this proposed FIP.

[7] The calibration factors are receptor-specific factors. For the RCU, the calibration factors were generated using 2016 base case and 2023 base case air quality model runs. These receptor-level ppb/ton factors are discussed in the Ozone Transport

We focused on assessing emissions units that emit >100 tpy of NOx.[8] By limiting the focus to potentially controllable emissions, well-controlled sources that still emit > 100 tpy are excluded from consideration. Instead, the focus is on uncontrolled sources or sources that could be better controlled at a reasonable cost. As a result, reductions from any industry identified by this process are more likely to be achievable and to lead to air quality improvements.

Based on the industry contribution data, we prepared a summary of the estimated total, maximum, and average contributions from each industry and the number of receptors with contributions >= 0.01 ppb from each industry. We evaluated this information to identify breakpoints in the data, as described in detail in Appendix A. These breakpoints were then used to identify the most impactful industries to focus on for the next steps in the analysis.[9]

A review of the contribution data indicated that we should focus the assessment of NOx reduction potential and cost primarily on four industries. These industries each (1) have a maximum contribution to any one receptor of >0.10 ppb and (2) contribute >= 0.01 ppb to at least 10 receptors. We refer to these four industries identified below as comprising **"Tier 1"**.

- Pipeline Transportation of Natural Gas
- Cement and Concrete Product Manufacturing
- Iron and Steel Mills and Ferroalloy Manufacturing
- Glass and Glass Product Manufacturing

In addition, the contribution data suggests that we should include five additional industries as a second tier in the assessment. These industries each either have (1) a maximum contribution to any one receptor >=0.10 ppb but contribute >=0.01 ppb to fewer than 10 receptors, or (2) a maximum contribution <0.10 ppb but contribute >=0.01 ppb to at least 10 receptors. We refer to these five industries identified below as comprising **"Tier 2"**.

- Basic Chemical Manufacturing
- Petroleum and Coal Products Manufacturing
- Metal Ore Mining
- Lime and Gypsum Product Manufacturing
- Pulp, Paper, and Paperboard Mills

Policy Analysis Final Rule TSD found here: https://www.epa.gov/sites/default/files/2021-03/documents/ozone_transport_policy_analysis_final_rule_tsd_0.pdf.

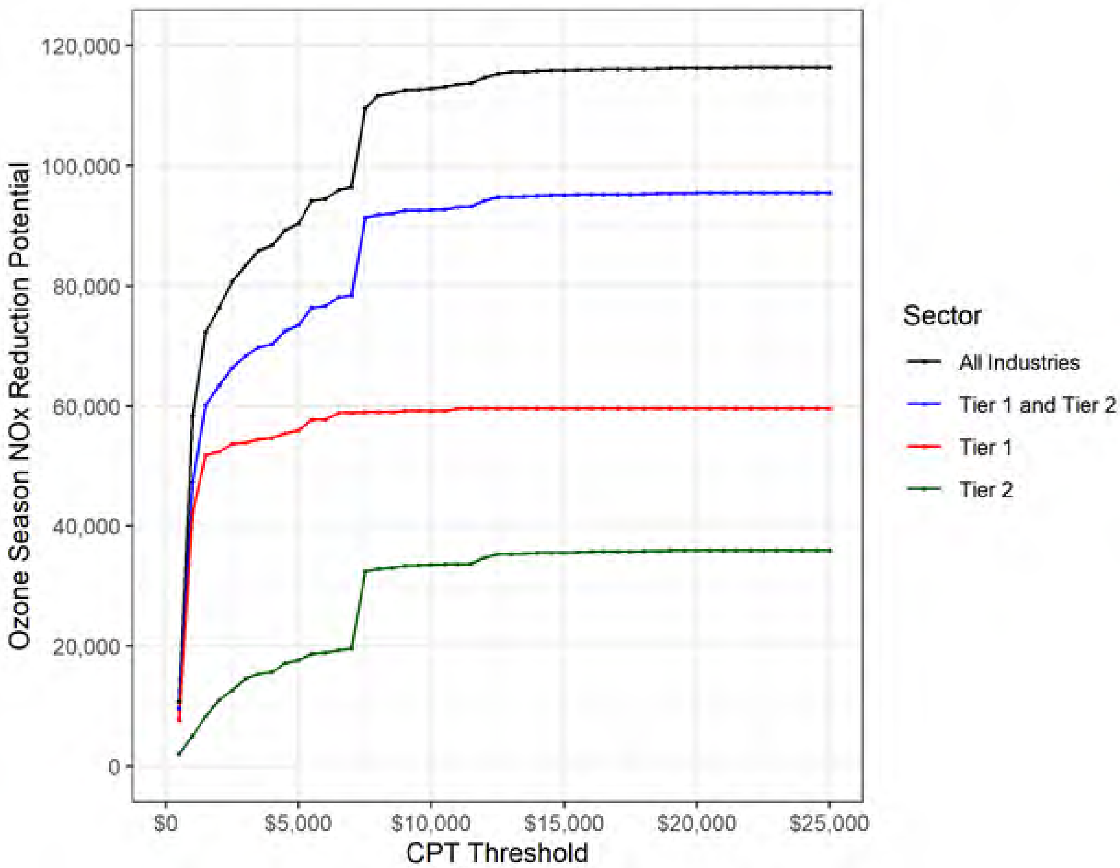
[8] In the non-EGU emission reduction assessment prepared for the Revised Cross State Air Pollution Rule Update (https://www.regulations.gov/document/EPA-HQ-OAR-2020-0272-0014), we reviewed emissions units with >150 tpy of NOx emissions. In this screening assessment, we broadened the scope to include emissions units with >=100 tpy of NOx emissions. We believe that emissions units that are smaller may already be controlled and reductions from these smaller units are likely to be more costly.

[9] The air quality contribution data and the R code that processed these data are available upon request.

Step 2a - Identifying a Cost Threshold to Evaluate Emissions Reductions in Potentially Impactful Industries for 2023

To identify an annual cost threshold for evaluating potential emissions reductions in the Tier 1 and Tier 2 industries, the EPA used the Control Strategy Tool (CoST)[10], the Control Measures Database (CMDB)[11], and the projected 2023 emissions inventory to prepare a listing of potential control measures, and costs, applied to non-EGU emissions units in the projected 2023 emissions inventory. Using this data, we plotted curves for Tier 1 industries, Tier 2 industries, Tier 1 and 2 industries, and all industries at $500 per ton increments. Figure 1 indicates there is a "knee in the curve" at approximately $7,500 per ton.[12] We used this marginal cost threshold to further assess estimated emissions reductions, air quality improvements, and costs from the potentially impactful industries. Note that controls and related emissions reductions are available at several estimated cost levels up to the $7,500 per ton threshold. The costs do not include monitoring, recordkeeping, reporting, or testing costs.

Figure 1. Ozone Season NOx Reductions and Costs per Ton (CPT) for Tier 1, Tier 2 Industries, and Other Industries



[10] Further information on CoST can be found at the following link: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.

[11] The CMDB is available at the following link: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.

[12] The CoST run results, the CMDB, and the R code that generated the curves are available upon request.

Step 2b - Assessing Non-EGU Emission Reduction Potential and Estimated Air Quality Impacts in Potentially Impactful Industries in 2023

Next, using the marginal cost threshold of $7,500 per ton, to estimate emissions reductions and costs the EPA processed the CoST run using the maximum emission reduction algorithm[13,14] with known controls.[15] We identified controls for non-EGU emissions units in the Tier 1 and Tier 2 industries that cost up to $7,500 per ton. Note that $7,500 per ton represents a marginal cost, and controls and related emissions reductions are available at several estimated costs up to the $7,500 per ton threshold. The costs do not include monitoring, recordkeeping, reporting, or testing costs.

We then calculated air quality impacts associated with the estimated reductions for the 27 linked states in 2023 following the steps below.

1. We binned the estimated reductions by 4-digit NAICS code into the Tier 1 and Tier 2 industries.
2. We used the 2023 state-receptor specific RCU ppb/ton values and the RCU calibration factors used in the AQAT for control analyses in 2023. We multiplied the estimated non-EGU reductions by the ppb/ton values and by the receptor-specific calibration factor to estimate the ppb impacts from these emissions reductions.[16]

Note that we did not include the impact of reductions in the "home state" even if the "home state" was linked to receptor(s) in another state. That is, we only looked at the impact of NOx emissions reductions from upwind states. Furthermore, for each receptor we included impacts from states that are upwind to any receptor, not just those states that are upwind to that particular receptor.

Step 2c – Refining Tier 2 by Identifying Potentially Impactful Boilers in 2023

In 2023 because boilers represent the majority emissions unit in the Tier 2 industries for which there were controls that cost up to $7,500 per ton (see Table 1 below), we targeted emissions reductions and air quality improvements in Tier 2 industries by identifying potentially impactful industrial, commercial, and institutional (ICI) boilers.

[13] The maximum emission reduction algorithm assigns to each source the single measure (if a measure is available for the source) that provides the maximum reduction to the target pollutant. For more information, see the CoST User's Guide available at the following link: https://www.cmascenter.org/cost/documentation/3.7/CoST%20User's%20Guide/.
[14] The maximum emission reduction CoST run results and CMDB are available upon request.
[15] *Known controls* are well-demonstrated control devices and methods that are currently used in practice in many industries. *Known controls* do not include cutting edge or emerging pollution control technologies.
[16] The 2023 state-receptor specific RCU ppb/ton values, the RCU calibration factors used in AQAT for control analyses in 2023, the R code that processed the CoST run results using the maximum emission reduction algorithm, and the summaries of the air quality improvements are available upon request.

Table 1. Number of Emissions Unit Types in Tier 2 Industries

	Number of Emissions Units by Type		
Tier 2 Industries	**Boiler**	**Internal Combustion Engine**	**Industrial Processes**
Metal Ore Mining	--	1	15
Pulp, Paper, and Paperboard Mills	49	1	--
Petroleum and Coal Products Manufacturing	37	4	48
Basic Chemical Manufacturing	46	8	13
Lime and Gypsum Product Manufacturing	--	--	1
Totals	**132**	**14**	**77**

To identify potentially impactful boilers, using the projected 2023 emissions inventory in the linked upwind states we identified a universe of boilers with >100 tpy NOx emissions that had any contributions at downwind receptors.[17,18] We refined the universe of boilers to a subset of impactful boilers by sequentially applying the three criteria below to each boiler. This approach is similar to the overall analytical framework and was tailored for application to individual boilers.[19,20]

- Criterion 1 -- Estimated maximum air quality contribution at an individual receptor of >=0.0025 ppb ***or*** estimated total contribution across downwind receptors of >=0.01 ppb***.***
- Criterion 2 -- Controls that cost up to $7,500 per ton.
- Criterion 3 -- Estimated maximum air quality improvement at an individual receptor of >=0.001 ppb.

IV. Modifying the Analytical Framework for the Screening Assessment for 2026

EPA concluded, based on the most recent information available from the CSAPR Update Non-EGU TSD, that controls on all of the non-EGU emissions units cannot be installed by the 2023 ozone season. As such, we prepared a screening assessment for the year 2026 by generally applying the analytical framework detailed above. Specifically, we

- Retained the impactful industries identified in Tier 1 and Tier 2, the $7,500 cost per ton threshold, and the methodology for identifying impactful boilers,
- Modified the framework to address challenges associated with using the projected 2023 emissions inventory by using the 2019 emissions inventory, and
- Updated the air quality modeling data by using data for 2026.

Using the projected 2023 emissions inventory introduced challenges associated with the application of new source performance standards (NSPS).[21] Some of the projected emissions inventory records reflected percent

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[17] We used the 2023fj non-EGU point source inventory files from the 2016v2 emissions platform.

[18] MD, MO, NV, and WY did not have boilers with >100 tpy NOx emissions.

[19] For the impactful boiler assessment, the estimated air quality contributions and improvements were not based on modeling of individual emissions units or emissions source sectors. The air quality estimates were derived by using the 2023 state/receptor specific RCU ppb/ton values and the RCU calibration factors used in AQAT. The results are intended to provide a general indication of the relative impact across sources.

[20] For the impactful boiler assessment, the 2023 state-receptor specific RCU ppb/ton values, the RCU calibration factors used in the AQAT for ozone for control analyses in 2023, and the R code that processed the CoST run results are available upon request.

[21] Using the projected inventory also introduced challenges associated with the growth of emissions at sources over time. EPA determined that the 2019 inventory was appropriate because it provided a more accurate prediction of potential near-

reductions associated with the application of current NSPS (e.g., Reciprocating Internal Combustion Engine, Natural Gas Turbines, Process Heaters NSPS). Applying NSPSs during the emissions projections process includes estimating the number of modifications/replacements that would trigger NSPS requirements. None of the existing sources, as they currently exist, would install a control because of a NSPS. But some of those sources might modify and become subject to the NSPS. Because we do not know which sources might become subject to an NSPS by modifying, across-the-board percent reductions from unknown control measures are applied to all of the sources.[22] As a result, CoST replaced some of the unknown control measures with a control measure that it concluded was more efficient. However, we do not know if a control would be applied to a particular source in response to the NSPS rules and if so, what that control would be. Therefore, we do not know if CoST is correctly replacing those unknown control measures. To address this challenge, we used a current, not projected, emissions inventory along with the latest air quality modeling information for 2026. Specifically, we used the 2019 inventory for information on emissions, emissions units, and estimated emissions reductions in concert with the emissions sector-specific (non-EGU-specific) ppb/ton factors for 2026 and 2026 AQAT calibration factors to estimate the impacts on future air quality from reductions at emissions units as those units currently exist.[23]

V. Screening Assessment Results for 2026 -- Estimated Total Emissions Reductions, Air Quality Improvements, and Annual Total Costs for Emissions Units in Tier 1 Industries and Impactful Boilers in Tier 2 Industries

This screening assessment is not intended to be, nor take the place of, a unit-specific detailed engineering analysis that fully evaluates the feasibility of retrofits for the emissions units, potential controls, and related costs. We used CoST to identify emissions units, emissions reductions, and costs to include in a proposed FIP; however, CoST was designed to be used for illustrative control strategy analyses (e.g., NAAQS regulatory impact analyses) and not for unit-specific, detailed engineering analyses. The estimates from CoST identify proxies for (1) non-EGU emissions units that have emission reduction potential, (2) potential controls for and emissions reductions from these emissions units, and (3) control costs from the potential controls on these emissions units.

See Sections VII.A.2. and VII.C. of the proposal preamble for discussions of the NOx emissions limits, compliance timing, and other related rule requirements for the industries and emissions unit types identified through this screening assessment.

To prepare the screening assessment for 2026, we applied the analytical framework detailed in the sections above with the modifications discussed in the previous section. The assessment includes emissions units from the Tier 1 industries and impactful boilers from the Tier 2 industries. Using the latest air quality modeling for 2026, we identified upwind states linked to downwind nonattainment or maintenance receptors using the 1% of the NAAQS threshold criterion, or 0.7 ppb. In 2026 there are 23 linked states for the 2015 NAAQS: AR, CA, IL, IN, KY, LA, MD, MI, MN, MO, MS, NJ, NY, NV, OH, OK, PA, TX, UT, VA, WI, WV, and WY.

We re-ran CoST with known controls, the CMDB, and the 2019 emissions inventory. We specified CoST to allow replacing an existing control if a replacement control is estimated to be >10 percent more effective than the

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term emissions reductions. For additional discussion of the 2019 inventory, please see the *2019 National Emissions Inventory Technical Support Document: Point Data Category* available in the docket. In switching to the 2019 inventory, however, we did not account for any growth or decrease in emissions that might occur at individual units. Because the controls applied by CoST have efficiencies, or percent reductions, this means we could be over- or under-estimating the emission reductions and their ppb impacts.

[22] For additional information on the 2016v2 inventory and the projected 2023 emissions inventory, please see the September 2021 *Technical Support Document Preparation of Emissions Inventories for 2016v2 North American Emissions Modeling Platform* in the docket or available at the following link: https://www.epa.gov/system/files/documents/2021-09/2016v2_emismod_tsd_september2021.pdf.

[23] For this proposed FIP, the EPA used the ozone AQAT, which is described in detail in *Ozone Policy Analysis Proposed Rule TSD* in the docket. The receptor-state specific calibration factors for 2026 were derived using the following air quality modeling runs: 2026 base case and 2026 control case with 30 percent across-the-board NOx emissions cuts.

existing control. We did not replace an existing control if the 2019 emissions inventory indicated the presence of that control, even if the CMDB reflects a greater control efficiency for that control. Also, we removed six facilities from consideration because they are subject to an existing consent decree, are shut down, or will shut down by 2026. See Appendix B for a summary of the facilities removed.

For the emissions units in the Tier 1 industries and the impactful boilers in the Tier 2 industries, the estimated emissions reductions, air quality improvements, and costs are summarized below and in Tables 2 through 5 that follow. The cost estimates do not include monitoring, recordkeeping, reporting, or testing costs.[24] As shown in Table 2, the total estimated ozone season emissions reductions are 47,186 tons, the estimated total ppb improvement across all downwind receptors is 5.16 ppb, and the estimated total cost is $410.8 million annually. The estimated ozone season reductions, total ppb improvements, and total cost are representative of single year impacts and not cumulative impacts.

Table 3 presents estimated ppb improvements at receptors grouped by region. For the coastal Connecticut/New York City nonattainment area receptors, total ppb improvements from Tier 1 and Tier 2 range from 0.247 to 0.356 ppb; for the receptors near Chicago, total ppb improvements range from 0.261 to 0.375 ppb; for the receptors along the western shoreline of Lake Michigan in Wisconsin, total ppb improvements range from 0.360 to 0.443 ppb; for the Houston receptors, total ppb improvements range from 0.284 to 0.472 ppb; and for the western receptors, ppb improvements range from <0.001 to 0.056 ppb. There are far fewer emissions reductions from western states because there are far fewer states and impacted emissions units in the west, and the resulting air quality improvements are noticeably lower.

For Tier 1 industries and the impactful boilers in the Tier 2 industries, Table 4 provides by state and by industry estimated emissions reductions and costs; Table 4a provides by state, estimated emissions reductions and costs. New Jersey and Nevada are not included in these tables because they did not have any estimated non-EGU reductions from the Tier 1 industries and boilers in Tier 2 industries that cost up to $7,500 per ton. In addition, Figure 2 shows the geographical distribution of ozone season reductions.

Table 5 provides by industry and east/west, the number and type of emissions units, total estimated emissions reductions, total ppb improvements, and costs. There are 489 emissions units contributing to the total estimated reductions of 47,186 ozone season tons and total estimated ppb improvements of 5.16 ppb.[25]

Table 6 includes by industry, the emissions source group, control technology, number of emissions units, ozone season emissions reductions, and annual total cost for the emissions units in the screening assessment. Lastly, Tables 7, 8, and 9 provide summaries of estimated ozone season emissions reductions, annual total cost, and average cost per ton by the control technologies CoST applied (i) across all non-EGU emissions units, (ii) across non-EGU emissions units grouped by the Tier 1 industries and impactful boilers in Tier 2 industries, and (iii) across non-EGU emissions units grouped by the seven individual Tier 1 and 2 industries.

[24] EPA submitted an information collection request (ICR) to OMB associated with the proposed monitoring, calibrating, recordkeeping, reporting and testing activities required for non-EGU emissions units -- *ICR for the Proposed Rule, Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Primary Ozone National Ambient Air Quality Standard: Transport Obligations for non-Electric Generating Units*, EPA ICR No. 2705.01. The ICR is summarized in Section XI.B.2 of the proposed rule preamble. The ICR includes estimated monitoring, recordkeeping, reporting, and testing costs of approximately $11.45 million per year for the first three years. These costs are not reflected in the cost estimates presented in Tables 2 through 9.

[25] While the number of units listed in Table 5 sums to 491, the emissions inventory records for two of the units in Tier 1 industries include SCCs for both boilers and industrial processes. As a result, those units appear twice in the counts.

For the Excel workbooks with Tables 2 through 9, see *Transport Proposal – NonEGU Results – 03-16-2022.xlsx* and *Non-EGU Analysis Controls – 11-15-2021.xlsx* in the docket.[26]

[26] The R code that processed the CoST run results, the sector-specific (non-EGU-specific) ppb/ton values, and the 2026 AQAT calibration factors used to prepare these tables are available upon request.

All costs are in 2016$ and do not include monitoring, recordkeeping, reporting, or testing costs.

Table 2. Estimated Emissions Reductions (ozone season tons), Maximum PPB Improvements, and Costs

Option	**Ozone Season Emissions Reductions (East/West)**	**Total PPB Improvement Across All Downwind Receptors**	**Max PPB Improvement Across All Downwind Receptors**	**Annual Total Cost (million $) (Avg Annual Cost per Ton)**	**Industries (# of emissions units > 100 tpy in identified industries)**
Tier 1 Industries with Known Controls that Cost up to $7,500/ton	41,153 (37,972/3,181)	4.352	0.392	$356.6 ($3,610)	Cement and Concrete Product Manufacturing (47), Glass and Glass Product Manufacturing (44), Iron and Steel Mills and Ferroalloy Manufacturing (39), Pipeline Transportation of Natural Gas (307)
Tier 2 Industry Boilers with Known Controls that Cost up to $7,500/ton	6,033 (5,965/68)	0.809	0.169	$54.2 ($3,744)	Basic Chemical Manufacturing (17), Petroleum and Coal Products Manufacturing (10), Pulp, Paper, and Paperboard Mills (25)

The estimated ozone season reductions, total ppb improvements, and total cost are representative of single year impacts and not cumulative impacts.

Table 3. Estimated PPB Improvements at Receptors Grouped by Region*

Receptor ID	State	Receptor Name	Average/Max PPB Improvement Needed to Attain	Home State PPB Contribution	Tier 1	Tier 2	Total
90010017	CT	Greenwich	0.6/1.3	9.3	0.231	0.016	0.247
90013007	CT	Stratford	1.9/2.8	4.1	0.332	0.024	0.356
90019003	CT	Westport	3.7/3.9	2.9	0.314	0.022	0.336
90099002	CT	Madison	-/1.5	3.9	0.323	0.023	0.346
170310001	IL	Chicago/Alsip	-/1.6	19.4	0.196	0.065	0.261
170310032	IL	Chicago/South	-/0.8	16.6	0.299	0.076	0.375
170310076	IL	Chicago/ComEd	-/0.4	18.7	0.229	0.060	0.289
170314201	IL	Chicago/Northbrook	-/1.5	21.4	0.262	0.069	0.332
170317002	IL	Chicago/Evanston	-/1.1	18.9	0.307	0.049	0.356
550590019	WI	Kenosha/Water Tower	0.8/1.7	5.8	0.325	0.035	0.360
550590025	WI	Kenosha/Chiwaukee	-/0.2	2.6	0.392	0.051	0.443
551010020	WI	Racine/Racine	-/1.2	10.8	0.353	0.044	0.397
480391004	TX	Houston/Brazoria	-/0.3	29.3	0.302	0.169	0.472
482010024	TX	Houston/Aldine	3.3/4.8	29.7	0.186	0.098	0.284
40278011	AZ	Yuma	-/0.9	2.8	0.027	0.001	0.028
60070007	CA	Butte	-/-0.8	23.5	0.000	0.000	0.000
60170010	CA	El Dorado #1	4.1/6.5	26.7	0.000	0.000	0.000
60170020	CA	El Dorado #2	2.3/4.1	28.7	0.000	0.000	0.000
60190007	CA	Fresno #1	8.6/10.4	29.1	0.001	0.000	0.001
60190011	CA	Fresno #2	11/11.9	31.1	0.002	0.000	0.002
60195001	CA	Fresno #3	11.8/14.5	30.2	0.002	0.000	0.002
60570005	CA	Nevada	6.3/9.6	25.4	0.000	0.000	0.000
60610003	CA	Placer #1	5/7.7	29.8	0.000	0.000	0.000
60610004	CA	Placer #2	0/5.1	24	0.000	0.000	0.000
60670012	CA	Sacramento	2.7/3.4	30.8	0.000	0.000	0.000
60990005	CA	Stanislaus	3.8/4.7	29.2	0.001	0.000	0.001
80350004	CO	Denver/Chatfield	-/0.2	15.6	0.055	0.001	0.056
80590006	CO	Rocky Flats	0.8/1.4	17.3	0.042	0.000	0.042
80590011	CO	Denver/NREL	1.7/2.4	17.6	0.044	0.001	0.044
490110004	UT	SLC/Bountiful	0.8/3	8	0.037	0.002	0.038
490353006	UT	SLC/Hawthorne	1.6/3.2	8.3	0.036	0.002	0.038
490353013	UT	SLC/Herriman	2.6/3.1	8.9	0.018	0.001	0.019
490570002	UT	SLC/Ogden	-/0.8	6.1	0.034	0.001	0.035

**Home state emission reductions are not assumed in this analysis.*

Table 4. For Tier 1 Industries and Impactful Boilers in Tier 2 Industries, By State And By Industry, Estimated Emissions Reductions (ozone season tons*) and Costs

		Tier 1		Tier 2	
State	Industry	Ozone Season Emissions Reductions	Annual Total Cost (million $) (Avg Annual Cost per Ton)	Ozone Season Emissions Reductions	Annual Total Cost (million $) (Avg Annual Cost per Ton)
AR	Basic Chemical Manufacturing	-	-	87	$1.1 ($5,113)
AR	Glass and Glass Product Manufacturing	47	$0.2 ($2,046)	-	-
AR	Iron and Steel Mills and Ferroalloy Manufacturing	6	$0.0 ($631)	-	-
AR	Pipeline Transportation of Natural Gas	868	$10.1 ($4,852)	-	-
AR	Pulp, Paper, and Paperboard Mills	-	-	646	$6.1 ($3,967)
CA	Cement and Concrete Product Manufacturing	1,162	$3.6 ($1,279)	-	-
CA	Glass and Glass Product Manufacturing	299	$0.9 ($1,293)	-	-
CA	Petroleum and Coal Products Manufacturing	-	-	68	$0.4 ($2,349)
CA	Pipeline Transportation of Natural Gas	137	$1.5 ($4,718)	-	-
IL	Cement and Concrete Product Manufacturing	234	$0.7 ($1,279)	-	-
IL	Glass and Glass Product Manufacturing	901	$2.6 ($1,180)	-	-
IL	Pipeline Transportation of Natural Gas	1,316	$13.7 ($4,348)	-	-
IN	Cement and Concrete Product Manufacturing	468	$1.4 ($1,279)	-	-
IN	Glass and Glass Product Manufacturing	338	$1.7 ($2,046)	-	-
IN	Iron and Steel Mills and Ferroalloy Manufacturing	1,829	$16.0 ($3,653)	-	-
IN	Petroleum and Coal Products Manufacturing	-	-	388	$2.8 ($2,989)
IN	Pipeline Transportation of Natural Gas	152	$2.0 ($5,457)	-	-
KY	Pipeline Transportation of Natural Gas	2,291	$28.7 ($5,213)	-	-
LA	Basic Chemical Manufacturing	-	-	1,611	$15.2 ($3,939)
LA	Glass and Glass Product Manufacturing	206	$1.9 ($3,770)	-	-
LA	Petroleum and Coal Products Manufacturing	-	-	477	$4.0 ($3,498)
LA	Pipeline Transportation of Natural Gas	3,915	$44.3 ($4,720)	-	-
LA	Pulp, Paper, and Paperboard Mills	-	-	561	$5.2 ($3,830)
MD	Pipeline Transportation of Natural Gas	45	$0.3 ($3,042)	-	-
MI	Cement and Concrete Product Manufacturing	371	$1.1 ($1,279)	-	-
MI	Glass and Glass Product Manufacturing	50	$0.3 ($2,661)	-	-
MI	Iron and Steel Mills and Ferroalloy Manufacturing	38	$0.4 ($4,194)	-	-
MI	Pipeline Transportation of Natural Gas	2,272	$25.9 ($4,747)	-	-
MN	Glass and Glass Product Manufacturing	115	$0.6 ($2,288)	-	-
MN	Pipeline Transportation of Natural Gas	558	$7.3 ($5,452)	-	-
MO	Cement and Concrete Product Manufacturing	1,296	$4.0 ($1,279)	-	-
MO	Glass and Glass Product Manufacturing	227	$1.1 ($1,992)	-	-
MO	Pipeline Transportation of Natural Gas	1,581	$20.2 ($5,338)	-	-
MS	Pipeline Transportation of Natural Gas	1,577	$19.0 ($5,009)	-	-
MS	Pulp, Paper, and Paperboard Mills	-	-	184	$1.4 ($3,243)
NY	Cement and Concrete Product Manufacturing	142	$0.4 ($1,279)	-	-
NY	Glass and Glass Product Manufacturing	141	$0.5 ($1,572)	-	-
NY	Pipeline Transportation of Natural Gas	106	$1.2 ($4,697)	-	-
NY	Pulp, Paper, and Paperboard Mills	-	-	111	$1.2 ($4,486)

OH	Cement and Concrete Product Manufacturing	116	$0.4 ($1,279)	-	-
OH	Glass and Glass Product Manufacturing	451	$2.2 ($1,998)	-	-
OH	Iron and Steel Mills and Ferroalloy Manufacturing	847	$7.6 ($3,763)	-	-
OH	Pipeline Transportation of Natural Gas	1,198	$14.6 ($5,062)	-	-
OH	Pulp, Paper, and Paperboard Mills	-	-	179	$2.3 ($5,303)
OK	Cement and Concrete Product Manufacturing	586	$1.8 ($1,279)	-	-
OK	Glass and Glass Product Manufacturing	190	$1.2 ($2,550)	-	-
OK	Pipeline Transportation of Natural Gas	2,799	$34.1 ($5,083)	-	-
PA	Cement and Concrete Product Manufacturing	888	$2.8 ($1,336)	-	-
PA	Glass and Glass Product Manufacturing	1,379	$3.8 ($1,133)	-	-
PA	Iron and Steel Mills and Ferroalloy Manufacturing	438	$6.1 ($5,823)	-	-
PA	Petroleum and Coal Products Manufacturing	-	-	98	$0.6 ($2,349)
PA	Pipeline Transportation of Natural Gas	427	$4.1 ($3,994)	-	-
PA	Pulp, Paper, and Paperboard Mills	-	-	54	$0.9 ($7,019)
TX	Cement and Concrete Product Manufacturing	1,234	$7.8 ($2,624)	-	-
TX	Glass and Glass Product Manufacturing	1,470	$3.9 ($1,109)	-	-
TX	Pipeline Transportation of Natural Gas	1,736	$20.7 ($4,966)	-	-
UT	Cement and Concrete Product Manufacturing	520	$1.6 ($1,279)	-	-
UT	Pipeline Transportation of Natural Gas	237	$2.7 ($4,718)	-	-
VA	Cement and Concrete Product Manufacturing	398	$1.2 ($1,279)	-	-
VA	Glass and Glass Product Manufacturing	174	$0.9 ($2,154)	-	-
VA	Iron and Steel Mills and Ferroalloy Manufacturing	92	$1.0 ($4,357)	-	-
VA	Pipeline Transportation of Natural Gas	801	$10.5 ($5,457)	-	-
VA	Pulp, Paper, and Paperboard Mills	-	-	98	$1.4 ($5,903)
WI	Glass and Glass Product Manufacturing	677	$2.5 ($1,517)	-	-
WI	Pulp, Paper, and Paperboard Mills	-	-	1,472	$11.7 ($3,307)
WV	Cement and Concrete Product Manufacturing	230	$0.7 ($1,279)	-	-
WV	Pipeline Transportation of Natural Gas	751	$6.5 ($3,612)	-	-
WY	Cement and Concrete Product Manufacturing	446	$1.4 ($1,279)	-	-
WY	Pipeline Transportation of Natural Gas	380	$4.9 ($5,349)	-	-
	Grand Total	**41,153**	**$356.6 ($3,610)**	**6,033**	**$54.2 ($3,744)**

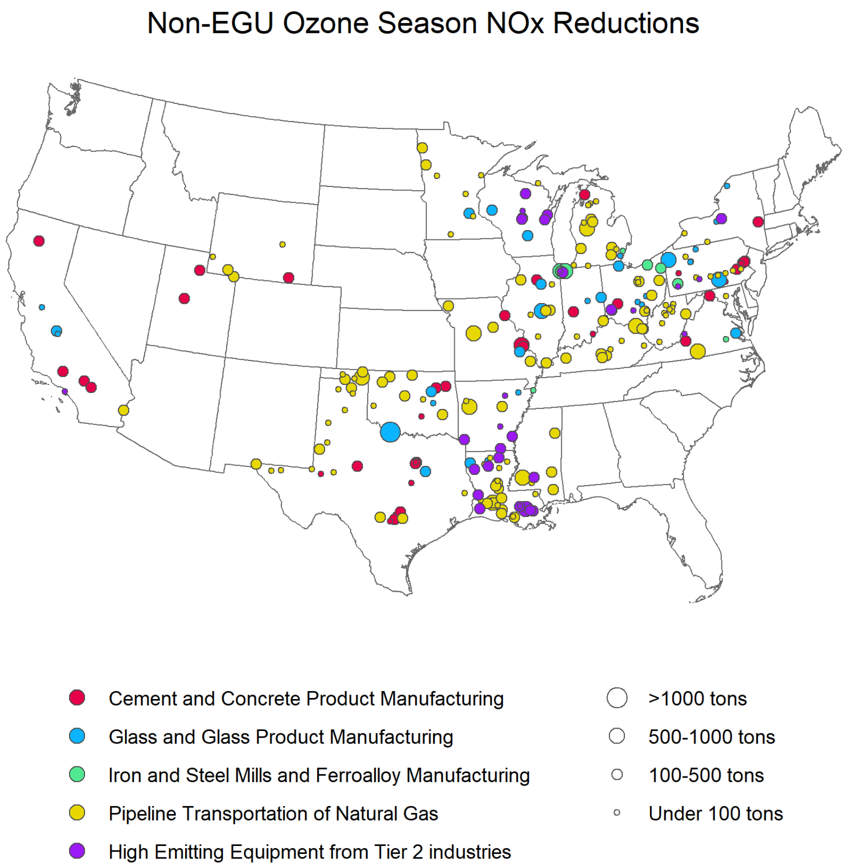
*Ozone season tons are calculated as tpy from the NEI multiplied by 5/12.

Note that New Jersey and Nevada did not have any estimated non-EGU reductions that cost up to $7,500 per ton from the Tier 1 industries and boilers in Tier 2 industries.

Table 4a. For Tier 1 Industries and Impactful Boilers in Tier 2 Industries, By State, Estimated Emissions Reductions (ozone season tons) and Costs

	Tier 1		Tier 2	
State	Ozone Season Emissions Reductions	Annual Total Cost (million $) (Avg Annual Cost per Ton)	Ozone Season Emissions Reductions	Annual Total Cost (million $) (Avg Annual Cost per Ton)
AR	922	$10.4 ($4,679)	732	$7.2 ($4,102)
CA	1,598	$6.0 ($1,576)	68	$0.4 ($2,349)
IL	2,452	$17.0 ($2,890)	-	-
IN	2,787	$21.1 ($3,157)	388	$2.8 ($2,989)
KY	2,291	$28.7 ($5,213)	-	-
LA	4,121	$46.2 ($4,673)	2,649	$24.4 ($3,837)
MD	45	$0.3 ($3,042)	-	-
MI	2,731	$27.7 ($4,230)	-	-
MN	673	$7.9 ($4,910)	-	-
MO	3,103	$25.3 ($3,399)	-	-
MS	1,577	$19.0 ($5,009)	184	$1.4 ($3,243)
NY	389	$2.2 ($2,316)	111	$1.2 ($4,486)
OH	2,611	$24.7 ($3,944)	179	$2.3 ($5,303)
OK	3,575	$37.1 ($4,325)	-	-
PA	3,132	$16.8 ($2,237)	152	$1.5 ($4,013)
TX	4,440	$32.4 ($3,038)	-	-
UT	757	$4.3 ($2,356)	-	-
VA	1,465	$13.6 ($3,861)	98	$1.4 ($5,903)
WI	677	$2.5 ($1,517)	1,472	$11.7 ($3,307)
WV	982	$7.2 ($3,065)	-	-
WY	826	$6.2 ($3,152)	-	-

Figure 2. Geographical Distribution of Ozone Season NOx Reductions and Summary of Reductions by Industry and by State



State	Cement and Concrete Product Manufacturing	Glass and Glass Product Manufacturing	Iron and Steel Mills and Ferroalloy Manufacturing	Pipeline Transportation of Natural Gas	High Emitting Equipment from Tier 2 industries	Total
LA	0	206	0	3,915	2,649	6,769
TX	1,234	1,470	0	1,736	0	4,440
OK	586	190	0	2,799	0	3,575
PA	888	1,379	438	427	152	3,284
IN	468	338	1,829	152	388	3,175
MO	1,296	227	0	1,581	0	3,103
OH	116	451	847	1,198	179	2,790
MI	371	50	38	2,272	0	2,731
IL	234	901	0	1,316	0	2,452
KY	0	0	0	2,291	0	2,291
WI	0	677	0	0	1,472	2,150
MS	0	0	0	1,577	184	1,761
CA	1,162	299	0	137	68	1,666
AR	0	47	6	868	732	1,654
VA	398	174	92	801	98	1,563
WV	230	0	0	751	0	982
WY	446	0	0	380	0	826
UT	520	0	0	237	0	757
MN	0	115	0	558	0	673
NY	142	141	0	106	111	500
MD	0	0	0	45	0	45

Table 5. By Industry, Number and Type of Emissions Units, Total Estimated Emissions Reductions (ozone season tons), Total PPB Improvements, and Costs

		Number of Units by Type			Ozone Season Emissions Reductions (tons) by Type of Unit			Total PPB Improvement Across Downwind Receptors (Max Improvement At Receptor)		Annual Total Cost (million $) (Avg Annual Cost per Ton)
Industry	Region	Boilers	Internal Combustion Engines	Industrial Processes	Boilers	Internal Combustion Engines	Industrial Processes	East	West	
Glass and Glass Product Manufacturing	East	-	-	41	-	-	6,367	0.6962 (0.0865)	0.0015 (0.0004)	$23.2 ($1,520)
	West	-	-	3	-	-	299	0.0009 (0.0001)	0.0332 (0.0066)	$0.9 ($1,293)
Cement and Concrete Product Manufacturing	East	1	-	39	16	-	5,948	0.6382 (0.0707)	0.0018 (0.0006)	$22.4 ($1,566)
	West	-	-	8	-	-	2,128	0.0151 (0.0019)	0.1996 (0.0332)	$6.5 ($1,279)
Iron and Steel Mills and Ferroalloy Manufacturing	East	25	-	15	2,044	-	1,207	1.1556 (0.1750)	0.0000 (0.0000)	$31.2 ($3,995)
Pipeline Transportation of Natural Gas	East	-	296	-	-	22,390	-	1.5373 (0.2815)	0.0057 (0.0020)	$263.2 ($4,898)
	West	-	11	-	-	754	-	0.0086 (0.0010)	0.0586 (0.0170)	$9.1 ($5,037)
Basic Chemical Manufacturing	East	17	-	-	1,698	-	-	0.1655 (0.0107)	0.0002 (0.0000)	$16.3 ($3,999)
Petroleum and Coal Products Manufacturing	East	9	-	-	962	-	-	0.2677 (0.0258)	0.0000 (0.0000)	$7.3 ($3,176)
	West	1	-	-	68	-	-	0.0002 (0.0000)	0.0075 (0.0015)	$0.4 ($2,349)
Pulp, Paper, and Paperboard Mills	East	25	-	-	3,305	-	-	0.3678 (0.0117)	0.0002 (0.0000)	$30.2 ($3,807)

Blue highlights reflect western states information.

Orange highlights reflect Tier 2 industries with impactful boilers.

Table 6. By Industry, Emissions Source Group, Control Technology, Number of Units, Estimated Emissions Reductions (ozone season tons), and Annual Total Cost

Industry	Emissions Source Group	Control Technology	Number of Units	Ozone Season Emissions Reductions	Annual Total Cost (million $)
Cement and Concrete Product Manufacturing	Boilers - < 10 Million BTU/hr; Industrial Processes - Kiln	Ultra Low NOx Burner; Selective Non-Catalytic Reduction	1	117	$0.5
	Industrial Processes - Kiln	Selective Non-Catalytic Reduction	24	3,123	$9.7
	Industrial Processes - Preheater Kiln	Selective Non-Catalytic Reduction	3	342	$1.2
	Industrial Processes - Preheater/Precalciner Kiln	Selective Non-Catalytic Reduction	19	4,510	$17.5
Glass and Glass Product Manufacturing	Industrial Processes - Container Glass: Melting Furnace	Selective Catalytic Reduction	27	1,676	$8.7
	Industrial Processes - Flat Glass: Melting Furnace	Selective Catalytic Reduction	13	4,674	$12.7
	Industrial Processes - Furnace: General	Oxygen Enriched Air Staging	1	52	$0.1
	Industrial Processes - Pressed and Blown Glass: Melting Furnace	Selective Catalytic Reduction	3	264	$2.7
Iron and Steel Mills and Ferroalloy Manufacturing	Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner and Selective Catalytic Reduction	3	383	$4.2
	Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner	6	282	$2.2
	Boilers - > 100 Million BTU/hr	Selective Catalytic Reduction	2	106	$1.2
	Boilers - > 100 Million BTU/hr; Boilers - Blast Furnace Gas	Ultra Low NOx Burner	1	166	$1.0
	Boilers - > 100 Million BTU/hr; Boilers - Coke Oven Gas	Ultra Low NOx Burner	6	360	$2.9
	Boilers - > 100 Million BTU/hr; Boilers - Coke Oven Gas	Selective Catalytic Reduction; Ultra Low NOx Burner and Selective Catalytic Reduction	1	114	$1.7
	Boilers - Blast Furnace Gas	Ultra Low NOx Burner	1	65	$0.4
	Boilers - Blast Furnace Gas; Industrial Processes - Sintering: Windbox; Industrial Processes - Blast Furnace: Casting/Tapping: Local Evacuation; Industrial Processes - Process Gas: Process Heaters	Ultra Low NOx Burner; Selective Catalytic Reduction; Low NOx Burner and Flue Gas Recirculation	1	440	$4.4
	Boilers - Coke Oven Gas	Ultra Low NOx Burner and Selective Catalytic Reduction	3	394	$3.7
	Boilers - Coke Oven Gas; Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner; Ultra Low NOx Burner and Selective Catalytic Reduction	1	116	$1.6
	Industrial Processes - Basic Oxygen Furnace (BOF): Open Hood Stack	Selective Catalytic Reduction	2	185	$1.9
	Industrial Processes - Basic Oxygen Furnace (BOF): Open Hood Stack; Industrial Processes - General	Selective Catalytic Reduction; Low NOx Burner	1	172	$1.7
	Industrial Processes - Basic Oxygen Furnace (BOF): Top Blown Furnace: Primary	Selective Catalytic Reduction	1	50	$0.5
	Industrial Processes - Blast Furnace: Casting/Tapping: Local Evacuation	Selective Catalytic Reduction	1	38	$0.4
	Industrial Processes - General	Low NOx Burner	5	191	$1.7
	Industrial Processes - General; Industrial Processes - Coke Oven or Blast Furnace	Low NOx Burner; Low NOx Burner and Flue Gas Recirculation	1	84	$1.0
	Industrial Processes - Other Not Classified	Low NOx Burner and Flue Gas Recirculation	2	43	$0.1
	Industrial Processes - Sintering: Windbox	Selective Catalytic Reduction	1	60	$0.6
Pipeline Transportation of Natural Gas	Internal Combustion Engines - 2-cycle Clean Burn	Layered Combustion	1	60	$0.8
	Internal Combustion Engines - 2-cycle Lean Burn	Layered Combustion	136	12,645	$165.6
	Internal Combustion Engines - 4-cycle Lean Burn	Selective Catalytic Reduction	41	2,656	$21.6
	Internal Combustion Engines - 4-cycle Rich Burn	Non-Selective Catalytic Reduction	2	147	$0.2
	Internal Combustion Engines - Reciprocating	Non-Selective Catalytic Reduction or Layered Combustion	94	6,329	$72.0
	Internal Combustion Engines - Reciprocating	Adjust Air to Fuel Ratio and Ignition Retard	12	193	$1.1
	Internal Combustion Engines - Reciprocating	Non-Selective Catalytic Reduction or Layered Combustion; Adjust Air to Fuel Ratio and Ignition Retard	1	49	$0.4
	Internal Combustion Engines - Turbine	Selective Catalytic Reduction and Steam Injection	17	929	$8.4
	Internal Combustion Engines - Turbine	SCR + DLN Combustion	3	136	$2.1

Basic Chemical Manufacturing	Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner and Selective Catalytic Reduction	6	786	$7.5
	Boilers - > 100 Million BTU/hr	Selective Catalytic Reduction	2	104	$1.5
	Boilers - 10-100 Million BTU/hr	Ultra Low NOx Burner and Selective Catalytic Reduction	1	133	$1.0
	Boilers - 10-100 Million BTU/hr	Selective Catalytic Reduction	1	43	$0.1
	Boilers - Cogeneration	Selective Catalytic Reduction	1	68	$0.9
	Boilers - Distillate Oil - Grades 1 and 2: Boiler	Selective Catalytic Reduction	1	47	$0.6
	Boilers - Petroleum Refinery Gas	Ultra Low NOx Burner and Selective Catalytic Reduction	2	293	$2.8
	Boilers - Petroleum Refinery Gas	Ultra Low NOx Burner	2	138	$0.8
	Boilers - Subbituminous Coal: Traveling Grate (Overfeed) Stoker	Selective Catalytic Reduction	1	87	$1.1
Petroleum and Coal Products Manufacturing	Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner	1	41	$0.2
	Boilers - > 100 Million BTU/hr; Boilers - Blast Furnace Gas	Ultra Low NOx Burner	1	38	$0.4
	Boilers - Boiler, >= 100 Million BTU/hr	Natural Gas Reburn	1	284	$1.8
	Boilers - Coke Oven Gas	Ultra Low NOx Burner	1	98	$0.6
	Boilers - Petroleum Refinery Gas	Ultra Low NOx Burner and Selective Catalytic Reduction	3	433	$3.8
	Boilers - Petroleum Refinery Gas	Ultra Low NOx Burner	3	137	$0.9
Pulp, Paper, and Paperboard Mills	Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner and Selective Catalytic Reduction	5	618	$6.8
	Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner	3	151	$1.0
	Boilers - > 100 Million BTU/hr	Selective Catalytic Reduction	1	68	$1.2
	Boilers - 10-100 Million BTU/hr	Ultra Low NOx Burner	2	106	$0.5
	Boilers - Bituminous Coal: Cyclone Furnace	Selective Catalytic Reduction	2	662	$3.4
	Boilers - Bituminous Coal: Pulverized Coal: Dry Bottom	Ultra Low NOx Burner and Selective Catalytic Reduction	1	111	$1.1
	Boilers - Bituminous Coal: Pulverized Coal: Dry Bottom; Boilers - > 100 Million BTU/hr	Low NOx Burner; Selective Catalytic Reduction	1	98	$1.4
	Boilers - Bituminous Coal: Spreader Stoker	Selective Catalytic Reduction	3	251	$3.2
	Boilers - Cogeneration	Ultra Low NOx Burner and Selective Catalytic Reduction	2	338	$2.9
	Boilers - Fluid Catalytic Cracking Unit with CO Boiler: Natural Gas	Ultra Low NOx Burner and Selective Catalytic Reduction	2	289	$2.7
	Boilers - Subbituminous Coal: Boiler, Spreader Stoker	Selective Catalytic Reduction	2	348	$3.7
	Boilers - Subbituminous Coal: Spreader Stoker	Selective Catalytic Reduction	1	266	$2.3

Table 7. Estimated Emissions Reductions (ozone season tons), Annual Total Cost, and Average Cost per Ton by Control Technology Across All Non-EGU Emissions Units

Control Technology	OS NOx Reductions	Annual Total Cost	Average Cost per Ton
Adjust Air to Fuel Ratio and Ignition Retard	212	$1,216,435	$2,393
Layered Combustion	12,706	$166,398,282	$5,457
Low NOx Burner	231	$2,092,579	$3,773
Low NOx Burner and Flue Gas Recirculation	200	$2,054,876	$4,288
Natural Gas Reburn	284	$1,843,948	$2,703
Non-Selective Catalytic Reduction	147	$205,808	$585
Non-Selective Catalytic Reduction or Layered Combustion	6,359	$72,383,222	$4,743
Oxygen Enriched Air Staging	52	$95,641	$764
SCR + DLN Combustion	136	$2,060,943	$6,301
Selective Catalytic Reduction	12,239	$74,692,132	$2,543
Selective Catalytic Reduction and Steam Injection	929	$8,439,921	$3,787
Selective Non-Catalytic Reduction	8,076	$28,782,335	$1,485
Ultra Low NOx Burner	1,670	$11,584,405	$2,890
Ultra Low NOx Burner and Selective Catalytic Reduction	3,946	$38,959,490	$4,114

Table 8. Estimated Emissions Reductions (ozone season tons), Annual Total Cost, and Average Cost per Ton by Control Technology Across Non-EGU Emissions Units Grouped by the Tier 1 Industries and Impactful Boilers in Tier 2 Industries

Tier	Control Technology	OS NOx Reductions	Annual Total Cost	Average Cost per Ton
Tier 1	Adjust Air to Fuel Ratio and Ignition Retard	212	$1,216,435	$2,393
Tier 1	Layered Combustion	12,706	$166,398,282	$5,457
Tier 1	Low NOx Burner	211	$1,852,495	$3,656
Tier 1	Low NOx Burner and Flue Gas Recirculation	200	$2,054,876	$4,288
Tier 1	Non-Selective Catalytic Reduction	147	$205,808	$585
Tier 1	Non-Selective Catalytic Reduction or Layered Combustion	6,359	$72,383,222	$4,743
Tier 1	Oxygen Enriched Air Staging	52	$95,641	$764
Tier 1	SCR + DLN Combustion	136	$2,060,943	$6,301
Tier 1	Selective Catalytic Reduction	10,219	$55,575,188	$2,266
Tier 1	Selective Catalytic Reduction and Steam Injection	929	$8,439,921	$3,787
Tier 1	Selective Non-Catalytic Reduction	8,076	$28,782,335	$1,485
Tier 1	Ultra Low NOx Burner	962	$7,172,778	$3,107
Tier 1	Ultra Low NOx Burner and Selective Catalytic Reduction	946	$10,362,549	$4,567
Tier 2	Low NOx Burner	20	$240,084	$5,022
Tier 2	Natural Gas Reburn	284	$1,843,948	$2,703
Tier 2	Selective Catalytic Reduction	2,020	$19,116,944	$3,942
Tier 2	Ultra Low NOx Burner	708	$4,411,626	$2,594
Tier 2	Ultra Low NOx Burner and Selective Catalytic Reduction	3,000	$28,596,941	$3,972

Table 9. Estimated Emissions Reductions (ozone season tons), Annual Total Cost, and Average Cost per Ton by Control Technology Across Non-EGU Emissions Units Grouped by the Seven Individual Tier 1 and Tier 2 Industries

Industry	Control Technology	OS NOx Reductions	Annual Total Cost	Average Cost per Ton
Cement and Concrete Product Manufacturing	Selective Non-Catalytic Reduction	8,076	$28,782,335	$1,485
Cement and Concrete Product Manufacturing	Ultra Low NOx Burner	16	$169,531	$4,410
Glass and Glass Product Manufacturing	Oxygen Enriched Air Staging	52	$95,641	$764
Glass and Glass Product Manufacturing	Selective Catalytic Reduction	6,615	$24,062,362	$1,516
Iron and Steel Mills and Ferroalloy Manufacturing	Low NOx Burner	211	$1,852,495	$3,656
Iron and Steel Mills and Ferroalloy Manufacturing	Low NOx Burner and Flue Gas Recirculation	200	$2,054,876	$4,288
Iron and Steel Mills and Ferroalloy Manufacturing	Selective Catalytic Reduction	948	$9,886,092	$4,345
Iron and Steel Mills and Ferroalloy Manufacturing	Ultra Low NOx Burner	946	$7,003,247	$3,085
Iron and Steel Mills and Ferroalloy Manufacturing	Ultra Low NOx Burner and Selective Catalytic Reduction	946	$10,362,549	$4,567
Pipeline Transportation of Natural Gas	Adjust Air to Fuel Ratio and Ignition Retard	212	$1,216,435	$2,393
Pipeline Transportation of Natural Gas	Layered Combustion	12,706	$166,398,282	$5,457
Pipeline Transportation of Natural Gas	Non-Selective Catalytic Reduction	147	$205,808	$585
Pipeline Transportation of Natural Gas	Non-Selective Catalytic Reduction or Layered Combustion	6,359	$72,383,222	$4,743
Pipeline Transportation of Natural Gas	SCR + DLN Combustion	136	$2,060,943	$6,301
Pipeline Transportation of Natural Gas	Selective Catalytic Reduction	2,656	$21,626,734	$3,393
Pipeline Transportation of Natural Gas	Selective Catalytic Reduction and Steam Injection	929	$8,439,921	$3,787
Basic Chemical Manufacturing	Selective Catalytic Reduction	348	$4,198,768	$5,027
Basic Chemical Manufacturing	Ultra Low NOx Burner	138	$769,564	$2,317
Basic Chemical Manufacturing	Ultra Low NOx Burner and Selective Catalytic Reduction	1,211	$11,326,715	$3,896
Petroleum and Coal Products Manufacturing	Natural Gas Reburn	284	$1,843,948	$2,703
Petroleum and Coal Products Manufacturing	Ultra Low NOx Burner	313	$2,110,773	$2,808
Petroleum and Coal Products Manufacturing	Ultra Low NOx Burner and Selective Catalytic Reduction	433	$3,762,867	$3,624
Pulp, Paper, and Paperboard Mills	Low NOx Burner	20	$240,084	$5,022
Pulp, Paper, and Paperboard Mills	Selective Catalytic Reduction	1,672	$14,918,176	$3,717
Pulp, Paper, and Paperboard Mills	Ultra Low NOx Burner	257	$1,531,289	$2,484
Pulp, Paper, and Paperboard Mills	Ultra Low NOx Burner and Selective Catalytic Reduction	1,356	$13,507,360	$4,151

VI. Request for Comment and Additional Information

In this screening assessment the EPA used CoST, the CMDB, and the 2019 emissions inventory to assess emission reduction potential from non-EGU emissions units in several industries. We identified emissions units that were uncontrolled or that could be better controlled and then applied control technologies to estimate emissions reductions and costs. As noted above, the cost estimates do not include monitoring, recordkeeping, reporting, or testing costs.

As discussed in Section VI.D.2.a of the proposal preamble, the EPA requests comment on the capital and annual costs of several potential control technologies, and in particular whether ultra-low NO_X burners or low NO_X burners are generally considered part of the process or add-on controls for ICI boilers (and how process changes or retrofits to accommodate controls would affect the cost estimates); the effectiveness of low emissions combustion in controlling NO_X from reciprocating IC engines, compared to other potential NO_X controls for these engines; and whether controls on ICI boilers and reciprocating IC engines are likely to be run all year or only during the ozone season.

The EPA also requests comment on the time needed to install the various control technologies across all of the emissions units in the Tier 1 and Tier 2 industries. In particular, the EPA solicits comment on the time needed to obtain permits, the availability of vendors and materials, and the earliest possible installation times for SCR on glass furnaces; SNCR on cement kilns; ultra-low NO_X burners, low NO_X burners, and SCR on ICI boilers (coal-fired, gas-fired, or oil-fired); low NO_X burners on large non-EGU ICI boilers; and low emissions combustion, layered emissions combustion, NSCR, and SCR on reciprocating rich-burn or lean-burn IC engines.

Finally, with respect to emissions monitoring requirements, the EPA requests comment on the costs of installing and operating CEMS at non-EGU sources without NO_X emissions monitors; the time needed to program and install CEMS at non-EGU sources; whether monitoring techniques other than CEMS, such as predictive emissions monitoring systems (PEMS), may be sufficient for certain non-EGU facilities, and the types of non-EGU facilities for which such PEMS may be sufficient; and the costs of installing and operating monitoring techniques other than CEMS.

APPENDIX A – Analysis of Industry Contribution Data

This appendix describes the analyses performed to help focus the non-EGU analytical framework and resulting screening assessment on the most impactful industries.

To inform this analysis, first using the procedure described in Section III, Step 1 above, we estimated contributions from each of 41 industries to each nonattainment and maintenance receptor in 2023 and used these data to calculate the 5 metrics identified in Table A-1.[27,28] A summary of the data for each metric for each industry is provided in Table A-3. These metrics were selected to provide air quality information to inform an evaluation of the magnitude and geographic scope of contributions from individual industries. Metrics 1, 2, and 3 provide information on the magnitude of the contribution. Metric 4 provides information on the geographic scope of the downwind impact, whereas Metric 5 provides information on the geographic scope of upwind state contributions. Of the three air quality metrics we chose to analyze the data for Metric 2, the maximum contribution to any downwind receptor, because this metric aligns with the air quality metric used in Step 2 of the four-step interstate transport framework to identify linked upwind states for further review in Step 3 of the interstate transport framework. To examine the geographic breadth of the industry contributions we chose Metric 4 because that metric provides information on the extent of impacts on downwind air quality problems.

Table A-1. Contribution Metrics for Non-EGU Assessment

1	Total contribution to all downwind receptors
2	Maximum contribution to any downwind receptor
3	Average contribution across all receptors
4	Number of receptors with contributions >= 0.01 ppb
5	Number of linked upwind states with highest industry contribution >= 0.01 ppb

Next, we evaluated the maximum downwind contributions to identify the most impactful industries for further analysis. This approach included a semi-quantitative examination of rank-ordered maximum contributions to identify breakpoints in the data that might serve as an initial screen to eliminate non-impactful industries from further analysis of the contribution data. The distribution of maximum contributions provided in Table A-3 indicate that there is a large range in the values across the 41 industries. Specifically, 5 industries individually contribute more than 0.10 ppb, 3 industries contribute between 0.05 ppb and 0.10 ppb, 11 industries contribute between 0.01 and 0.05 ppb, 8 industries contribution between 0.005 and 0.01 ppb, and 14 industries contribute less than 0.005 ppb.

The rank-ordered maximum downwind contributions from individual industries are shown in Figure A-1. In this figure each point represents the maximum contribution to a downwind receptor from a particular industry. Note that the values for the highest contributing industries are not show in the figure in order to provide greater resolution of the shape of the distribution at the lower end of the values. The declining curve in Figure A-1 exhibits a shape similar to a harmonic distribution. Initially, there is a fairly steep drop in contributions with a breakpoint between roughly 0.04 and 0.06 ppb followed by a steady decline to 0.01 ppb. Beyond 0.01 ppb the shape of the distribution is much flatter. The data suggest that perhaps 0.05 ppb or 0.01 ppb could serve as breakpoints in the data. Based on the distribution

[27] Receptors in California were not considered in evaluating the impacts of non-EGU sources because EPA's contributions from upwind states to these receptors at Step 2 of the four-step interstate transport framework finds that these monitoring sites are overwhelmingly impacted by in-state emissions to a degree not comparable with any other identified nonattainment or maintenance-only receptors in the country. In this regard, EPA is proposing a determination that California receptors are not sufficiently impacted by interstate transport of ozone to warrant proceeding with a Step 3 evaluation of emissions reduction opportunities.
[28] The methods for identifying receptors are described in the Air Quality Modeling TSD for this proposed rule.

of the data we determined that 0.01 ppb provides a meaningful conservative breakpoint for screening out non-impactful industries from the non-EGU contribution analysis. The specific industries with a maximum downwind contribution >= 0.01 ppb are identified in Table A-2.

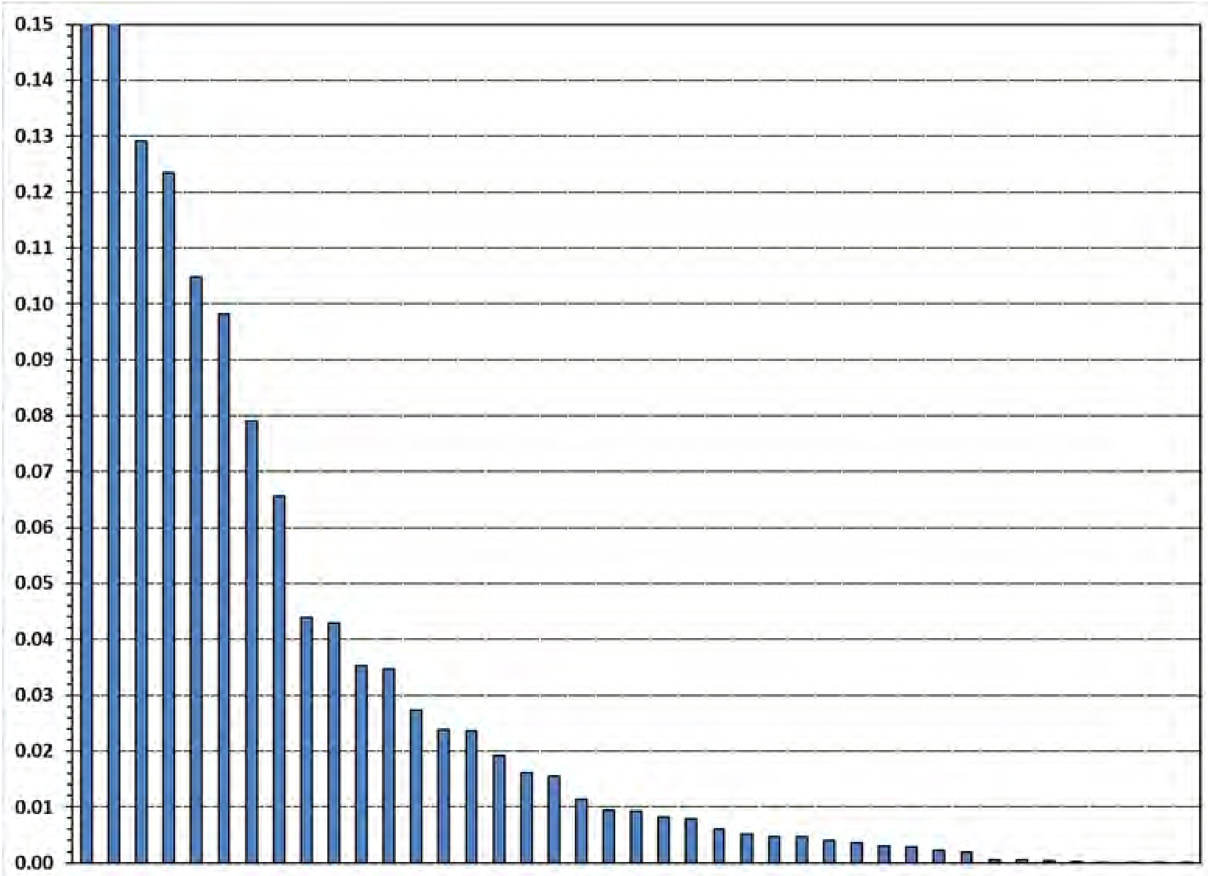


Figure A-1. Rank-ordered maximum downwind contributions from individual industries

We then examined the data for Metrics 2 and 4 for each industry that has a maximum contribution >= 0.01 ppb. The data for Metric 4, as shown in Figure A-2, suggests that there as a breakpoint between those industries that contribute to 10 or more receptors versus those industries that contribute to fewer than 10 receptors. Table A-2 provides the data for Metrics 2 and 4, ranked by the magnitude of Metric 4. The data show that 8 industries contribute >= 0.01 ppb to more than 10 receptors. Of these 8 industries, 5 have a maximum contributions of > 0.10 ppb to one of these receptors. In addition, one industry, Basic Chemical Manufacturing, contributes to only 9 receptors, but the maximum contribution to one of these receptors is >0.10 ppb. Using this information, we grouped the 9 industries into one of 2 tiers based on considering both the magnitude of the contribution and the downwind extent of affected receptors. Tier 1 includes the 4 industries that each have (1) a maximum contribution to any one receptor of >0.10 ppb and (2) a contribution >= 0.01 ppb to at least 10 receptors. Tier 2 includes the 5 industries that each have (1) a maximum contribution to any one receptor >=0.10 ppb but contribute >=0.01 ppb to fewer than 10 receptors, or (2) a maximum contribution <0.10 ppb but contribute >=0.01 ppb to at least 10 receptors.

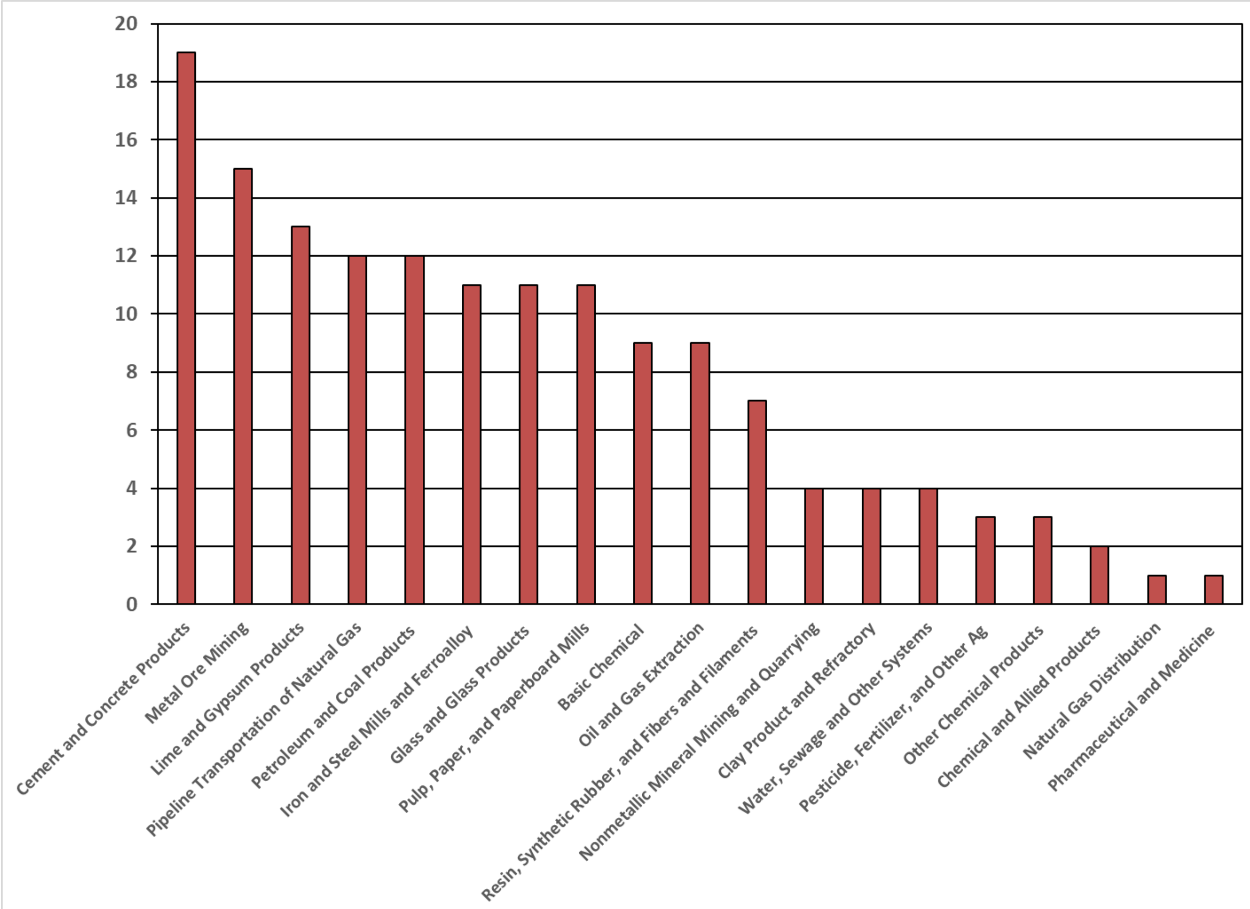


Figure A-2. Number of downwind receptors with contributions >= 0.10 ppb for each industry with a maximum downwind contribution >= 0.01 ppb

Table A-2. Maximum downwind contribution and number of receptors with contributions >= 0.01 ppb

Industry	Max Downwind Contribution	# Receptors with Contributions >= 0.01 ppb
Cement and Concrete Products	**0.231**	**19**
Metal Ore Mining	0.079	**15**
Lime and Gypsum Products	0.066	**13**
Pipeline Transportation of Natural Gas	**0.287**	**12**
Petroleum and Coal Products	0.098	**12**
Iron and Steel Mills and Ferroalloy	**0.129**	**11**
Glass and Glass Products	**0.105**	**11**
Pulp, Paper, and Paperboard Mills	0.043	**11**
Basic Chemical	**0.123**	9
Oil and Gas Extraction	0.035	9
Resin, Synthetic Rubber, and Fibers and Filaments	0.027	7
Nonmetallic Mineral Mining and Quarrying	0.035	4
Clay Product and Refractory	0.024	4
Water, Sewage and Other Systems	0.016	4
Pesticide, Fertilizer, and Other Ag	0.044	3
Other Chemical Products	0.024	3
Chemical and Allied Products	0.019	2
Natural Gas Distribution	0.016	1
Pharmaceutical and Medicine	0.011	1

Table A-3. Estimated Total, Maximum, and Average Contributions from Each Industry, and Number of Receptors with Contributions >= 0.01 ppb for 2023

Industry	# Facilities with Units > 100tpy	# Units > 100 tpy	Ozone Season Emissions	Total Contribution	Max Contribution	Average Contribution	# Receptors with Contributions >= 0.01 ppb	# States with Highest Contribution >= 0.01 ppb
Pipeline Transportation of Natural Gas	144	399	34,343	**1.679**	**0.287**	**0.084**	**12**	**12**
Cement and Concrete Product Manufacturing	61	84	36,244	**1.871**	**0.231**	**0.094**	**19**	**13**
Iron and Steel Mills and Ferroalloy Manufacturing	14	43	4,622	**0.577**	**0.129**	**0.029**	**11**	1
Basic Chemical Manufacturing	38	78	9,612	**0.293**	**0.123**	**0.015**	**9**	**2**
Glass and Glass Product Manufacturing	38	53	12,059	**0.695**	**0.105**	**0.035**	**11**	**7**
Petroleum and Coal Products Manufacturing	47	94	8,163	**0.733**	**0.098**	**0.037**	**12**	**6**
Metal Ore Mining	9	21	17,778	**0.687**	**0.079**	**0.034**	**15**	**3**
Lime and Gypsum Product Manufacturing	31	60	8,856	**0.531**	**0.066**	**0.027**	**13**	**3**
Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing	16	27	3,680	**0.162**	**0.044**	0.008	**3**	1
Pulp, Paper, and Paperboard Mills	46	73	6,773	**0.306**	**0.043**	**0.015**	**11**	**3**
Oil and Gas Extraction	59	139	9,150	**0.207**	**0.035**	**0.010**	**9**	**2**
Nonmetallic Mineral Mining and Quarrying	8	18	3,808	**0.167**	**0.035**	0.008	**4**	1
Resin, Synthetic Rubber, and Artificial and Synthetic Fibers and Filaments Manufacturing	10	16	1,779	**0.152**	**0.027**	0.008	**7**	**2**
Other Chemical Product and Preparation Manufacturing	7	8	683	**0.074**	**0.024**	0.004	**3**	1
Clay Product and Refractory Manufacturing	1	2	1,098	**0.088**	**0.024**	0.004	**4**	1
Chemical and Allied Products Merchant Wholesalers	1	4	573	**0.032**	**0.019**	0.002	**2**	1
Natural Gas Distribution	6	17	1,027	**0.058**	**0.016**	0.003	1	1
Water, Sewage and Other Systems	6	6	375	**0.069**	**0.016**	0.003	**4**	1
Pharmaceutical and Medicine Manufacturing	2	2	300	**0.057**	**0.011**	0.003	1	1
Grain and Oilseed Milling	4	4	376	**0.042**	0.009	0.002	0	0
Lessors of Real Estate	2	2	138	**0.037**	0.009	0.002	0	0
Nonferrous Metal (except Aluminum) Production and Processing	1	4	408	**0.025**	0.008	0.001	0	0
Sugar and Confectionery Product Manufacturing	5	10	1,068	**0.043**	0.008	0.002	0	0
Electric Power Generation, Transmission and Distribution	4	4	296	**0.039**	0.006	0.002	0	0
Engine, Turbine, and Power Transmission Equipment Manufacturing	2	2	112	**0.020**	0.005	0.001	0	0
Agriculture, Construction, and Mining Machinery Manufacturing	1	1	73	**0.012**	0.005	0.001	0	0
Colleges, Universities, and Professional Schools	4	4	263	**0.030**	0.005	0.002	0	0
Coal Mining	5	5	283	**0.015**	0.004	0.001	0	0
Plastics Product Manufacturing	2	2	126	**0.012**	0.004	0.001	0	0
Architectural, Engineering, and Related Services	2	2	117	**0.013**	0.003	0.001	0	0
Motor Vehicle Parts Manufacturing	1	1	62	**0.011**	0.003	0.001	0	0
Advertising, Public Relations, and Related Services	1	1	51	0.009				
Waste Treatment and Disposal	5	5	376	0.010				
National Security and International Affairs	1	1	42	0.002				
Support Activities for Mining	1	1	56	0.003				
Beverage Manufacturing	1	1	45	0.002				
Veneer, Plywood, and Engineered Wood Product Manufacturing	1	1	9	0.001				
Scientific Research and Development Services	1	1	78	0.001				
Alumina and Aluminum Production and Processing	1	1	13	0.000				
Other Food Manufacturing	1	1	45	0.000				
Office Administrative Services	1	1	5	0.000				
Total	591	1,199	164,962	8.77				
Tier 1 Industries	257	579	87,267	4.82				
Tier 2 Industries	171	326	51,182	2.55				
Tier 1 Industries (% of Total)	43%	48%	53%	55%				
Tier 2 Industries (% of Total)	29%	27%	31%	29%				

Legend

	Maximum Contribution	# Receptors with Contributions >=0.01 ppb	Total Contribution	# States with Highest Contribution >= 0.01
Break Points	0.01 to 0.04	> 1 to 9	0.1 to 0.4	> 1 to 9
	>= 0.05	>= 10	>= 0.5	>= 10

1st Tier of Industries for Further Analysis Based on AQ Contributions

These industries (1) have a maximum contribution to any one receptor of >0.10 ppb AND (2) contribute >= 0.01 ppb to at least 10 receptors.

2nd Tier of Industries for Further Analysis Based on AQ Contributions

These industries either have:

(1) a maximum contribution to any one receptor >=0.10 ppb but contribute >=0.01 ppb to fewer than 10 receptors, or

(2) a maximum contribution <0.10 ppb but contribute >=0.01 ppb to at least 10 receptors

APPENDIX B – SUMMARY OF FACILITIES REMOVED in the SCREENING ASSESSMENT for 2026

REGION_CD	FACILITY_ID	Reason for Removal	state	county	site_name	naics_code	naics_description	city
24001	7763811	Closure	MD	Allegany	Luke Paper Company	322121	Paper (except Newsprint) Mills	Luke
06029	4789011	Subject to Consent Decree	CA	Kern	LEHIGH SOUTHWEST CEMENT CO.	327310	Cement Manufacturing	MONOLITH
06029	4789311	Subject to Consent Decree	CA	Kern	CALIFORNIA PORTLAND CEMENT CO.	327310	Cement Manufacturing	MOJAVE
06071	4841311	Subject to Consent Decree	CA	San Bernardino	CEMEX - BLACK MOUNTAIN QUARRY PLANT	327310	Cement Manufacturing	APPLE VALLEY
18093	8225311	Units to be replaced by new kiln by 2023	IN	Lawrence	LEHIGH CEMENT COMPANY LLC	32731	Cement Manufacturing	Mitchell
26007	8127411	Subject to Consent Decree	MI	Alpena	Holcim (US) Inc. DBA Lafarge Alpena Plant	327310	Cement Manufacturing	ALPENA

This revised document replaces the version posted to EPA's website the morning of March 15, 2023. This corrected version is the final document in the rulemaking docket.

United States Environmental Protection Agency

Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards

Response to Public Comments on Proposed Rule [87 FR 20036, April 6, 2022]

Comments, letters, and transcripts of the public hearings are also available electronically through *http://www.regulations.gov* by searching Docket ID EPA-HQ-OAR-2021-0668

FOREWORD

This document provides the U.S. Environmental Protection Agency's (EPA) responses to public comments on the EPA's *Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard.* The EPA published a proposed rule in the *Federal Register* (FR) on April 6, 2022, at 87 FR 20036. The EPA received comments on this proposed rule via mail, email, and through a series of public outreach events, including a virtual public hearing that was held on April 21, 2022.

Copies of all comments received, and the certified transcript prepared for the public hearing held are available at the EPA Docket Center Public Reading Room. Note that out of an abundance of caution for members of the public and our staff, and to reduce the risk of transmitting Coronavirus disease 2019 (COVID-19), the EPA Docket Center and Reading Room are open to the public but require all individuals to complete a self-assessment prior to accessing EPA facilities. The EPA Docket Center and Reading Room are open 8:30 am – 4:30 pm Monday - Friday (except Federal Holidays). For more information and updates on the EPA Docket Center services and the current status, please visit us online at https://www.epa.gov/dockets. In addition, copies of submitted public comments, along with copies of the published hearing transcript are available electronically through Regulations.gov (by searching Docket ID: EPA-HQ-OAR-2021-0668).

More than 112,000 public comments were received on the proposed rule. The EPA Docket Center consolidated mass mail campaigns and petitions into single document control numbers (DCNs), resulting in more than 704 posted comments. Each of these comments was reviewed, and significant comments relevant to this action that were submitted within the comment period (*i.e.,* received on or before June 21, 2022) have been included in this document and summarized below.

It is possible some responses in this Response to Comments (RTC) document may not reflect the language in the preamble and final rule in every respect. Where the response conflicts with the preamble or the final rule, the language in the final preamble and regulatory text should be used for purposes of understanding the scope, requirements, and basis of the final rule. The responses presented in this document are intended to augment the responses to comments that appear in the preamble to the final rule or to address comments not discussed in that preamble. Although portions of the preamble to the final rule are paraphrased in this document where useful to add clarity to the comments or responses, the preamble itself remains the definitive statement of the rationale for the revisions adopted in the final rule. In many instances, responses presented in this RTC document include cross references to responses on related issues that are located either in the preamble or elsewhere in the Response to Comments Document. Accordingly, the RTC document, together with the preamble and final rule, and the rest of the administrative record should be considered collectively as the Agency's response to all the significant comments submitted on the proposed rule.

Contents

Response:

In general, the requirements that the EPA is finalizing for non-EGU industry sources in this rule are cost-effective and feasible, as explained in Section V of the preamble. Section VI of the preamble explains adjustments the EPA has made in the final rule to ensure implementation of these requirements is feasible. Additional time to comply is available on a case-by-case basis, as is the availability of an alternative emissions limit in the case of extreme economic hardship.

The $7,500 marginal cost/ton threshold reflected in the analytical framework in the Screening Assessment was a relative cost/ton level to identify potential emissions-control opportunities for further evaluation. Similar to the role of cost-effectiveness thresholds the EPA uses at Step 3 to evaluate EGU emissions control opportunities, this threshold is not intended to represent the maximum cost any facility may need to expend but is rather intended to be a representative figure for evaluating technologies to allow for a relative comparison between different levels of control stringency. As discussed in Section V.D.2 of the preamble, we acknowledge that there are a range of representative cost-per-ton estimates for the various non-EGU industries, as summarized in the Final Rule Technical Memorandum.

The Agency disagrees that site-specific engineering analysis is necessary before finalizing this rule. The emissions control requirements in this rule are based on widely adopted, well-understood NOx pollution-control techniques and technologies. While the Agency acknowledged that its Screening Assessment was not intended to function as a site-specific engineering analysis, this was not intended to suggest that the Screening Assessment was not reliable for its purpose in identifying where the Agency should focus its attention on obtaining cost-effective NO_X emissions reduction opportunities. See response to comments in Section 2.2.1 (General Criticism of Non-EGU Screening Assessment Methodology) for an overall review of the process by which the EPA ultimately derived the final rule non-EGU requirements.

Comment:

Commenter (0359) is concerned about the inclusion of the iron and steel mills and ferroalloy manufacturing industry and with the controls proposed for this industry. The commenter notes that the EPA does not currently regulate NOx emissions from this source category and has not provided a justification for including this source category in the proposed rule, nor has it provided adequate justification for the proposed emissions standards. The commenter states that the lack of proven technologies and data to establish proposed emissions limits for this source category is especially troubling considering that the EPA proposed emissions standards for 15 separate emissions units and assumed control reduction efficiencies. According to the commenter, the screening assessment did not consider that facilities within this industry have multiple combinations of emissions units to manufacture steel or ferroalloys when it estimated emissions reduction opportunities and related costs. The commenter adds that the cost per ozone season ton of NOx reductions averages $9,500 per ton and as high as $16,910 per ton for each emissions unit (not for the facility) according to the screening assessment. The commenter says that considering facilities in this industry have over 25 emissions units per facility, the cost of these non-technically demonstrated proposed emissions limits are exorbitant for one emissions unit, let alone for the entire facility to attempt to comply. The commenter asserts that the EPA did not address the costs on a per facility basis when it proposed 15 possible types of emissions units within each facility.

Commenter (0504) asserts that the EPA's assessment of NOx emissions reduction potential from "known controls" at EAF steel producers is erroneous and unsupported. The commenter states that although the EPA used CoST data to identify NOx emissions reductions available through "known controls," this parameter does not consider whether the controls are known to be used in any particular industry sector or for any specific emissions unit. According to the commenter, the non-EGU screening assessment does not explain how the EPA identified the five control strategies it believed could be used in the iron and steel sector, but the EPA nonetheless concluded that these five control strategies could reduce ozone season NOx emissions from 39 emissions units at "iron and steel" facilities in the upwind states for up to $7,500 CPT. The commenter relates that of the 39 greater than 100 tpy emissions units in the "iron and steel" sector that the EPA linked to downwind receptors, the EPA identified only three units at EAF steel producers for which there were NOx controls at or below the $7,500 CPT threshold. One of these is a 19 tpy emissions unit at Nucor's facility in Blytheville, Arkansas (identified as "Industrial Processes – Other Not Classified."). According to the commenter, given this vague description, the commenter has no way of identifying this emissions unit or knowing how the EPA determined that the use of "Low NOx Burners and Flue Gas Recirculation" would allow this source to reduce its ozone season emissions by 6 tpy. The commenter stated that the Title V permit for Nucor Blytheville does not identify any 19 tpy NOx sources, and if that unit is any of the various furnaces identified in the permit, the NOx emissions reduction potential is misstated because each furnace already utilizes low NOx burners. The commenter claims that the other two emissions units also appear to be misidentified. The commenter related that the non-EGU screening assessment identifies both of these emissions units as operated by Chaparral Virginia Incorporated in Dinwiddie, Virginia, with one of these emissions units as "Industrial Processes - Blast Furnace: Casting/Tapping: Local Evacuation," despite the facility operating an EAF, and not a blast furnace. According to the commenter, the EPA identifies the other unit only as "Boilers - > 100 Million BTU/hr," but the EPA concludes NO_X from both of these emissions units can be reduced by 90 percent using SCR. The commenter noted that SCR has never been used on an EAF and cannot be feasibly used to control NO_X emissions from an EAF. The commenter adds that even if SCR were technologically feasible for either of these units, it is unrealistic to conclude that SCR could reduce NOx emissions from these sources by 90 percent for less than $7,500 per ton. The commenter adds that the modeling input files place two of these units at the Nucor Blytheville facility and only one at the Chaparral facility, which is the opposite of what is in the non-EGU screening assessment. In short, the EPA misconstrued every single emissions unit attributed to an EAF steel producer. The commenter asserts that the data set the EPA utilized in determining that EAF steel producers in 23 states should be subject to unprecedented NOx limits is shockingly small (3 units at 2 facilities) and 100 percent incorrect. According to the commenter, the EPA cannot, and should not, base any findings or regulatory requirements on such scant, erroneous, and inconsistent data.

Response:

The EPA is not finalizing emissions limits related to blast furnaces, BOFs, ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, and EAFs as proposed. The only emissions units within Iron and Steel Mills and Ferroalloy Manufacturing that the EPA is finalizing requirements for are reheat furnaces and boilers. These comments are further responded to in Section VI.C.3 of the preamble and in the Final Non-EGU Sectors TSD. Note that these comments regarding the alleged infeasibility of certain types of emissions controls on certain types of units in the Iron and Steel Mills and Ferroalloy Manufacturing industry do not undermine the Agency's conclusions in the Screening Assessment that this is an impactful industry nor that those emissions reductions that the Agency concludes are feasible and cost-effective (*i.e.*, at reheat furnaces and boilers in this industry) are not appropriate to require as part of the rule's overall strategy to eliminate significant contribution for the 2015 ozone NAAQS.

2.2.8 Analysis of Municipal Waste Combustion (MWC) Facilities

Comments:

Commenter (0757) asserts that the EPA's rule must not arbitrarily fail to regulate MWCs. The commenter contends that the EPA's failure to include limits for MWCs in its proposed rule is the result of the arbitrary exclusion of MWCs from its screening analysis of non-EGUs, and the final rule must assess and regulate incinerator emissions. The commenter explains that the EPA's threshold criteria for considering a non-EGU industry sector in its Screening Assessment is that the sector includes emissions units that emit over 100 tpy of NOx and that these are uncontrolled sources or sources that could be better controlled at a reasonable cost. According to the commenter, incinerators meet both these criteria, noting that over 90 percent of the incinerators in transport states emit over 100 tpy of NOx, with a per-facility average of 473 tpy of emissions. The commenter also relates that the proposed rule cites findings by the OTC that incinerators could be better controlled at costs well within the proposed rule's cost effectiveness threshold. The commenter states that the EPA excludes this from the assessment and provides no explanation of why. According to the commenter, to the extent that the footnote suggests that the EPA does not consider incinerators to be "non-EGUs" because many of them do produce electricity, that is no rationale, given that the EPA expressly excludes incinerators from its regulation of EGUs. The commenter remarks that the EPA's exclusion of incinerators from the Screening Assessment and from proposed regulation is particularly arbitrary given that incinerators emit more NOx than nearly all of the 41 other non-EGU industries that the EPA did screen and consider. The commenter concludes that it is arbitrary for the EPA to fail to propose MWC emissions limits when it did propose limits on industries with much less NOx impact, and the EPA must rectify this by including incinerator limits in the final rule.

The commenter (0318) encourages the EPA to include municipal waste combustors in the final FIP, which a recent analysis by the commenter indicates can achieve large reductions in NOx emissions below the $7,500/ton cost threshold used with the other non-EGU source sectors.

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August 4, 2023

VIA E-MAIL AND FEDERAL EXPRESS

Michael Regan (Regan.Michael@epa.gov)
EPA Administrator
Office of the Administrator (1101A)
United States Environmental Protection Agency
William Jefferson Clinton Federal Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Petition for Reconsideration and Stay of the Final Rule: Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, EPA–HQ–OAR–2021–0668, 88 Fed. Reg. 36,654 (June 5, 2023)

Dear Administrator Regan:

On behalf of my client, United States Steel Corporation, please find enclosed a petition for reconsideration and stay of the Environmental Protection Agency's final rule Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, EPA-HQ-OAR-2021-0668; 88 Fed. Reg. 36,654 (June 5, 2023).

Please contact me with any questions you may have.

Sincerely,

John D. Lazzaretti

Enclosure

cc: Elizabeth Selbst (selbst.elizabeth@epa.gov)
Gautam Srinivasan (Srinivasan.Gautam@epa.gov)

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BEFORE THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In re: Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023)	))))))	EPA Docket Nos. EPA–HQ–OAR–2021–0668 FRL–8670–02–OAR

PETITION FOR RECONSIDERATION AND FOR STAY OF THE FEDERAL "GOOD NEIGHBOR PLAN" FOR THE 2015 OZONE NATIONAL AMBIENT AIR QUALITY STANDARDS

SUBMITTED BY

UNITED STATES STEEL CORPORATION

Pursuant to § 307 of the Clean Air Act (42 U.S.C. § 7607) and § 705 of the Administrative Procedure Act ("APA") (5 U.S.C. § 705), United States Steel Corporation ("U. S. Steel") submits this Petition for Reconsideration and Stay ("Petition") requesting that the United States Environmental Protection Agency ("EPA") reconsider and revise its Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023) ("Good Neighbor Plan" or "Final Rule").

Under the Clean Air Act, reconsideration is required to address both circumstances that arise after the close of the public comment period but before the time for judicial review, and to allow for notice and comment on elements of the final rulemaking that were not a logical outgrowth of the proposed rule. Both of these elements apply to the Good Neighbor Plan.

The factual circumstances on which the Good Neighbor Plan relied have changed dramatically since the close of the public comment period. Most significantly, courts have stayed EPA's disapproval of SIPs for ten States, denying EPA of the legal authority to promulgate the FIP for almost half of the States EPA assumed would be subject to the rule when it was proposed.

The Final Rule also contains several departures from the Proposed Rule[1] that cannot be considered logical outgrowths of the rulemaking process. These include EPA's reliance on new modelling that was not available to the public until, in some cases, the day the Administrator signed the Final Rule. For iron and steel mills, it also includes a complete rewrite of the regulatory requirements, including the introduction of a new test-and-set process for reheat furnaces that is legally impermissible and unreasonable. For boilers, the Final Rule's applicability to boilers at iron and steel mills significantly departed from the proposed rule (from 100 tons per year potential to emit to 100 MMBTU design capacity—regardless of the unit's potential to emit (with a low use exception). By EPA's own admission, the Final Rule is

[1] Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Primary Ozone National Ambient Air Quality Standard, 87 Fed. Reg. 20,036 (April 6, 2022) ("Proposed Rule").

capturing additional boilers that would not have been subject to the Proposed Rule. Final Rule at 36,819. The regulated community had no opportunity to evaluate the rule's impacts on these newly affected boilers until after the Final Rule was signed. The Final Rule also imposes requirements based on assumptions about timing that are unreasonable and subject only to an extension request process worded in such a way that it will be difficult to apply in many of the cases in which it will be needed.

Overall, the Final Rule shows repeated signs of haste making waste. Even without the stay of so many SIP disapprovals, EPA had two years from the date of SIP disapproval to develop a thoughtful and comprehensive FIP, yet EPA, without giving States an opportunity to cure any alleged SIP defects, took only two months before it signed the Good Neighbor Plan. This was not sufficient, as shown by repeated gaps and ambiguities in the regulatory language. The rule makes almost no mention, for example of how new units and units subject to the Final Rule after August 4, 2023 are to be incorporated. It inconsistently addresses co-fired emission units, exempting boilers, but not reheat furnaces, combusting the same types of fuel, and emission unit averaging, allowing it for engines in pipeline transportation but not reheat furnaces or boilers at iron and steel mills. The record is devoid of any rationale or explanation on these significant differences. Furthermore, it omits regulatory language on key elements such as deadlines for compliance for new units and units that exceed co-firing thresholds, and emission limits for emission units that burn process gases like blast furnace gas and coke oven gas. An administrative stay is necessary until EPA either corrects the numerous errors and gaps that are currently in the hastily drafted rule or rewrites the rule.

Because circumstances have materially changed since the close of the comment period and the Final Rule includes numerous substantive changes that were not subject to public notice and comment, reconsideration of the Good Neighbor Plan is required. Given the lack of record support for the Final Rule, and the serious legal questions raised by EPA's regulation of the iron and steel industry in particular, EPA should on reconsideration withdraw the Final Rule entirely, or at a minimum as to reheat furnaces and boilers at iron and steel mills.

U. S. Steel also requests that EPA stay the Good Neighbor Plan pending reconsideration and pending judicial review. The Good Neighbor Plan has been a highly contentious rulemaking that EPA is now without statutory authority to promulgate in ten States to which it nominally applies. Even in States for which EPA can still legally impose the Good Neighbor Plan, the legal and practical infirmness of the Good Neighbor Plan strongly supports either its total withdrawal or at least significant modification. But under the current deadlines, regulatory parties such as U. S. Steel have already needed to incur compliance costs and will need to continue to incur substantial costs in order to prepare to comply with regulations that likely will never be imposed in their current form. This waste of resources is unnecessary and serves no environmental benefit. A stay is therefore well-supported to allow EPA time to fully evaluate this petition for reconsideration and for judicial review of EPA's Good Neighbor Plan and associated SIP disapprovals to run their course.

Background

The Clean Air Act sets out a "basic division of labor" between EPA and the states in implementing national ambient air quality standards ("NAAQS"). *North Dakota v. EPA*, 730

F.3d 750, 757 (8th Cir. 2013). While EPA is responsible for setting and revising the NAAQS, "States have primary responsibility for attaining those standards within their borders." *Id.* (quotations omitted). In particular, when EPA revises a NAAQS, the Clean Air Act instructs each States to prepare a state implementation plan ("SIP") containing its plan for meeting the revised standard. 42 U.S.C. § 7410(a)(1). If a State submits a complete plan that meets the requirements of the Clean Air Act, EPA must approve it. *Id.* at § 7410(k)(3) ("the Administrator *shall* approve such submittal as a whole if it meets all of the applicable requirements of this chapter") (emphasis added). Only if a States fails to submit a complete SIP or submits a SIP that does not meet the requirements of the Clean Air Act, is EPA authorized to promulgate a federal implementation plan ("FIP") instead. *Id.* at §7410(c)(1). EPA has two years after finding a SIP submission incomplete or inadequate to promulgate the FIP. *Id.* During that time, the State can correct the deficiency. *Id.*

On October 1, 2015, EPA promulgated a revised primary and secondary 8-hour ozone NAAQS of 70 parts per billion ("ppb"). States were thus obligated to submit SIP revisions to EPA by October 1, 2018 that satisfied the requirements of the Clean Air Act. *See* 42 U.S.C. §7410(a)(1). These requirements included the "Good Neighbor" requirement, that State plans:

> (D) Contain adequate provisions—
>
> > (i) prohibiting, consistent with the provisions of this subchapter, any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—
> >
> > > (I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard….

42 U.S.C. §7410(a)(2)(D).

Many states submitted SIPs in 2018 that satisfied this requirement. EPA was required to review these SIPs and approve them within a time period fixed by the Clean Air Act. *See* 42 U.S.C. § 7410(k)(2). Instead, EPA missed its deadline by several years and then, in 2022, proposed to disapprove the SIPs for 19 states based on modeling that EPA had performed in the meantime (the "2016v2" modeling).[2]

Merely proposing a SIP disapproval does not give EPA authority to promulgate a FIP. *See* 42 U.S.C. § 7410(c)(1). Despite this, EPA proceeded to propose its FIP for the Good Neighbor requirement for these 19 states plus several others less than two months after publishing the proposed SIP disapprovals. Proposed Rule at 20,036. EPA used the same 2016v2 modeling as the basis for its Proposed Rule. *Id*. at 20,082. Relying on this modeling, EPA proposed to include not just electric generating units ("EGUs"), as EPA had done in prior Good

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[2] *See, e.g.*, Air Plan Disapproval; Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin; Air Plan Disapproval; Region 5 Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 87 Fed. Reg. 9,838, 9,868 (February 22, 2022).

Neighbor FIPs, but several non-EGU source categories, including iron and steel mills. *Id.* at 20,039.

The Proposed Rule did not contain an adequate technical assessment of the iron and steel industry. As a result, it proposed requirements that were not technically feasible and inappropriate to meet the Good Neighbor requirement of the Clean Air Act. Notably, for reheat furnaces, EPA proposed an emission limit of 0.05 lb/mmBtu based on the unsupported assumption that NOx could be reduced 40% from recent Reasonably Available Control Technology ("RACT") limits through implementation of selective catalytic reduction ("SCR"). *See id.* at 20,145, Table VII.C–3. For boilers at iron and steel mills, EPA proposed an emission limit of 0.20 lb/mmBtu when burning coal, blast furnace gas, or coke oven gas, again without record support. *Id.* at 20,182, Table 1 to Paragraph (c). U. S. Steel and many others submitted detailed comments in response to the Proposed Rule, many of which were not addressed in the Final Rule or EPA's response to comments. U. S. Steel references and incorporates its prior comments. U. S. Steel Comments, EPA-HQ-OAR-2021-0668-0244 and -0798.

EPA published its final SIP disapprovals for 19 States on February 13, 2023,[3] and the Administrator signed the Final Rule only one month later, though it took several more months for the rule to be published in the Federal Register.

The Final Rule contained improvements over the Proposed Rule. U. S. Steel appreciates that significant effort was put into these revisions. But the Final Rule also materially departed from the Proposed Rule in key respects. First, EPA no longer relied on its 2016v2 modeling. Instead, it had developed a different "2016v3" modeling platform and chose to rely on this modeling instead. *See* Final Rule at 36,678. Much of the 2016v3 modeling was not made publicly available until EPA published the final SIP Disapproval in early 2023. Even then, EPA did not make its full modeling results available, choosing instead to withhold the results for model year 2026. *See* SIP Disapproval at 9,344, n. 49 (stating EPA was not providing 2026 results). Second, the emission limitations for reheat furnaces were completely rewritten. Rather than impose a specific NOx limit as proposed, the Final Rule imposes a "'test-and-set' requirement for reheat furnaces that will require the installation of low-NOx burners or equivalent technology" with a work plan requirement to design to a 40% reduction from a baseline to be established by future testing. Final Rule at 36,818. Reheat furnaces that do not obtain an approved work plan are prohibited from operating. *Id.* at 36,880; 40 CFR 52.43(d)(4)(v). Third, for boilers at iron and steel mills, recognizing the material differences in fuels combusted, the Final Rule appropriately imposes no numeric emission limit for combustion of blast furnace gas or coke oven gas. It does, however, limit the applicability of the FIP to a boiler that "receives 90% or more of its heat input from coal, residual oil, distillate oil, natural gas, or combinations of these fuels in the previous ozone season" and provides a method for establishing emission limitations only when combusting these fuels. *Id.* at 36,884; 40 CFR 52.45(c).

Several parties petitioned for judicial review of EPA's SIP Disapproval and moved for a judicial stay of EPA's disapprovals of certain SIPs. Those courts that have ruled on the merits of

[3] Air Plan Disapprovals: Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 Fed. Re. 9,336 (Feb. 13, 2023) ("SIP Disapproval").

these motions have uniformly granted a stay. As a result, the Courts of Appeals have now stayed the FIP as to ten States.[4] These stays prevent the FIP from taking effect in over one third of the States originally subject to the Good Neighbor Plan. Additional motions to stay are still pending and may result in the Good Neighbor Plan not taking effect in additional States. EPA has issued an Interim Final Rule already staying the Good Neighbor Plan as to several States.[5] The Interim Final Rule does not address every State in which the Final Rule cannot be applied, however. It also addresses only the effective date of the Final Rule; it does not address how EPA will confront the numerous other deadlines and requirements in the Good Neighbor Plan that will not be reconcilable with a delayed effective date for the Final Rule.

Standard for Reconsideration

Under the Clean Air Act, reconsideration is *required* "[i]f the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection [during the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." 42 U.S.C. § 7607(d)(7)(b). Courts have found that an objection was "impractical to raise" "when the final rule was not a logical outgrowth of the proposed rule." *Alon Refining Krotz Springs, Inc. v. EPA*, 936 F.3d 628, 648 (D.C. Cir. 2019) (*per curiam*). In other words, when interested parties would not have "anticipated that the change was possible, and thus reasonably should have filed their comments on the subject during the notice-and-comment period." *CSX Transp., Inc. v. Surface Transp. Bd.*, 584 F.3d 1076, 1080 (D.C. Cir. 2009) (internal quotations omitted). An objection is of central relevance to the outcome of the rule if it "provides substantial support for the argument that the regulation should be revised." *Chesapeake Climate Action Network v. EPA*, 952 F.3d 310, 322 (D.C. Cir. 2020).

Further, under the APA, EPA has "broad discretion to reconsider" its regulatory actions "at any time." *Clean Air Council v. Pruitt*, 862 F.3d 1, 8-9 (D.C. Cir. 2017); *see also Trujillo v. Gen. Elec. Co.*, 621 F.2d 1084, 1086 (10th Cir. 1980) ("Administrative agencies have an inherent authority to reconsider their own decisions, since the power to decide in the first instance carries with it the power to reconsider."); *United Gas Improvement Co. v. Callery Properties, Inc.*, 382

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[4] Unpublished Order, *Texas v. EPA*, Case No. 23-60069, ECF 269-1 (May 1, 2023) (staying Texas and Louisiana SIP disapprovals); *Arkansas v. EPA*, Case No. 23-1320, ECF 5280996 (May 25, 2023) (staying Arkansas SIP disapproval); Order, *Missouri v. EPA*, Case No. 23-1719, ECF 5281126 (May 26, 2023) (staying Missouri SIP disapproval); Unpublished Order, *Texas v. EPA*, Case No. 23-60069, ECF 359-2 (June 8, 2023) (staying Mississippi SIP disapproval); *Nevada Cement Co. v. EPA*, Case No. 23-682, ECF 27.1 (July 3, 2023) (staying Nevada SIP disapproval); Order, *ALLETE, Inc. v. EPA*, Case No. 23-1776 (8th Cir. July 5, 2023); Order, *Kentucky v. EPA*, Case No. 23-3216, ECF 39-2 (July 25, 2023) (staying Kentucky SIP disapproval); Order, *Utah v. EPA*, Case No. 23-9509, ECF 010110895101 (July 27, 2023) (staying Oklahoma and Utah SIP disapprovals).

[5] Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards; Response to Judicial Stays of SIP Disapproval Action for Certain States, 88 Fed. Reg. 49,295 (July 31, 2023) ("Interim Final Rule").

U.S. 223, 229 (1965) ("An agency, like a court, can undo what is wrongfully done by virtue of its order.").

Moreover, under both the Clean Air Act and APA, EPA has an obligation to "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'" *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (quotation omitted); *see also* Unpublished Order, *Texas v. EPA*, Case No. 23-60069, ECF 269-1, at 18 (May 1, 2023) (EPA must ensure it acts within a zone of reasonableness and, in particular, has reasonably considered the relevant issues and reasonably explained its decision" and a court must "set aside any action premised on reasoning that fails to account for relevant factors or evinces a clear error of judgment.") (quotations omitted). Action that is not reasonably grounded in the record or that is taken without consideration of important aspects of the problem is arbitrary and capricious. *Id.*; 42 U.S.C. § 7607(d); 5 U.S.C. § 706.

Grounds for Reconsideration

Given the significant changes that have occurred since the end of the public comment period for the FIP and the numerous substantial changes from the Proposed Rule, there are several independent grounds why reconsideration is required in this case.

I. Changed Circumstances Undermine EPA's Factual Foundation for the Final Rule.

When EPA published the Final Rule, it addressed 23 States, including non-EGU industrial sources in 20 States. Final Rule at 36,654. EPA repeatedly emphasized the importance of this broad geographic reach and the need for uniform application of the Good Neighbor Plan to apply across all listed States. *See, e.g.*, Final Rule at 36,673 ("Effective policy solutions to the problem of interstate ozone transport dating back to the NOx SIP Call (63 FR 57356 (October 27, 1998)) have necessitated the application of a uniform framework of policy judgments…."); *id.* at 36,691 ("In the context of addressing regional- scale ozone transport in this rule, the importance of a uniform level of stringency that extends to and includes the [Clean Air Act] section 301(d) FIP areas geographically located within the boundaries of the linked upwind states carries significant force."); *id.* at 36,746 ("*id.* at 36,828 ("the logic of our 4-step interstate transport framework…is designed to bring all covered sources within the region of linked upwind states up to a uniform level of NOx emissions performance during the ozone season"); *id.* at 36,713 ("Considering the core statutory objective of ensuring elimination of all significant contribution to nonattainment or interference of the NAAQS in downwind states and the broad, regional nature of the collective contribution problem with respect to ozone, EPA could not identify a compelling policy imperative to move to a 1 ppb threshold."); *id.* at 36,716 ("the purpose of the Step 2 threshold within the EPA's interstate transport framework for ozone is to broadly sweep in all states contributing to identified receptors above a de minimis level in recognition of the collective-contribution problem associated with regional-scale ozone transport.").

As EPA emphasized:

> the purpose of this rule is to address the interstate transport of ozone on a national scale, and the technical record establishes that the nonattainment and maintenance receptors located throughout the country are impacted by sources of ozone pollution on a broad geographic scale. The upwind regions associated with each receptor typically span at least two, and often far more, states. Within the broad upwind region covered by this rule, the EPA is applying—consistent with the methodology of allocating upwind responsibility in prior transport rules going back to the NO SIP Call—a uniform level of control stringency (as determined separately for linkages existing in 2023, and linkages persisting in 2026). (See section V of this document for a discussion of EPA's determination of control stringency for this rule.) Within this approach, consistency in rule requirements across all jurisdictions is vital in ensuring the remedy for ozone transport is, in the words of the Supreme Court, ''efficient and equitable,'' 572 U.S. 489, 519. In particular, as the Supreme Court found in *EME Homer City Generation*, allocating responsibility through uniform levels of control across the entire upwind geography is ''equitable'' because, by imposing uniform cost thresholds on regulated States, the EPA's rule subjects to stricter regulation those States that have done relatively less in the past to control their pollution. Upwind States that have not yet implemented pollution controls of the same stringency as their neighbors will be stopped from free riding on their neighbors' efforts to reduce pollution. They will have to reduce their emissions by installing devices of the kind in which neighboring States have already invested. *Id.*

Id. at 36,691.

All of these points were made under the assumption that the Final Rule would address EGU emissions from 23 States and non-EGU emissions from 20 States. As of the filing of this Petition, however, SIP disapprovals for ten of those States have been stayed, including: Arkansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Nevada, Oklahoma, Texas, and Utah. Additional motions to stay are pending.[6] These SIP disapprovals are a legal prerequisite for EPA to promulgate the Good Neighbor Plan for those States. 42 U.S.C. § 7410(c)(1). Moreover, because a stay is predicated on the Courts of Appeals finding a likelihood that the petitions in those cases will succeed on the merits, there is a substantial likelihood that the FIP will never apply to most or all of these States. *See Nken*, 556 U.S. at 434. As a result, it is possible that over half the States that EPA asserted are necessary to ensure uniform efforts to reduce interstate transport of ozone, avoid generation and production shifting to less regulated states, and to ensure electric generation reliability, will not be in the Final Rule. Because their presence in the Good Neighbor Plan was a central premise of EPA's promulgation of the Final Rule, this changed circumstance alone requires reconsideration and justifies an administrative stay and a complete withdrawal or rewrite of the Final Rule.[7] Sources in the minority of States

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[6] *See Ohio v. EPA*, Case No. 23-1183 (D.C. Cir); *West Virginia v. EPA*, Case No. 23-1418 (4th Cir.); *Alabama v. EPA*, Case No. 23-11196 (11th Cir.).

[7] EPA has already taken action already to stay the FIP for several of these States. Interim Final Rule at 49,295. This is not sufficient, however. Not only does it address only some of the States to which the Final Rule cannot apply, a stay of the effective date of the Good Neighbor Plan does not address EPA's lack of statutory authority to promulgate the Plan in the first place. The Clean

remaining in the FIP will be irreparably harmed and suffer significant, inequitable costs with no appreciable benefit to the air quality in downwind States. The foundation of the FIP is fatally flawed and does not serve the purpose for which it was intended.

The SIP Disapproval stays also undermine EPA's factual support for the Good Neighbor Plan. The States for which the Good Neighbor Plan is currently stayed represent a large portion of the operations that EPA assumed would be subject to its FIP as it determined what industries to regulate, what costs to consider "significant," and what emission reductions to impose. Final Rule at 36,676 ("EPA here, as it has in prior transport rulemakings for regional pollutants like ozone, identifies a uniform level of emissions reduction that the covered sources in the linked upwind states can achieve that cost-effectively delivers improvement in air quality at downwind receptors on a regional scale."); *id.* at 36,677 ("We find it reasonable in this action to again determine the amount of ''significant contribution'' at Step 3 by reference to uniform levels of cost-effective emissions controls that can be applied across the upwind sources."); *id.* at 36,683 (EPA's analysis of non-EGU emission reduction requirements "relies on evaluation of uniform levels of control stringency across all upwind states to find a level of emissions control that is cost- effective and collectively delivers meaningful downwind air quality improvement"); *id*. at 36,685 ("In this rulemaking's Step 3 analysis, the EPA is measuring emissions reduction potential from improving effective emissions rates across groups of EGUs adopting applicable pollution control measures and selecting a uniform control level whose effective emissions rates deliver an acceptable outcome under the multifactor test (including a finding of no overcontrol at the selected control stringency level)."); *id.* at 36,746 ("The EPA's criteria [for screening non-EGU industries] were intended to identify industries and emissions unit types that on a broad scale impact multiple receptors to varying degrees."). In addition, for EGUs, the number of States in the FIP has a direct correlation to the size of the trading program EPA relies on in the FIP, both to maintain a reasonable regulatory cost and to ensure adequate grid reliability. *See id.* at 36,766, n.295 (the "trading program…depend[s] on the existence of a marketplace for purchasing and selling allowances"); *id.* at 36,789 (noting the importance of "allowance market liquidity" especially during the 2024-2029 period); *id.* at 36,774 (citing "the use of a trading program as the mechanism for achieving…emissions reductions" as a factor in finding no "material risk of adverse impact to electric system reliability" and as the reason why additional accommodation for "reliability-related need" was unnecessary). EPA's policy case modeling also depended on emission reductions from these States. *See generally*, Technical Support Document (TSD) for the Final Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards, at 3 (March 2023). As a result, EPA can no longer rely on factual record and modeling EPA used to develop the Good Neighbor Plan.

The legal and factual basis for the Good Neighbor Plan has so fundamentally changed that the Final Rule can no longer stand on the current administrative record. Because these grounds arose after the public comment period but before the time for judicial review, EPA must

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Air Act speaks plainly to EPA's authority to promulgate a FIP, and it does not authorize EPA to promulgate a FIP at any time before disapproval of a State's SIP submission. 42 U.S.C. § 7410(c)(1). Even if the stay is only temporary, the deadlines in the FIP will not make sense or be reconcilable with the FIP taking effect after August 4, 2023. As a result, the FIP will have to be materially altered through further rulemaking in any event. So, there is no reason for EPA to hold on to what is ultimately an *ultra vires* act.

stay the effectiveness of the FIP and reconsider the FIP. The FIP reconsideration is necessary to determine whether, in light of the stay of EPA's SIP Disapproval for many States, and likely vacatur of EPA's SIP Disapproval, the FIP cannot still be equitably applied to the remaining States. Indeed, given the significant shift in the fundamental facts on which EPA attempted to equitably allocate regulatory burdens since the publication of the FIP, it is likely that reconsideration of the FIP will demonstrate that it must be withdrawn and redone entirely based on new modeling that incorporates the SIPs EPA will likely be unable to disapprove after the pending cases are complete.

II. The Final Rule was Not Promulgated in Accordance with Law and Arbitrarily and Capriciously Relied on Information Added After Public Comment.

EPA was required to include with its Proposed Rule a "statement of basis and purpose" including a summary of:

> (A) the factual data on which the proposed rule is based;
>
> (B) the methodology used in obtaining the data and in analyzing the data; and
>
> (C) the major legal interpretations and policy considerations underlying the proposed rule.

42 U.S.C. § 7607(d)(3). This information is necessary to allow for the "reasonable period for public participation" required by the Clean Air Act. *Id.* at § 760(h). When EPA relies on information that is not made part of the public record in time for meaningful public comment, EPA violates both the spirit and the terms of the Clean Air Act. *Sierra Club v. Costle*, 657 F.2d 298, 400 (D.C. Cir. 1981) (if "documents of central importance upon which EPA intended to rely ha[ve] been entered on the docket too late for any meaningful public comment prior to promulgation, then both the structure and spirit of section 307 [are] violated").

Several aspects of the Final Rule rely on information that EPA did not include in the public record in time for meaningful public comment. Those specific to iron and steel mills are addressed separately below. The most generally applicable addition, however, is EPA's 2016v3 modeling, which was used to support EPA's Step 1 and Step 2 analysis for all affected States. The Proposed Rule was based on modelling that EPA refers to as its "2016v2" modeling. *See* Final Rule at 36,673. But EPA did not rely on the 2016v2 results for the Final Rule. Instead, EPA "revised its 2016v2 modeling platform and input since the platform was made available for comment" to create the 2016v3 modeling. *Id*. at 36,674. It then "reassessed" its modeling results "to inform the final action." *Id*. These were not minor amendments. EPA "evaluated a raft of technical information and critiques of its 2016v2 modeling" and "incorporated updates into the version of the modeling used to support this final rule (2016v3)." *Id*. Further, while EPA released some of its 2016v3 results with the SIP Disapproval in February 2023, it withheld the results for model year 2026, asserting that these results were "not applicable and were not used in this final action." SIP Disapproval at 9,344, n.30. As a result, EPA did not release the full modeling results on which the Final Rule is based until the Administrator signed it in March 2023.

This delay in releasing the modeling that was central to EPA's Final Rule was "highly improper." *Small Ref. Lead Phase-Down Task Force v. EPA*, 705 F.2d 508, 540 (D.C. Cir. 1983); *Kennecott Corp. v. EPA*, 684 F.2d 1007, 1019 (D.C. Cir. 1982) ("the safety valves in the use of such sophisticated methodology [as computer modeling] are the requirement of public exposure of the assumptions and data incorporated into the analysis and the acceptance and consideration of public comment.") (alterations and quotations in original omitted). EPA's rulemaking process requires adequate public notice and an opportunity to comment. *Small Ref.*, 705 F.2d at 547. This includes providing the public with the evidence on which EPA intends to rely. *Id*. at 540.

This was also not the first time EPA switched the information on which it relied after a relevant deadline. The 2016v2 modeling that EPA relied on for the Proposed Rule was itself not introduced until EPA published its proposed SIP disapprovals for 19 States, despite the SIPs having been submitted to EPA years before based on modeling EPA released in 2018. *See, e.g.* 87 Fed. Reg. at 9,840. When EPA switched to reliance on the 2016v2 platform, it gave the public an unreasonably short time to comment, allowing only two months. *See id.* at 9,838. For the Proposed Rule, EPA offered only slightly more time, giving the public less than three months to request, process, verify, and analyze EPA's modeling results, despite numerous requests for more time, including from U. S. Steel. *See* USS FIP Comments at 42. As EPA knows, these models are large data files. They are not made part of the online docket and must be specially requested from EPA. The process takes several weeks to obtain the data and in this case several requests to obtain a full data set. Several more weeks are needed to load and verify it before EPA's modeling can be checked for errors and public comments prepared. Overall, this process typically takes two to three months, and can take longer. Two or even three months after announcing the availability of its 2016v3 modeling was simply insufficient time to allow for meaningful public participation as envisioned by the Clean Air Act. *See* 42 U.S.C. § 7607(h).

When EPA changed the game and switched models again for the final SIP Disapproval and FIP, EPA again gave no prior access to its results. EPA also did not make the complete modeling files immediately available. As raised in a separate petition for reconsideration and stay of EPA's disapproval of Minnesota's SIP (attached as Attachment B), EPA's initial release of 2016v3 modeling data was partial and inadequate to reconstruct the modeling that EPA used for its final determinations. Obtaining the necessary data, as well as checking its accuracy, took several more weeks. In the case of the 2016v3 modeling, U. S. Steel's contractor, Trinity, also needed to contact Ramboll Environ (the CAMx developer) directly to address problems with EPA's source apportionment modeling before it could be checked. This deprived U. S. Steel and the public generally of the opportunity to comment on EPA's modeling. *See Kennecott* 684 F.2d at 1019 (D.C. Cir. 1982) (finding EPA had not provided adequate opportunity for public comment on economic modeling placed in the docket only one week before promulgation of its final regulations); *Riverkeeper, Inc. v. EPA*, 475 F.3d 83, 112-113 (2d Cir. 2007) (finding EPA's Notice of Data Availability insufficient when it omitted information that would have afforded the public the opportunity to make facility-specific comments).

This procedural impropriety was centrally relevant to the outcome of the Final Rule. The 2016v3 modeling forms the basis for "EPA's understanding of projected air quality conditions and contributions" in the Final Rule, which in turn underlie EPA's selection of receptors and State contribution levels. Final Rule at 36,673. Even in the limited time the public has had with the modeling files, significant problems have been identified with EPA's 2016v3 modeling. *See* Petition for Reconsideration and Stay of the SIP Disapproval at 8-14. Correcting for these issues would likely result in at least Minnesota being excluded from the Final Rule.[8]

EPA's modeling for 2026 (which was not released until well after the close of public comment on the Final Rule) is equally important, since it informed both the application of additional emission reductions for EGUs and the introduction of emission requirements for non-EGU industrial sources. *See* Final Rule at 36,654. Indeed, in light of this modeling, EPA found that three States (Alabama, Minnesota, and Wisconsin) would be limited to emission reductions achievable by the 2024 ozone season. Final Rule at 36,660. Other States, including Arkansas and Illinois, had their compliance status change, from being modeled to interfere with attainment in 2023 to being modeled only to interference for maintenance in 2026 modeling. *See id.* at 36,710, Table IV.F–2. This information, had it been available during public comment, would have allowed commenters, including U. S. Steel to address the downward trends in significant contribution EPA has modeled for 2026 and which EPA has itself recognized are significant to identifying maintenance-only receptors. *See* EPA, Considerations for Identifying Maintenance Receptors (Oct. 19, 2018).

EPA's late publication of modeling which is central to its Final Rule violated the procedural requirements of the Clean Air Act and the APA; and justifies reconsideration to allow for full notice and public comment on the modeling supporting the Final Rule.

III. EPA Rushed Promulgation the Good Neighbor Plan in Violation of Cooperative Federalism.

EPA had two years from its SIP Disapproval to promulgate a FIP for most states. 42 U.S.C. § 7410(c)(1). EPA has asserted that it does not need to "postpone its action even a single day" after disapproving a SIP. FIP at 36,689 (*quoting EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489, 509 (2014)). But the Supreme Court was speaking to whether the Clean Air Act required delay absent other considerations. The Supreme Court did not hold that EPA can steamroll State SIP authority simply because Congress did not include a minimum waiting period before EPA can promulgate a FIP. To the contrary, the Supreme Court has repeatedly held that agencies must interpret their statutory obligations "with a view to their place in the overall statutory scheme," and cannot act in a manner that is "'incompatible' with 'the substance of Congress' regulatory scheme.'" *UARG v. EPA*, 573 U.S. 302, 322 (2014) (*quoting FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 133 and 156 (2000)). When, for example, States do not submit SIPs at all, there may be no reason to wait a single day after EPA's finding of incompleteness to promulgate a FIP. Here, 19 states submitted SIPs, appropriately relying on EPA policy and guidance and air modeling that was supported by EPA and available at the time, in a good faith attempt to maintain their primary role as regulators of the Good Neighbor requirement for the 2015 ozone NAAQS. Rather than give these SIPs a full and fair evaluation,

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[8] Since the submission of that petition, additional discrepancies in EPA's air quality modeling have been identified, as are being raised in the separate Petition for Reconsideration and Stay of the FIP being submitted by the Minnesota Good Neighbor Coalition contemporaneously with these comments and only further underscore that, correcting the flawed 2016v3 modeling will likely result in significant changes to the conclusions EPA reached in the Final Rule.

EPA issued late and incomplete modeling, changed its position on published guidance many States used to support their SIPs, gave only limited opportunity for public comment, and rushed out a SIP Disapproval, all with the apparent purpose of paving the way for a FIP that was equally rushed and equally short on public input. Under these circumstances, EPA's decision to simultaneously prepare a SIP Disapproval and FIP violated the Cooperative Federalism at the foundation of the Clean Air Act and was "incompatible with the substance of Congress' regulatory scheme." *UARG*, 573 U.S. at 320 (quotations omitted).

EPA was required to take sufficient time in developing its FIP to ensure that States' primary role in the NAAQS process could be fulfilled. The multiple stays of EPA's SIP Disapproval that have been issued attest to the fact that EPA did not do so here.

EPA should use its reconsideration authority as an opportunity to correct its rush to judgment, and in this instance in particular, considering the scope and complexity of the issues, use the Congressionally-provided two year period for promulgation of FIPs to both work with States on the development of compliant SIPs and, only if necessary, promulgate a FIP.

IV. The Deadlines in the Final Rule Are Incompatible with the Regulation of New Affected Units and Existing Affected Units that Become Subject to the FIP After the Effective Date.

The Good Neighbor Plan applies to two types of emission units: "existing affected units," units constructed on or before August 4, 2023; and "new affected units," units constructed after this date. *See* 40 CFR 52.40(b). Existing affected units are also not all subject to the FIP as of the Effective Date (August 4, 2023). For example, the FIP includes exemptions for low-use boilers and boilers that combust less than 90% natural gas, residual oil, distillate oil, and coal. Final Rule at 36,884; 40 CFR 52.45(b). As a result, even an existing affected unit can become subject to the FIP years after August 4, 2023.[9] The Final Rule, however, makes no provision for these units. With only limited exceptions, compliance dates, submission deadlines, and reporting requirements are recorded as fixed dates in the Final Rule, rather than running from the date of applicability. The result is an ambiguous set of irreconcilable deadlines for units that are not subject to the FIP as of August 4, 2023.

Overall, EPA should reconsider and revise the FIP to comprehensively address these issues, but U. S. Steel identifies several particular examples where post-Effective Date applicability creates particular problems.

A. The Final Rule Does Not Give Sufficient Time for Co-Fired Boilers and Reheat Furnaces.

While the Proposed Rule included emission limits for co-fired boilers, the Final Rule applies only to boilers that combust 90% or more natural gas, distillate oil, residual oil, or coal in the previous ozone season. Final Rule at 36,884; 40 CFR 52.45(b). As discussed in Ground for Reconsideration VIII below, the same exemption should be included for reheat furnaces as well.

[9] Similarly, for existing affected units in states subject to a stay of the FIP, if they will become subject to the FIP at all, it will be at a date after August 4, 2023.

In either case, therefore, there is a possibility that a co-fired unit will lose the exemption if it stops burning process gas at some point in the future for an ozone season. Yet the Final Rule offers no language directly addressing when such units must meet the requirements of the Good Neighbor Plan.

To the extent this would mean that a boiler, for example, will need to be prepared to comply with the Good Neighbor Plan by the start of the next ozone season, this would entail potentially installing CEMS, obtaining permits, designing and installing pollution control equipment, and implementing recordkeeping and reporting requirements within a matter of months, not the nearly four years allowed for boilers subject to the Final Rule as of the Effective Date. For reheat furnaces, it would entail preparing a work plan and having it approved by EPA within a similarly short time period.

The time EPA has allowed for boilers to comply with the Final Rule was meant accommodate the real-world practical requirements of designing, installing and testing new pollution control equipment. *See* NOx Control Installation Timing Report ("Timing Report"). Interim deadlines were fixed to allow each step. As discussed in Ground for Reconsideration XII below, the schedule for boilers does not sufficiently accommodate these requirements and should be extended, but it is arbitrary and capricious to subject units that were exempt from compliance to an even shorter deadline. Indeed, EPA recognized in the Proposed Rule that a "3-year period for installation of post-combustion control technologies is consistent with the statutory timeframe for implementation of the controls required to address interstate pollution under section n110(A)(2)(D) and 126 of the [Clean Air] Act, the statutory timeframes for implementation of RACT in ozone nonattainment areas classified as Moderate or above, and other statutory provisions that establish control requirements for existing stationary sources of pollution." Proposed Rule at 20,101. There is no justification in the record for why a substantially shorter time should apply to emission units that lose an applicable exemption.[10]

EPA must address the lack of deadlines for post-Effective Date boilers and reheat furnaces on reconsideration. In doing so, EPA should allow the same time to achieve compliance as current units subject to the FIP effective August 4, 2023.

B. Compliance Dates for States in which the Good Neighbor Plan has been Stayed Must be Extended.

As discussed above, the Good Neighbor Plan has been stayed, either by court order or Interim Final Rule, in ten states already, with the possibility that additional stays will be issued. In these states, the Good Neighbor Plan will not take effect August 4, 2023. Neither the Final Rule nor the Interim Final Rule, however, makes accommodation for extending the deadlines in the Good Neighbor Plan for emission units subject to a stay.

As one example, owners and operators of reheat furnaces are to submit work plans by August 4, 2024. Final Rule at 36,879; 40 CFR 52.43(d). To do this will reasonably require a

[10] Even for the low-use exemption, which EPA has asserted must result in compliance in one year, there is nothing in the record to support this short of a compliance deadline. Final Rule at 36,884; 40 CFR 52.45(b)(2)(i).

year of work, as EPA anticipated when it set the deadline one year after the Effective Date. Yet owners and operators in a State subject to a stay cannot reasonably be expected to develop work plans until the stay is lifted. This may not occur before August 4, 2024 and, if it does, it will still not leave sufficient time to develop the required content. As a result, to fulfill the requirements of the stay orders currently in place, and to preserve the *status quo* prior to promulgation of the SIP Disapproval, EPA must extend this and other deadlines in the Final Rule to allow reasonable time to comply after the stays are lifted.

C. The Final Rule's Procedures for Requests for Extension and Case-By-Case Emission Limits Do Not Address Post-Effective Date Applicability.

EPA requested comment in the Proposed Rule 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." Final Rule at 20,104. EPA did not propose a process for case-by-case emission limits.

In the Final Rule, EPA promulgated procedures for both requesting an extension of compliance (40 CFR 52.40(d)) and requesting a case-by-case emission limit (40 CFR 52.40(e)). Final Rule at 36,870-71. Neither of these procedures was provided in the Proposed Rule, so it would have been impracticable to raise objections to EPA's procedure during public comment. 42 U.S.C. § 7607(d)(7)(B).

While U. S. Steel supports providing flexibility to owners and operators, both in terms of the compliance schedule and the emission limits in the Final Rule, the procedures EPA has adopted leave significant issues unaddressed. The Final Rule language does not mention new affected units at all, and by including specific dates for applications and dates to which compliance can be extended, the Final Rule does not adequately address existing affected units that become subject to the Good Neighbor Plan after August 4, 2023.

The current language in 40 CFR 52.40(d), for example, allows the "owner or operator of an existing affected unit" to "request an initial compliance extension to a date certain no later than May 1, 2027," almost four years after the Effective Date of the Final Rule. Final Rule at 36,870; 40 CFR 52.40(d)(1). A second extension can be requested to "a proposed compliance date no later than May 1, 2029." *Id;* 40 CFR 52.40(d)(3)(v). These deadlines would be inequitable if applied to emission units that become subject to the Good Neighbor Plan after August 4, 2023, and, of course, do not make sense at all for an emission unit that becomes subject to the Good Neighbor Plan after each date.

EPA included the extension provision because it found "not all facilities may be capable of meeting the control requirements" by 2026, though EPA acknowledged that the "circumstances where an extension may be warranted for any specific facility are unknown at this time and will be evaluated through a source-specific application process, where the need for extension can be established with source-specific evidence." Final Rule at 36,664 and 36,749. There is no rational basis why similar source-specific showings of necessity should not justify a comparable extension for other units that become subject to the Good Neighbor Plan after the Effective Date.

Similarly, in the Final Rule, EPA recognized that "there may be unique circumstances the Agency cannot anticipate that would, for a particular source, render the final emissions control requirements technically impossible or impossible without extreme economic hardship." Final Rule at 36,818. To address this, EPA included "a provision that allows a source to request EPA approval of a case-by-case emissions limit based on a showing that an emissions unit cannot meet the applicable standard due to technical impossibility or extreme economic hardship." *Id.* Since technical impossibility and extreme economic hardship are not limited to existing affected units subject to the Final Rule as of the Effective Date, there is no reasonable basis for EPA to exclude units subject to the Good Neighbor Plan after the Effective Date from the same opportunity. Yet the language EPA chose for the Final Rule requires requests to be submitted "by August 5, 2024." Final Rule at 36,781; 40 CFR 52.40(e)(1).

EPA should reconsider its use of fixed dates in the Final Rule and instead adopt deadlines based on the date of applicability of the FIP to an affected unit.

V. EPA Has Not Justified Including Reheat Furnaces and Boilers at Iron and Steel Mills in the Final Rule.

The Final Rule does not regulate every source of NOx in each upwind State nor should it. Instead, EPA attempted to "focus[] on the most impactful industries and emissions units as determined by [the Agency's] evaluation of the power sector and the non-EGU screening assessment prepared for the proposal….." Final Rule at 36,682. This screening assessment determined which industries would be subject to the Good Neighbor Plan. Indeed, of the 41 industries EPA examined in this screening assessment, EPA selected only nine for inclusion in the Final Rule. *Id.* This screening assessment was also used "[t]o identify appropriate control strategies for non-EGU sources to achieve NOx emissions reductions that would result in meaningful air quality improvements in downwind areas" and to assess control costs. *Id.* at 36,661, 36733. Thus, the screening assessment formed a significant basis for EPA's inclusion of regulations for reheat furnaces and boilers at iron and steel mills in the Final Rule and EPA's selection of appropriate emission reductions for them.

This screening assessment did not identify all emissions from each industry. Rather it focused on "potentially controllable emissions," which it identified by focusing on sources that could provide "the most emissions reductions" at a marginal cost threshold. Screening Assessment at 2. "[W]ell-controlled sources" were expressly to be "excluded from consideration." *Id.* at 3. At the time of the Screening Assessment, EPA assumed, incorrectly, that emissions from co-fired boilers, blast furnaces, casting and tapping, basic oxygen furnaces, sintering, and other processes, all constituted "potentially controllable emissions." *See id.* at 17, Table 6. In the Final Rule, however, EPA appropriately recognizes that additional emission reductions from these sources are not technologically or economically feasible. *See* Final Rule at 36,827 ("the data we have reviewed is insufficient at this time to support a generalized conclusion that the application of NOx controls, including SCR or other NOx control technologies such as LNB, is currently both technically feasible and cost effective on a fleetwide basis for these emission source types in this industry"); *id.* at 36,833 ("The EPA does not have sufficient information at this time to conclude that [boilers] burning more than 10 percent fuels other than coal, residual or distillate oil, or natural gas can operate the necessary controls effectively and at a reasonable cost."). As a result, the Screening Assessment overcounted emissions from iron and steel mills. This required updating before EPA relied on the Screening Assessment results in the Final Rule. It was not. Instead, the Final Rule continues to rely on the same, obsolete and incorrect, Screening Assessment. *Id.* at 36,732-33.

This results in the inconsistent treatment of iron and steel mills as compared with other industries with comparable "potentially controllable emissions," and ultimately, results in a Final Rule that is inconsistent with the record and inequitable impacts.

U. S. Steel already submitted comments on the technical and economic infeasibility of the assumptions made in the Screening Assessment. *See, e.g.*, USS FIP Comments at 13-18. EPA's decision to continue to rely on the Screening Assessment in the Final Rule, however, despite the inaccuracy of its assumptions about the availability of additional emission reductions from the iron and steel mill industry did not arise until the Final Rule and so would have been impracticable to raise in public comments on the Proposed Rule. 42 U.S.C. § 7607(d)(7)(B).

On reconsideration, EPA should revise its Screening Assessment to address only emissions from iron and steel mills associated with reheat furnaces and boilers combusting natural gas, residual oil, distillate oil, and coal. In addition, as discussed in Ground for Reconsideration VI below, the iron and steel industry is subject to many additional and pending NOx reduction requirements that will further limit the availability of additional emission reductions. Since these were not factored into EPA's initial Screening Assessment, reconsideration will present the opportunity for to EPA incorporate a more up-to-date and realistic assessment of reheat furnace and boiler impacts on downwind ozone concentrations, which will likely result in the conclusion that the iron and steel industry, like many other industries, should not be subject to the Good Neighbor Plan.

VI. The Final Rule Did Not Adequately Consider the Cumulative Burdens of Pending EPA Regulations.

The Good Neighbor Plan is only one of many regulations impacting the iron and steel industry, including the same reheat furnaces and boilers subject to the Final Rule, including:

- National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing Amendments, 88 Fed. Reg. 30,917 (proposed May 15, 2023);

- National Emission Standards for Hazardous Air Pollutants: Integrated Iron and Steel Manufacturing Facilities Technology Review, 88 Fed. Reg. 49,402 (proposed July 31, 2023);

- Standards of Performance for Steel Plants: Electric Arc Furnaces Constructed After 10/21/74 & On or Before 8/17/83; Standards of Performance for Steel Plants: Electric Arc Furnaces & Argon-Oxygen Decarburization Constructed After 8/17/83, 87 Fed. Reg. 29,710 (signed Aug. 1, 2023) (https://www.epa.gov/stationary-sources-air-pollution/electric-arc-furnaces-eafs-and-argon-oxygen-decarburization);

- Proposed Amendment to Air Toxics Standards for Coke Ovens Pushing, Quenching and Battery Stacks; and Coke Oven Batteries (Residual Risk and Technology Review, and Periodic Technology Review (proposed rule signed by EPA Administrator Regan on July 31, 2023. (https://www.epa.gov/stationary-sources-air-pollution/coke-ovens-batteries-national-emissions-standards-hazardous-air);

- Reconsideration of the National Ambient Air Quality Standards for Particulate Matter, 88 Fed. Reg. 5,558 (proposed Jan. 27, 2023); and

- EPA Announcement: EPA to Reconsider Previous Administration's Decision to Retain 2015 Ozone Standards, https://www.epa.gov/ground-level-ozone-pollution/epa-reconsider-previous-administrations-decision-retain-2015-ozone.

In developing the Good Neighbor Plan, EPA aimed to incorporate "emissions reductions from on-the-books actions, planned emissions control installations, and promulgated Federal measures that affect anthropogenic emissions" in its 2023 and 2026 emission inventories. Final Rule at 36,698. EPA did not, however, incorporate emission reductions from these and other rules that will significantly impact that NOx emissions from the iron and steel industry.

Equally problematic, while EPA has sought to reflect emission reductions from other regulations, EPA did not incorporate these other obligations into the Good Neighbor Plan's selection of emissions control strategies and calculation of compliance costs. The result is a rule that does not adequately consider the circumstances facing the regulated community. *See* Declaration of Alexis Piscitelli at ¶¶20-28 (attached hereto as Attachment A).

Siloed rulemakings present a jigsaw puzzle of requirements that U. S. Steel and others must piece together under strict compliance deadlines. At a minimum, this is inefficient and not conducive to maximizing environmental benefit. At worst, it can result in conflicting and inconsistent legal requirements. *See id.* As one clear example, EPA is rushing to impose the Good Neighbor Plan to address the 2015 ozone NAAQS while it has already announced its intention to reconsider those standards.[11] It does not make sense to expend millions of dollars in designing and implementing pollution controls to meet standards that EPA is in the process of reconsidering.

On reconsideration, EPA should incorporate consideration of all pending iron and steel industry regulations, which will further support exclusion of reheat furnaces and boilers from a final revised Good Neighbor Plan.

[11] https://www.epa.gov/ground-level-ozone-pollution/epa-reconsider-previous-administrations-decision-retain-2015-ozone.

VII. The August 4, 2023 Deadline for Federally Enforceable Changes to Potential to Emit for Reheat Furnaces is Unreasonable.

The Final rule requires limitations on a reheat furnace's potential to emit to be effective by the Effective Date of the Good Neighbor Plan to be relevant to determining applicability. Final Rule at 36,879; 40 CFR 52.43(b) ("Any existing reheat furnace with a potential to emit of 100 tons per year or more of NOx on August 4, 2023, will continue to be subject to the requirements of this section even if that unit later becomes subject to a physical or operational limitation that lowers its potential to emit below 100 tons per year of NOx."). This aspect of determining potential to emit was not part of the Proposed Rule or a logical outgrowth of the Proposed Rule. As a result, it was impracticable to comment on it during the public comment period. 42 U.S.C. § 7607(d)(7)(B).

EPA has given no reason for adding this provision in the Final Rule in its statement of basis and purpose. This alone violates the procedural requirements of the Clean Air Act. 42 U.S.C. § 7607(d)(6). It is also improper. Long-standing EPA policy approves the use of legally-enforceable limitations on potential to emit to conform emission units to the applicability requirements of EPA's Clean Air Act regulations. *See, e.g.* EPA, Options for Limiting the Potential to Emit (PTE) of a Stationary Source Under Section 112 and Title V of the Clean Air Act (Act), EC-6-1998-29 (Jan. 25, 1995). Removing this option requires a "reasoned explanation," which is absent from the Final Rule. *U.S. Sugar Corp. v. EPA*, 830 F.3d 579, 626 (D.C. Cir. 2016); *see also FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009).

Limiting the time in which potential to emit can be changed is also of questionable value. A federally-enforceable limitation on potential to emit puts an existing affected emission unit in the same position whether the limitation is adopted before or after August 4, 2023. It also puts existing affected units in the same position as new affected units, which can design to a potential to emit after the Effective Date.

EPA has also not applied these requirements consistently across industries. Similar provisions are included in the Final Rule for iron and steel, cement, and glass manufacturing. *See* 40 CFR 52.42(b), 52.43(b), and 52.44(b). But the Final Rule does not impose similar time restrictions on emission units in other non-EGU industries. *See* 40 CFR 52.41(b), 52.45(b), and 52.46(b). The lack of any explanation why certain industries are barred from relying on federally-enforceable limitations after a specific date is a material omission from the Final Rule.

As a practical matter, it is also unfair to subject owners and operators to applicability requirements that require State involvement and quick turnaround. Obtaining federally-enforceable limitations on potential to emit typically requires amendment of State-issued permits. EPA's own Timing Report states that even minor permit modifications can take "a few weeks or months." Timing Report at ES-3. As discussed in Ground for Reconsideration XI below, this is overly optimistic in many cases, particularly when permitting offices are backlogged. FIP applicability should not depend on such factors.

EPA should reconsider the inclusion of this provision in 40 CFR 52.43(b) and remove it. Even if EPA were to conclude that some cut-off for applying physical and operational limitations on potential-to-emit is necessary (and EPA justifies such a cut-off in the statement of basis and purpose as required by the Clean Air Act), EPA should select a date that is both grounded in the emission reduction requirements of the Good Neighbor Plan and that does not unfairly prejudice facilities in States with significant permitting backlogs. For example, under the current Good Neighbor Plan, there is no justification for imposing such a requirement before May 1, 2026, the "compliance date that generally applies to all affected units in the non-EGU industries covered by this final rule." Final Rule at 36,818.[12]

VIII. EPA Should Exempt Co-Fired Reheat Furnaces from the Good Neighbor Plan.

The Final Rule acknowledges that "EPA does not have sufficient information at this time to conclude that [boilers] burning more than 10 percent fuels other than coal, residual or distillate oil, or natural gas can operate the necessary controls effectively and at a reasonable cost." Final Rule at 36,833. EPA does not appear to have considered that similar fuels are used by reheat furnaces, let alone put information in the record to support treating reheat furnaces and boilers that combust more than 10% process gas differently. Indeed, as explained in U. S. Steel's FIP Comments, low-NOx burners were also recently eliminated as a control option for blast furnace stoves fueled primarily by blast furnace gas, and they offer limited potential for emission reduction in light of co-firing and negative energy usage impacts arising from the lower flame temperature with low-NOx burners. thermodynamics of heat transfer to the steel in a reheat furnace. USS FIP Comments at 15 and Exhibit D at § 1.2.5. EPA's finding that there is "[in]sufficient information at this time to conclude that units burning more than 10 percent fuels other than coal, residual or distillate oil, or natural gas can operate the necessary controls effectively and at a reasonable cost" applies equally to reheat furnaces. Yet the Final Rule includes no similar provision excluding reheat furnaces that burn more than 10 percent process gas from the Good Neighbor Plan. U. S. Steel fully supports the exemption of boilers that combust primarily process gas from the Good Neighbor Plan. But having introduced this exemption in the Final Rule, EPA must also apply it consistently.

The applicability provisions for reheat furnaces and boilers were substantially rewritten from the Proposed Rule, and EPA did not raise in the Proposed Rule that it was considering a heat input exemption for process gas-fired emission units. As a result, it would have been impracticable to address EPA's omission of the exemption for reheat furnaces during the public comment period. 42 U.S.C. § 7607(d)(7)(B). On reconsideration, EPA should incorporate a similar exemption for reheat furnaces.[13] Even if EPA determines that reheat furnaces that co-fire process gas should be subject to the Good Neighbor Plan (and provides an adequate explanation for including them), at a minimum, EPA should clarify the determination of potential to emit for these units. As reflected in the emission requirements for boilers, the use of different fuels results in a different NOx emission rate for comparable heat input. *See* 40 CFR 52.45(c). Similarly, in determining potential to emit for co-fired reheat furnaces, a 100 tpy threshold would

[12] The Final Rule technically omits this language from the emission limitation in 40 CFR 52.43(c). This was clearly an omission and should be corrected on reconsideration as well, to make clear that the emission limit applies "[b]eginning with the 2026 ozone season" or, as discussed in Ground for Reconsideration IV above, within three years following the date the Good Neighbor Plan becomes applicable to an emission unit.

[13] As discussed in Ground for Reconsideration IV above, deadlines should also be included in 40 CFR 52.43(c) for furnaces that lose this exemption after the Effective Date.

capture differently-sized units depending on whether potential to emit is determined based on combustion of natural gas or process gas.

IX. The Work Plan Process for Reheat Furnaces is *Ultra Vires* and Violates Due Process.

A Good Neighbor implementation plan is to contain emission limitations ("prohibit[ions]" on "emissions activity"). 42 U.S.C. § 7410(a)(2)(D)(i). The Clean Air Act sets forth specific procedural requirements EPA must follow to impose these emission limitations. 42 U.S.C. § 7607(d). This includes publication of a proposed rule in the Federal Register, provision of a statement of basis and purposes, creation of a public docket of supporting material, public comment, and response to significant comments. *Id.* at § 7410(d)(3)-(6). Public participation must be for "a reasonable period" and by "at least 30 days" unless expressly provided for otherwise in the Clean Air Act. *Id*. at § 7607(h). Final emission limitations are also subject to judicial review. *Id.* at § 410(d)(7).

The Final Rule does not impose emission limitations on reheat furnaces. Instead, it imposes a "test-and-set requirement for reheat furnaces that will require the installation of low-NOx burners or equivalent technology." Final Rule at 36,818. Specifically, it requires owners and operators to submit a work plan and "establish an emissions limit in the work plan that the affected unit must comply with." *Id.* at 36,879; 40 CFR 52.43(d)(3). U. S. Steel agrees with EPA's conclusion that "[d]ue to variations in the emissions rates that different types of reheat furnaces can achieve," EPA should not "finaliz[e] one emissions limit for all reheat furnaces." Final Rule at 36,828. And while EPA recognized that furnace-specific factors make a universal one-size-fits-all approach inappropriate for reheat furnaces, it somehow disregarded these factors when imposing a universal reduction mandate in the Final Rule. A universal reduction of 40% from baseline is not appropriate because it does not take into account what is achievable for each reheat furnace, including what the baseline value actually is—whether, for example, it is 0.12 lb/MMBtu or 0.24 lb/MMBtu, what limits there are on the type of NOx reduction technology that can be used, what fuels the reheat furnace uses, what other pollution control technologies are already in place, or other factors that would make a minimum 40% reduction on some units technically or economically infeasible. *See* Attachment A at ¶¶11-12. EPA's own analysis of low-NOx burners shows this bearing true, as it merely cites to an application of low-NOx burners at a reheat furnace that achieved a 20% reduction in NOx. *See* Proposed Rule at 20,145, Table VII.C-3. EPA has not provided any basis for the 40% reduction requirement—and such a requirement is devoid of any explanation and is therefore arbitrary and capricious.

U. S. Steel appreciates that EPA was looking to provide flexibility through the work plan process in the Final Rule, both on phased construction timeframes and the final emission limits. The logical result or outgrowth of finding that there is insufficient information in the record to support an emission limit for reheat furnaces, however, is to exclude reheat furnaces from the Good Neighbor Plan—not to establish a mandate the reduce NOx by 40% from baseline. EPA cannot put in a placeholder and then use a work plan process to develop future record support. 42 U.S.C. § 7607(d)(6)(C) ("The promulgated rule may not be based (in part or whole) on any information or data which has not been placed in the docket as of the date of such promulgation."). The procedure EPA has included in the Final Rule for establishing the final emission limits for reheat furnaces falls short of these requirements. U. S. Steel and others similarly situated had no opportunity to comment on the Work Plan requirement or the 40% reduction mandate.

The work plan process in the Final Rule also raises serious Due Process concerns. The Final Rule provides that the Administrator will determine completeness of a work plan within 60 calendar days (40 CFR 52.43(d)(4)(i)), and then, within 60 calendar days after notification of a complete work plan, notify the owner and operator via CEDRI or analogous electronic submission system whether EPA approves the work plan (40 CFR 52.43(d)(4)(iv). Final Rule at 36,879-80. The Final Rule does not say what is to be done if the Administrator approves the work plan, but if the Administrator does not approve it, the owner or operator has only 15 calendar days to present in writing additional information or arguments, after which the Administrator can issue a final decision disapproving the work plan. *Id.* at 36,880; 40 CFR 52.43(d)(4)(iii). If the Administrator disapproves a work plan or finds or work plan was not timely submitted or completed, "[e]ach day that the affected unit operates following such disapproval of failure to submit shall constitute a violation." *Id.*; 40 CFR 52.43(d)(v).

This work plan process raises several concerns. First, this effectively imposes an emission limit of zero, unless an owner or operator can demonstrate to EPA's satisfaction that a higher limit should apply. This turns the rulemaking process on its head and finds no support in the Clean Air Act.

Second, the procedural rights it affords clearly fall short of what would be required for a prohibition on operation. Even in the case of a 126 petition, through which the Clean Air Act expressly authorizes EPA to limit the emissions of a particular "major source or group of major sources" to prevent "violation of the prohibition of section 7410(a)(2)(D)(ii)," the Clean Air Act requires both a public hearing and the provision of at least three months for a source to come into compliance while continuing to operate. 42 U.S.C. § 7426(b). There is no justification for imposing an even more draconian ban—with less process—through implementation of a FIP that is expressly required to avoid over-control. *See, e.g.*, Final Rule at 36,704; *EME Homer City*, 572 U.S. at 523.

Third, EPA's work plan process circumvents the notice and comment rulemaking procedure EPA is required to follow in 42 U.S.C. § 7607(d), including publication of both the proposed and final emission limit in the Federal Register, provision of at least 30 days for public comment, a requirement that EPA will respond to all significant comments, requirement that issuance of the final decision and statement of basis will be published in the Federal Register, and that EPA's final decision will be subject to judicial review. In the regional haze test-and-set process EPA adopted for certain taconite furnaces, for example, the emission limits to be set become enforceable "only after EPA's confirmation or modification of the emission limit in accordance with" procedures that include EPA taking "final agency action by publishing its final confirmation or modification of the NOx limit in the Federal Register." *See, e.g.*, 40 CFR 42.1235(b)(1)(ii)(A)(1)-(7). No such protections are afforded in the Good Neighbor Plan.

Finally, even if EPA's work plan process could be squared with the procedural requirements of the Clean Air Act, the current regulations do not provide sufficient clarity on the grounds on which the Administrator will determine whether a work plan "is complete, that is, whether the request contains sufficient information to make a determination" or fails "to satisfy the requirements of paragraphs (c) and (d)(1) through (3) of this section." Final Rule at 36,880; 40 CFR 52.43(d)(4)(i) and (v). As currently promulgated, the work plan process is so vague as to necessarily result in an arbitrary and capricious decision.

This work plan process was not proposed in the Proposed Rule and U. S. Steel had no notice that EPA was considering it prior to the Final Rule.[14] EPA must grant reconsideration to address the flaws in its work plan process for reheat furnaces and should, on reconsideration, remove reheat furnaces entirely from the Good Neighbor Plan.

X. The Work Plan Requirements for Reheat Furnaces Are Not Supported by the Record.

As noted in Ground for Reconsideration IX above, EPA did not propose a work plan process for reheat furnaces in the Proposed Rule. As a result, it would have been impracticable to comment on the target emission reductions and schedule in the Final Rule during public comment. As discussed in Ground for Reconsideration IX above, the reheat furnace requirements should be withdrawn entirely. If they are not, EPA must reconsider the requirements in these aspects of the Final Rule as well.

A. A Minimum 40% Reduction in NOx from Installation of Low-NOx Burners is Not Justified by the Record.

The Final Rule requires existing affected units to "install and operate low-NOx burners or equivalent alternative low-NOx technology designed to achieve at least a 40% reduction from baseline NOx emissions." 40 CFR 52.43(c). But EPA nowhere explains where this 40% target comes from. In the Proposed Rule, EPA proposed a 40% reduction through selective catalytic reduction ("SCR"). Proposed Rule at 20145, Table VII.C-3. Commenters, including U. S. Steel, submitted information showing that SCR is not technically feasible and its use was not supported by the record. *See, e.g.*, USS FIP Comments at 14-15. In the Final Rule, EPA has switched to reliance on low-NOx burners. Final Rule at 36,818. But EPA has not pointed to evidence that a 40% reduction is feasible for low-NOx burners. To the contrary, the Proposed Rule gives as an example a reheat furnace with low-NOx burners at Sterling Steel, which achieved less than a 20% reduction from the Ohio NOx RACT limit EPA used as its baseline for determining feasible NOx reductions. *See* Proposed Rule at 20145, Table VII.C-3.

As discussed in Ground for Reconsideration VIII above, EPA should exclude co-fired reheat furnaces from the Good Neighbor Plan entirely. If it does not, the 40% reduction goal presents an additional problem for these units. There is nothing in the record on their emission reduction potential from installation of low-NOx burners. Indeed, some process gases (like blast furnace gas) are by nature low-NOx. A 40% reduction is not demonstrated as feasible from these units. Combustion of coke oven gas introduces additional complications. NOx generation

[14] The only emission units subject to a work plan in the Proposed Rule were taconite furnaces in the metal ore mining industry. Proposed Rule at 20,182. This was based on a work plan process negotiated by EPA as a resolution to various rulemaking challenges to the 2016 Minnesota Regional Haze Federal Implementation Plan. A proposal to apply a specific work plan process to one industry is not notice that EPA is considering applying a different work plan process to different emission units in a different industry.

can vary significantly based on the nitrogen content of the process gas. This variability would have to be factored into determining an emission reduction potential for reheat furnaces that burn coke oven gas.

More generally, it is inconsistent with the work plan process for EPA to impose a minimum emission reduction requirement across all units. If the purpose of the work plan is to evaluate what is feasible for each unit, *see* 40 CFR 52.43(d)(3), the engineering evaluation of what is feasible should guide the emission reductions. As a result, if a work plan process is included following reconsideration, EPA should require installation of "cost effective emission controls" in accordance with the work plan, not a predetermined target reduction. *See, e.g.* Final Rule at 36,746.

B. The Schedule for Reheat Furnaces is Not Feasible.

The Final Rule requires owners and operators to submit a work plan by August 5, 2024. Final Rule at 36,879; 40 CFR 52.43(d)(1). The work plan approval process involves two rounds of EPA review, for completeness and approval, which will result in a final work plan by late 2024 or early 2025. *Id.*; 40 CFR 52.43(d)(4). Certification of installation is then due March 30, 2026. *Id.*; 40 CFR 52.43(g). This leaves approximately 15-16 months from work plan approval to completion of installation.

In U. S. Steel's experience, this is greatly insufficient. U. S. Steel has prepared a schedule for installation of low-NOx burners on the four reheat furnaces at U. S. Steel – Gary Works' 84" Hot Strip Mill. *See* Attachment A at Attachment 1, Appendix A. Even without the delay inherent in waiting for work plan approval, installation of low-NOx controls is expected to take until May 2027. Comparing this to EPA's assessment of the timing for compliance in the Timing Report, which was released with the Final Rule, it is clear that EPA underestimates the time required for initial evaluation and work plan approval, the likely time needed for permitting, and the time needed for fabrication and construction of pollution control requirement.

1. EPA's Timing Report Does Not Consider Work Plan Approval

The Timing Report assumes that implementation can begin in Month 3 (November 2023 for the Final Rule). Timing Report at 22. As noted above, however, EPA will not approve work plans until December 2023 or January 2024, assuming no delay on EPA's part in reviewing and approving work plans. Approval could take significantly longer if EPA is delayed or there is a need for supplemental information. Nowhere in the Timing Report does EPA appear to have considered the impact of this delay. Work plans are not mentioned at all and there is no time provided for their approval. Given EPA's assumption that all work can be completed in 15 months, the loss of even two months is significant and undermines EPA's compliance deadlines for reheat furnaces.

2. The Timing Report Underestimates Vendor Availability.

The Timing Report recognizes that vendor demand and capacity can introduce delays. Timing Report at 41. The Report appears to conclude that vendor capacity will not be a cause of delay, but U. S. Steel is already experiencing problems obtaining vendor quotes and finding and scheduling qualified union contractors. *See* Attachment A at ¶¶9 and 10. These issues are likely to get worse as EPA continues to implement additional Clean Air Act regulations that impose additional obligations on the iron and steel industry. *See id.* at ¶¶26-27. In addition, EPA's Timing Report only evaluates vendor availability for SCR and SNCR installation. Timing Report at 41-42. It does not assess the availability of low-NOx burner vendors for work on reheat furnaces, which is the technology EPA selected in the Final Rule. Here too U. S. Steel has found difficulty obtaining sufficient vendor quotes to proceed. Attachment A at ¶9.

3. The Final Rule Underestimates Permitting Times.

The Timing Report assumes that permitting can be completed in six months, despite noting that permitting can take over a year and may take longer. Compare Timing Report at 22 with ES-3. The Report does not reconcile these discrepancies. It appears to simply conclude that state permitting offices should be able to move quickly as long as they are not backlogged with other work. But EPA does not evaluate what other work States will be doing in the same timeframe. In Indiana, for example, EPA estimates that the Good Neighbor Plan will result in an additional 51 permit applications for non-EGU control installations alone. Timing Report at 44, Table 4-15. EPA assumes this will take 2,200 hours of work, which EPA assumes Indiana can compress into six months without any consideration of other permitting requirements that may arise in the same timeframe.

Combined, these delays make the schedule in the FIP highly unlikely. On reconsideration, if EPA retains a work plan process, EPA should revise the compliance schedules to allow sufficient time for work plan approval, engineering, permitting, installation, and testing prior to the certification date. At a minimum, this should allow for implementation through the 2027 ozone season.

XI. The Applicability Determination for Boilers at Iron and Steel Milles was Not a Logical Outgrowth of the Proposed Rule.

The Proposed Rule proposed to regulate boilers at iron and steel mills that "directly emits or has the potential to emit 100 tons per year or more of NOx." Proposed Rule at 20,181. EPA gave no notice that it was considering other applicability thresholds for boilers at iron and steel mills. In the Final Rule, however, EPA switched the applicability requirement to "a design capacity of 100 mmBtu/hr" and other restrictions. Final Rule at 36,884; 40 CFR 52.43(b). This was a significant departure, which EPA acknowledges captured more boilers than originally proposed. *See id.* at 36,819. EPA afforded the regulated community no opportunity to review the effects and applicability on these additional boilers until the Final Rule was released, however. This alone was improper. *Small Ref.*, 705 F.2d at 547 ("the final rule must be a logical outgrowth of the proposed rule") (quotations omitted). Furthermore, EPA has not adequately supported its contention that a boiler with a PTE of 100 tons is comparable to a boiler with a design capacity of 100 MMBtu/hr. A boiler's design capacity is not necessarily correlated with a boiler's design capacity. Frequently, based upon changes at facilities in which steam needs are reduced, operators do not use boilers near their design capacity. The assumption to correlate 100 tons to 100 MMBtu/hr is inappropriate.

XII. The Schedule for Boilers to Install Low-NOx Controls is Infeasible.

The Final Rule requires compliance testing to be completed no later than May 1, 2026. Final Rule at 36,885; 40 CFR 52.45(d)(1)(i). Since compliance testing requires 30 days, controls must be installed by April 2026. *Id.*; 40 CFR 52.45(d)(1). Even for states in which the Final Rule has not been stayed, this is not enough time to plan, design, approve, permit, install, and test new controls.

EPA's Timing Report estimates the Good Neighbor Plan will result in the installation of pollution controls on over 160 boilers in the same 31-month period. Timing Report at 32. Delays associated with stays of the SIP Disapproval will compress this period for many States.

For the iron and still industry, this will be on top of addressing reheat furnaces and several additional rules currently being promulgated. *See* Ground for Reconsideration VI above. The result is that the regulated community, permitting authorities, and vendors will likely be overwhelmed.

On reconsideration, EPA should reassess the timing needed to comply with the Good Neighbor Plan in light of the unenforceability of the Good Neighbor Plan in many states during judicial review of the SIP Disapproval, more realistic permitting times, and after additional consideration of the multiple obligations arising from other Clean Air Act regulations being promulgated by EPA.

XIII. The Heat Input Requirement for Boilers Does Not Adequately Provide for Outages of Sources of Process Gas.

EPA appropriately exempted from the Good Neighbor Plan a boiler that "receives 90% or more of its heat input from coal, residual oil, distillate oil, natural gas, or combinations of these fuels." Final Rule at 36,884; 40 CFR 52.45(b)(1). In the Final Rule, EPA added "in the previous ozone season," which helps clarify how heat input is to be averaged. *Id.* This addition, however, does not adequately accommodate outages for sources of process gas.

An extended idling of blast furnace operations, for example, can result in periods of blast furnace gas curtailment that could cause a boiler to exceed the 90% heat input threshold in a single ozone season. Bringing a co-fired boiler into the Good Neighbor Plan based on an exceedance of the 90% heat input requirement for a single ozone season, when it will return to normal operation shortly thereafter, makes little sense. Installing controls that are not technically or economically feasible to operate during normal operation is inconsistent with the record and will not be environmentally beneficial. The time it will take to plan, design, permit, install, and test controls will also take longer than the single year such a unit might need to operate on below 10% process gas.

On reconsideration, EPA should accommodate extended outages, either by allowing owners and operators to exclude from the heat input calculation short periods when alternative fuels are not available, or by providing a longer averaging period, such as the three-ozone season average the FIP provides for low-use boilers in 40 CFR 52.45(b)(2).

XIV. EPA Has Not Adequately Explained How Compliance Is Determined for Co-Fired Boilers.

The Final Rule exempts a boiler that "receives 90% or more of its heat input from coal, residual oil, distillate oil, natural gas, or combinations of these fuels." Final Rule at 36,884; 40 CFR 52.45(b)(1). If EPA concludes that they should be regulated, it must provide an appliable emission limit supported by the record. While U. S. Steel agrees that the introduction of process gases can and does interfere with the applicability and effectiveness of controls, it also affects the emission rates a unit can achieve. The Final Rule provides that heat input is to be calculated for natural gas, residual oil, distillate oil, and coal based on a per fuel basis. *Id.*; 40 CFR 52.45(c). EPA conducted no analysis of what emission limit can be achieved at a co-fired unit. If EPA intends to regulate these sources, it needs to have an applicable emission limit that is justified by the administrative record. The absence of any justification in the current record would render applying one of the above emission limits to combustion of process gas arbitrary and capricious.

XV. EPA Should Have Made Facility Wide Averaging Plans Available for Reheat Furnaces and Boilers.

In the Final Rule, EPA introduced the concept of a "Facility-Wide Averaging Plan" to "enable owners and operators of affected units to take costs, installation timing needs, and other considerations into account in deciding which [units] to control." Final Rule at 36,759-60. Facility-wide averaging was not proposed for any industry in the Proposed Rule. As a result, U. S. Steel did not have notice EPA was considering emission unit averaging for the Good Neighbor Plan. EPA made this option available in the Final Rule, but only for emergency engines in the Pipeline Transportation of Natural Gas industry. *Id.* EPA provided no justification for excluding other industries and sources from the option of using an averaging plan.

There is no practical justification for excluding reheat furnaces and boilers at iron and steel mills from being able to use of an averaging plan. U. S. Steel, for example, has long used averaging at emission units to facilitate permitting and maximize compliance efficiencies, including for boilers and reheat furnaces. *See* Attachment A at ¶¶29-31.

On reconsideration, EPA should allow reheat furnaces and boilers at iron and steel mills to take advantage of similar efficiencies and by being able to request a Facility-Wide Averaging Plan for boilers and reheat furnaces that are subject to the Final Rule.

Ground for Stay of the Good Neighbor Plan

EPA has authority to stay the Good Neighbor Plan both pending reconsideration and pending judicial review. First, a stay pending reconsideration can be granted for three months. 42 U.S.C. § 7607(d)(7). Second, EPA has authority under the APA to stay the Good Neighbor Plan pending judicial review.

I. EPA Should Stay the Good Neighbor Plan Pending Reconsideration.

The Clean Air Act provides that, if EPA grants reconsideration of a rule, "[t]he effectiveness of the rule may be stayed during such reconsideration…by the Administrator or the court for a period not to exceed three months." 42 U.S.C. § 7607(d)(7)(B). EPA may also issue a longer stay pending reconsideration under the APA. 5 U.S.C. § 705; 42 U.S.C. § 7607(d)(1). A stay pending reconsideration is justified here.

As discussed above, the Final Rule suffers from critical flaws. It was promulgated in violation of Clean Air Act requirements for many of the States to which it nominally applies. It is based on centrally-relevant information that was not subject to notice and comment, in violation of the procedural requirements of the Clean Air Act. It contains numerous omissions and contradictions that require clarification before the Good Neighbor Plan can reasonably be applied to reheat furnaces and boilers at iron and steel mills. And it overcontrols upwind State emissions, improperly shifting the burden of attainment the NAAQS from downwind States. These issues must be addressed before the FIP is enforced against owners and operators of affected units.

A stay of three months will allow EPA the time needed to reconsider the Good Neighbor Plan and incorporate the above grounds for reconsideration in a decision either to wholly withdraw the Final Rule or to publish a revised FIP that is legally and technically defensible. If additional time is needed, EPA should exercise its authority under the APA to extend the stay to allow sufficient time for full reconsideration and (as discussed below) judicial review.

A stay will also not unduly impact downwind states. The FIP cannot be enforced in ten states during the pendency of the current SIP Disapproval litigation, which will likely not be resolved for the duration of a reconsideration stay. At the same time, it will inequitably affect the remaining States subject to the Good Neighbor Rule, which is inconsistent with the spirit and intent of the Clean Air Act and EPA's stated intent in the Good Neighbor Rule itself to equitably distribute burdens and collectively address downwind impacts. Moreover, emission reductions from the iron and steel industry are not anticipated until 2026, long after a stay pending reconsideration will be completed. As a result, a stay pending reconsideration of the Good Neighbor Plan, and in particular the provisions of the Final Rule applicable to reheat furnaces and boilers at iron and steel mills, will have no impact on downwind attainment or maintenance of the NAAQS.

II. EPA Should Stay the Good Neighbor Plan Pending Judicial Review.

Under the APA, EPA may stay the effective date of the Good Neighbor Plan pending judicial review when "justice so requires." 5 U.S.C. §705. Multiple petitions have already been filed for judicial review, including petitions by Texas, Utah, Ohio, Indiana, West Virginia, and Oklahoma. More are likely, including a petition for judicial review that U. S. Steel is filing contemporaneously with this Petition. These cases are already spread across three circuits, and additional litigation may expand the number of courts further.

The effective date of the Final Rule is August 4, 2023, but the Good Neighbor Plan already cannot be applied in several states because of stays of the SIP Disapproval. A stay pending judicial review will therefore simply reflect the legal reality in those States. Further, the significant legal flaws in EPA's Final Rule discussed above make it likely that judicial review will result in a remand, if not vacatur, of the Good Neighbor Plan. As a result, a stay is strongly supported to avoid the unnecessary expenditure of EPA resources, State resources, and the resources of the public and regulated industries in addressing a FIP that is unlikely to sustained in its current form.

Further, while EPA is not bound to apply the same four-factor analysis used by courts for granting a judicial stay pending review, these factors also support issuance of a stay pending judicial review. Under this standard, the considerations for a stay are:

> 1. whether the stay applicant has made a strong showing that he is likely to succeed on the merits;
>
> 2. whether the applicant will be irreparably injured absent a stay;
>
> 3. whether issuance of the stay will substantially injure the other parties interested in the proceeding; and
>
> 4. where the public interest lies.

Nken v. Holder, 556 U.S. 418, 434, 129 S.Ct. 1749, 173 L.Ed.2d 550 (2009) (citation omitted). These "four considerations are factors to be balanced and not prerequisites to be met." *State of Ohio ex rel. Celebrezze v. Nuclear Regul. Comm'n*, 812 F.2d 288, 290 (6th Cir. 1987).

A. There is a High Likelihood of Success on the Merits.

There is no fixed probability of success the agency must find in applying these considerations. "Ordinarily the party seeking a stay must show a strong or substantial likelihood of success. However, at a minimum the movant must show 'serious questions going to the merits and irreparable harm which decidedly outweighs any potential harm to the defendant if a [stay] is issued.'" *Id.* (*quoting In re DeLorean Motor Company*, 755 F.2d 1223, 1229 (6th Cir.1985)).

As discussed above, the Good Neighbor Plan has substantive and procedural flaws, each of which individually, and more so when combined, demonstrate "a high probability of success on the merits." *Ohio ex rel. Celebrezze v. Nuclear Regul. Comm'n.*, 812 F.2d 288, 290 (6th Cir.1987). Substantively, EPA's Final Rule is based on circumstances that have been completely undermined by recent developments. It was not promulgated in accordance with the Clean Air Act. And was rushed to the point that it violates the core tenets of Cooperative Federalism on which the Clean Air Act, and the NAAQS program in particular, is based. For the iron and steel industry in particular, the FIP lacks a factual basis for supporting the regulation of reheat furnaces and boilers, or a justification for the requirements included in the Final Rule.

Because EPA's FIP is factually and procedurally flawed, and imposes requirements on reheat furnaces and boilers that are incomplete and in many states unenforceable, a challenge for judicial review is likely to prevail on the merits.

B. Absent a Stay, U. S. Steel Will Suffer Imminent Irreparable Harm.

Relevant factors for evaluating the harm which will occur both if the stay is issued and if it is not, the court must look to three factors: the substantiality of the injury alleged, the likelihood of its occurrence, and the adequacy of the proof provided. *Ohio ex re. Celebrezze*, 812 F.2d at 290 (*citing Cuomo v. United States Nuclear Regulatory Commission*, 772 F.2d 972, 974 (D.C.Cir.1985)).

The Final Rule poses substantial and imminent injuries to U. S. Steel. EPA itself warned owners and operators that they would need to "begin engineering and financial planning" as of the date of the *Proposed Rule* to be prepared to meet EPA's implementation timetable. Proposed Rule at 20,036; *see also* Unpublished Order, *Texas v. EPA*, Case No. 23-60069, ECF 269-1, at 22 (citing EPA's FIP timetable as ground for finding irreparable harm). Notwithstanding the fact that it is unreasonable to suggest that significant funds and resources should be used to implement a *proposed* rule that is subject to change (as the Good Neighbor Plan has changed), the Final Rule afforded no relief from this unreasonably short schedule. As discussed above, and in the attached Declaration of Alexis Piscitelli (Attachment A at ¶¶6-10), it allows insufficient time for design, permitting, and installation of controls; likely years less than what will be required. As a result, absent a stay, U. S. Steel cannot afford to wait before it must incur substantial costs on work plans that EPA does not have authority to impose, and on the design, permitting and installation of boiler and reheat furnace modifications that are unnecessary and may be subject to modification in a revised FIP.

As further discussed in the attached Declaration of Alexis Piscitelli, implementation of the Good Neighbor Plan is requiring U. S. Steel to incur immediate and significant costs. Attachment A at ¶¶3, 11-19. The work required by the Good Neighbor Plan will cost between $28 and $46 million at a single facility, excluding testing, monitoring, recordkeeping and reporting costs. Attachment A at ¶15. This cost far exceeds the $7,500/ton marginal cost assumed by EPA in the Final Rule. *See, e.g.* Final Rule at 36,733. These costs are not only unnecessary, they are being imposed without adherence to law. As a result, they constitute a significant irreparable harm to U. S. Steel. *See Thunder Basin Coal Co. v. Reich*, 510 U.S. 200, 220-21 (1994) ("complying with a regulation later held invalid almost always produces the irreparable harm of nonrecoverable compliance costs.") (Scalia, J., concurring in part and in the judgment). The compounding effect of these burdens on top of other regulations pending from EPA further exacerbates to significance of the harm to U. S. Steel. *See* Attachment A at ¶¶20-28.

C. A Stay Will Not Significantly Injury Other Parties.

Emissions reductions from the iron and steel industry are not anticipated to take effect until 2026 at the earlier in the Final Rule. As a result, there can be no appreciable injury to third parties pending judicial review. Moreover, because the Good Neighbor Plan cannot be applied in at least 10 states pending judicial review of EPA's SIP Disapproval, the Good Neighbor Plan is unlikely to apply until the 2024 ozone trading season even without a stay. As a result, a stay pending judicial review of the FIP will not result in any harm.

D. A Stay is in the Public Interest.

As courts have held, there is a public interest in enjoining inequitable conduct and in minimizing unnecessary costs to be met from public coffers. *See, e.g. B & D Land & Livestock Co. v. Conner*, 534 F. Supp. 2d 891, 910 (N.D. Iowa 2008). Here, the public interest supports a stay. As discussed above, EPA's Final Rule is without statutory authority and was promulgated through the inequitable exclusion of public participation on the information central to EPA's action. The result will be costly and needless public expenditures, both by U. S. Steel and the States that must act on the hundreds of permit applications the FIP requires, all while the Good Neighbor Plan is pending judicial review.

While it was an error for EPA to promulgate the Final Rule, EPA can ameliorate the harm of this error by staying the effect of the Good Neighbor Plan until the merits of the issues above can be fully evaluated and addressed.

Conclusion

Because circumstances arising after the close of the public comment period and before the time for judicial review demonstrate that the Good Neighbor Plan must be withdrawn, and because the FIP imposes significant obligations on the iron and steel industry that were not part of the Proposed Rule and that, with further comment, should have been corrected or amended, EPA is obligated to grant reconsideration and should withdraw the Final Rule, either in its entirely or as to reheat furnaces and boilers at iron and steel mills.

Further, to avoid the significant and irreparable harm to U. S. Steel arising from EPA's erroneous promulgation of the Final Rule, EPA should stay 40 CFR 52.43 of the Good Neighbor Plan and 40 CFR 52.45 as applied to the iron and steel industry pending reconsideration and pending judicial review.

Dated: August 4, 2023

Respectfully Submitted,

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ATTACHMENT A – DECLARATION OF ALEXIS PISCITELLI

Before the United States Environmental Protection Agency

In re: Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023)	) EPA Docket Nos. EPA–HQ–OAR–2021–0668 FRL–8670–02–OAR

Declaration of Alexis Piscitelli

I, Alexis Piscitelli, am over 18 years of age and make the following declaration pursuant to 28 U.S.C. § 1746:

1. I am the Senior Director Environmental for North American Flat Roll. at United States Steel Corporation ("U. S. Steel"), where I am responsible for ensuring compliance and reporting requirements are met in accordance with federal, state and local environmental permits and regulations. I have been employed by U. S. Steel for over 26 years and have advanced through various positions.

2. I am providing this declaration on behalf of U. S. Steel's Petition for Reconsideration and Stay of the United States Environmental Protection Agency's ("EPA's") Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards ("Good Neighbor Plan" or "Final Rule"), 88 Fed. Re. 36,654 (June 5, 2023).

3. As further explained in this declaration, the Final Rule will require immediate actions by U. S. Steel, including either curtailing the operation of reheat furnaces and boilers at U. S. Steel, or the expenditure of millions of

dollars to prepare now for implementation of the Good Neighbor Plan. Either or both of these actions will impose significant additional cost on U. S. Steel. Curtailing or the potential shutdown of the reheat furnaces would impact downstream units and ultimately customers. Curtailing the boilers will reduce electricity generation and increase the demand for outside purchased power, increasing costs and putting additional strain on the grid.

4. The Good Neighbor Plan also omits important flexibilities U. S. Steel uses to effectively and efficiently manage its environmental obligations.

5. This declaration is based on my personal knowledge of facts and information pertaining to U. S. Steel's business and the implications of EPA's Good Neighbor Plan. My knowledge is based on my history with U. S. Steel and analysis U. S. Steel has conducted of the Good Neighbor Plan.

I. The Implementation Schedule for the Good Neighbor Plan is Insufficient

6. In response to the Good Neighbor Plan, U. S. Steel developed a schedule for compliance with the regulatory obligations applicable to U. S. Steel – Gary Works' 84" Hot Strip Mill.

7. Based on our experience with projects of similar size and complexity, the assessment, design, permitting, and installation of low-NOx burners at all four furnaces will not be complete until May 2027, over a year beyond the May 2026 deadline for certification of completion of installation of low-

NOx technology in the Good Neighbor Plan. A copy of the project schedule is included as Appendix A to the attached Barr report (Attachment 1).

8. This schedule conservatively assumes that permitting can be completed in six months. Based on my experience, permitting can take significantly longer, leading to additional delays in completion.

9. U. S. Steel has also had difficulty obtaining vendor quotes for the required work. Consistent with U. S. Steel practice, our contractor, Barr, has attempted to obtain three separate vendor quotes for each technology U. S. Steel is analyzing. Only two firms provided full responses as of July 7, 2023. For one technology, selective non-catalytic reduction ("SNCR"), Barr contacted at least eight vendors but was able to obtain only two estimates. This further demonstrates the need for additional time for implementation of the Good Neighbor Plan, as we anticipate vendors will continue to experience backlogs and supply chain disruptions.

10. U. S. Steel has also had difficulty finding and scheduling qualified union contractors to work on significant projects at our facilities. For example, there are four reheat furnaces at Gary, each will require a significant outage to retrofit the equipment with low NOx burners or the equivalent. We anticipate the availability of qualified union workers will become even a

larger issue with multiple sources being impacted by the Good Neighbor Plan.

II. Implementation of the Good Neighbor Plan Requires U. S. Steel to Incur Immediate and Significant Costs

11. Among other things, the Good Neighbor Plan as promulgated imposes requirements on certain reheat furnaces at iron and steel mills, including the requirement to design a low-NOx burner or alternative low-NOx technology to achieve NOx emission reductions of at least 40% from baseline emission levels measured during performance testing that meets the criteria set forth in the rule. Additional obligations include emissions monitoring, recordkeeping, and reporting requirements.

12. While I agree that requiring a universal, hard limit for reheat furnaces is not appropriate, the requirement to design to meet a minimum 40% reduction of NOx from baseline is not appropriate because it does not take into account what is achievable for each reheat furnace, including what the baseline value actually is – whether, for example, it is 0.12 lb/MMBtu or 0.24 lb/MMBtu, what limits there are on the type of NOx reduction technology that can be used, what fuels the reheat furnace uses, what other pollution control technologies are already in place, or other factors that may make a minimum 40% reduction on some units technically or economically infeasible.

13. Baseline emission level performance testing cannot be completed without significant modification. For example, the reheat furnaces at Gary are very difficult to access. Testing equipment required to meet the USEPA specification cannot be used as currently configured. The facility will require engineered modification to provide access for personnel and equipment to conduct the required testing to establish a baseline for at least a 40% reduction design.

14. Based on the deadlines in the Good Neighbor Plan, which include submitting a completed work plan by August 5, 2024, U. S. Steel has already needed to begin project engineering and design and is already incurring significant costs to complete this work. Without a stay, and while the rule is subject to petitions for review, these costs are expected to substantially increase in the coming months with EPA's aggressive rule implementation schedule.

15. Based on an initial assessment of the costs supported by vendor quotes, I estimate installing low-NOx burners at the four reheat furnaces at U. S. Steel – Gary Works' 84" Hot Strip Mill will cost between approximately $28 million to more than $46 million. *See* Attachment 1 at Table 4-1. This does not include additional operating costs associated with the new equipment or

additional monitoring, performance testing, recordkeeping, and reporting costs associated with the Good Neighbor Plan.

16. This results in an estimated cost effectiveness of between $18,300 and $42,300 per ton NOx removed. Attachment 1 at Table 4-2. This far exceeds $3,656/ton average EPA includes in its Technical Memorandum to support the Final Rule. Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, EPA-HQ-OAR-2021-0668-0956, at Table 6 (March 15, 2023). It also far exceeds EPA's marginal cost threshold of $7,500/ton, the average cost-per-ton range for all non-EGUs of $939/ton to $14,595/ton, and even the $11,000/ton representative EGU retrofit cost EPA used for comparison in the Good Neighbor Plan. Final Rule at 36,746.

17. Without the Good Neighbor Plan, U. S. Steel would not need to incur these costs.

18. A stay of the FIP is necessary to avoid unnecessary costs until a final decision is reached on what obligations should apply to reheat furnaces and boilers at iron and steel mills.

19. Without a stay, U. S. Steel will incur significant and irreparable harm in reconfiguring the hot strip mill at Gary Works to allow for baseline performance testing and implementing the rule's requirements at the Company.

III. The Cumulative Burdens of the Good Neighbor Plan and Other Federal Requirements will Be Substantial and Could Have a Material Impact on Critical Infrastructure, National Security, and U. S. Steel Operations.

20. The U.S. steel industry is responsible for over $520 billion in economic output, supporting over 2 million jobs. It generates over $56 billion in tax revenues annually.

21. In a study conducted under Section 232 of the Trade Expansion Act of 1962 (19 U.S.C. §1862), the U.S. Department of Commerce determined that domestic steel production is essential for national security; and that domestic steel production depends on a healthy and competitive U.S. industry. (See https://www.bis.doc.gov/index.php/other-areas/office-of- technology-evaluation-ote/section-232-investigations).

22. The Cybersecurity & Infrastructure Security Agency has identified the iron and steel industry as a core critical infrastructure industry impacting transportation systems, electric power grid, water systems, and energy generation systems. (See https://www.cisa.gov/topics/critical-infrastructure-security-and-resilience/critical-infrastructure-sectors/critical-manufacturing-sector).

23. Implementation of the Final Rule upon the steel industry, when at the same time implementing new rules upon all facets of domestic steel

manufacturing also potentially jeopardizes thousands of good-paying USW jobs.

24. U. S. Steel is committed to continuing to work with federal partners to develop and implement scientifically sound regulations that effectively and demonstrably benefit the environment.

25. EPA's promulgation of overlapping Clean Air Act regulations without adequate consideration of their interaction undermines these efforts.

26. At the same time that EPA promulgated the Good Neighbor Plan, where it is mandating the installation of controls at reheat furnaces and boilers at iron and steel mills, EPA is proposing new MACT standards at taconite, integrated iron and steel facilities, and coke plants; as well as proposing revised NAAQS standards (e.g., PM2.5) which, combined, could have a material impact on the domestic steel industry, significantly affect the schedule for achieving these requirements, and result in a shortage of available technical support for implementation of these rules.

27. As noted above, U. S. Steel is already having difficulty obtaining qualified contractors and vendor quotes. These additional rules will exacerbate the problem.

28. EPA has also announced that it anticipates proposing reconsideration of the current ozone NAAQS in April 2024. As a result, EPA may be revising the

ozone NAAQS at the same time that the Good Neighbor Plan is requiring U. S. Steel to install pollution controls to address the current standards. Piecemealing these two rules, for which implementation will likely overlap, is problematic and inappropriate, as U. S. Steel could quite possibly be compelled to install additional or different controls on the same emission units following EPA's reconsideration. This would result in significant waste and could be avoided if EPA withdraws the Good Neighbor Plan and takes the two years allowed by the Clean Air Act for implementation of a revised FIP.

IV. Importance of Facility-Wide Averaging to U. S. Steel

29. U. S. Steel uses – and EPA, as well as other regulatory agencies, have allowed – emissions unit averaging where appropriate to effectively and efficiently satisfy regulatory obligations.

30. For example, at U. S. Steel – Great Lakes Work, boilers are permitted by boiler house, allowing averaging across multiple boilers serving the same or similar functions. At U. S. Steel – Granite City Works, Slab Furnace Nos 1-4 are subject to a single NOx limit, allowing averaging across all four reheat furnaces.

31. Allowing similar averaging in the Good Neighbor Plan would allow U. S. Steel to continue to benefit from the coordinated management of these emission units without sacrificing overall emissions performance.

V. Conclusion

32. In my opinion, the schedule set forth in the Good Neighbor Plan is not realistic and underestimates the time needed for compliance by at least a year. If emission units cannot achieve compliance by the scheduled deadlines and the deadlines are not stayed or extended, those emission units will be required to curtail operation. As a result. U. S. Steel is already required to incur substantial costs in order to prepare for the upcoming Good Neighbor Plan deadlines despite pending petitions for reconsideration and judicial review that may affect the applicability of the Good Neighbor Plan and the obligations that it imposes on reheat furnaces and boilers.

33. A stay of the Good Neighbor Plan will mitigate these harms.

I declare, under penalty of perjury, that the foregoing is true and correct. Executed on August 4, 2023.

Alexis Piscitelli
Sr. Director Environmental – NAFR
United States Steel Corporation

ATTACHMENT 1

Technical Memorandum

To: Louis Covelli (U. S. Steel)
From: Dane Jensen
Subject: 84" Hot Strip Mill Reheat Furnaces Good Neighbor Plan NO_X Emissions Controls Evaluation
Date: August 3, 2023
Project: 14451044.00
c: Thomas Ruffner, David Hacker, Kendra Jones, Christopher Hardin, Brett Tunno (U. S. Steel), Ryan Siats (Barr Engineering Co.)

Executive Summary

The U.S. Environmental Protection Agency (EPA) is taking action under the "good neighbor" or "interstate transport" provision of the Clean Air Act, with rulemaking that will take effect on August 4, 2023. The Good Neighbor Plan rulemaking under Docket ID No. EPA–HQ–OAR–2021-0668 requires emission reductions for affected facilities at U. S. Steel – Gary Works (USS), namely the 84" Hot Strip Mill (HSM) reheat furnaces (RHFs). The draft rulemaking requires a 40% NO_X reduction for RHFs. Barr was tasked with assessing the technical feasibility of selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) technologies, reviewing facility impacts of feasible NO_X controls including Low NO_X Burners (LNB), estimating costs and the cost effectiveness of feasible NO_X controls, and summarizing annual compliance testing costs.

The key findings of the HSM NO_X evaluation include:

- SCR is not technically feasible for the RHFs.
- SNCR is not technically feasible for the RHFs. There are operating conditions where the flue gas temperatures are expected to be outside the required SNCR reaction range.
- The compliance schedule in the draft rulemaking is insufficient to allow for installation of NO_X control technologies given requirements for baseline emissions testing, permitting, and availability of equipment vendors, mill wrights, engineering staff, etc.
- LNBs would require furnace upgrades, new flame safety equipment, and other facility modifications to accommodate this technology.
- The cost effectiveness of LNBs ranges from \$18,300 to \$42,300 per ton of NO_X removed.
- Annual performance testing costs for the RHFs are estimated to be \$13,300 to comply with the monitoring requirements of the Good Neighbor Plan.

Additional detail on each finding is summarized by Section below.

1 Good Neighbor Rule Regulatory Applicability

The regulatory applicability of the RHFs to the Good Neighbor Plan is described below.

40 CFR 52.43(b) states "*The requirements of this section apply to each new or existing reheat furnace at an iron and steel mill or ferroalloy manufacturing facility that directly emits or has the potential to emit 100 tons per year or more of NO_X on or after August 4, 2023, does not have low-NO_X burners installed, and is located within any of the States listed in § 52.40(c)(2), including Indian country located within the borders of any such State(s).*" The four reheat furnaces located at the Gary Works HSM all exceed a 100 tpy NO_X potential to emit, are in a state listed in §52.40(c)(2), and do not have LNB installed. Therefore, the RHFs are subject to the provisions of 40 CFR 52.43 and must achieve a 40% NO_X reduction from baseline conditions by the 2026 ozone season.

2 Technical Feasibility of SNCR and SCR

The technical feasibility of SNCR and SCR for the RHFs is discussed below. Figure 1 marks locations #1, #2, and #3 that will be referred to in the SNCR and SCR feasibility discussions for reference.

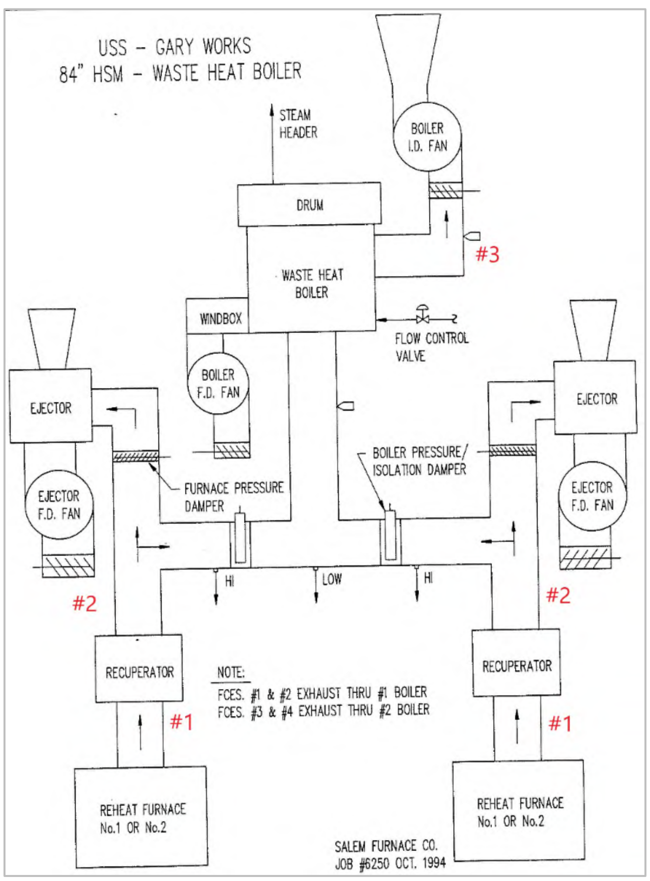

Figure 1 SNCR and SCR Feasibility Evaluation Locations

2.1 SNCR

SNCR involves the injection of ammonia or urea into a flue gas stream where the reagents react with NO_X to form elemental nitrogen. SNCR reactions require the flue gas temperature to be within a 1,600° Fahrenheit (F) to 2,100°F temperature range, with 1,800°F being ideal.

The only suitable SNCR injection location within the appropriate temperature location is #1, namely the outlet of the RHFs prior to the recuperator (refer to Figure 1). USS provided temperature data for this location and typically temperatures range from 1,600 to 1,930°F when operating. However, there are concerns about the viability of the data. A large portion of the data Barr received shows failed thermocouples or unreliable data trends. Figure 2 and Figure 3 show the Furnace 1 East and Furnace 4 East uptake temperatures, respectively, as an example of the sporadic data. It is unclear what represents "real" data vs. what is noise or failed thermocouples.

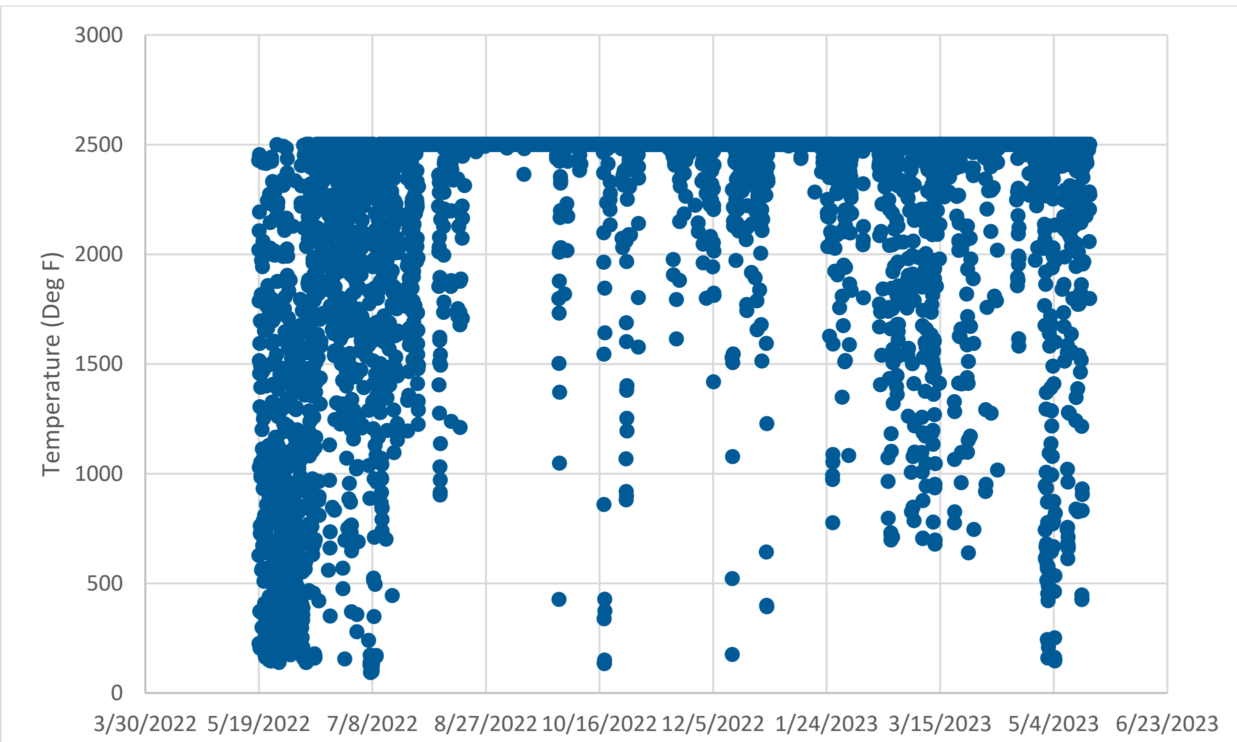

Figure 2 Furnace 1 East Uptake Temperatures Vs. Time

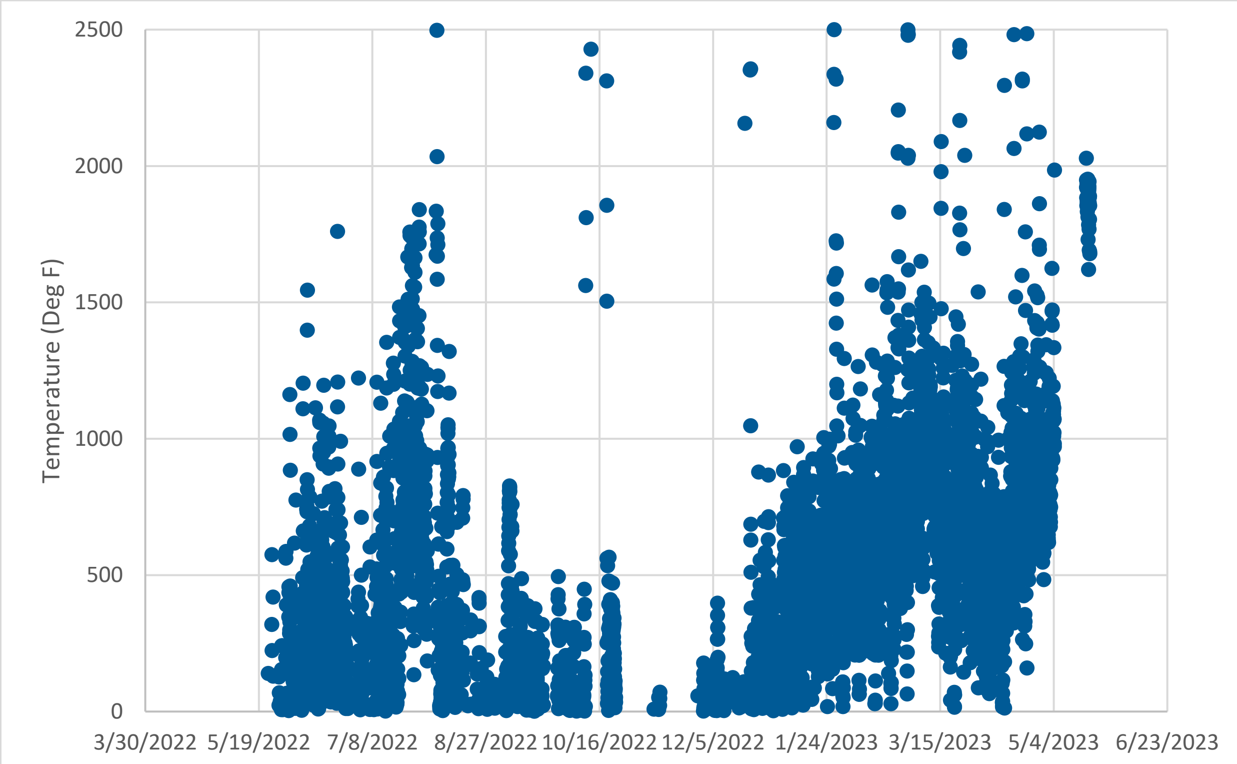

Figure 3 Furnace 4 East Uptake Temperatures Vs. Time

Another important design factor is residence time in the ducting with the high SNCR reaction temperatures. Vendors believe that there should be sufficient residence for SNCR in this application based on their review of USS data.

However, there are operating conditions where the flue gas fails to meet the minimum SNCR reaction temperatures, rendering SNCR infeasible. The Good Neighbor Plan requires a 40% NO_X reduction. Therefore, SNCR cannot sufficiently control NO_X at all times under all operating conditions. This is especially important during hot-standby conditions where fuel firing occurs, but USS expects the uptake temperatures to be below minimum SNCR requirements. In addition, a vendor stated that a feasibility study would be required to provide any sort of NO_X reduction guarantee. While SNCR is feasible during some operating scenarios, it cannot provide the needed consistent NO_X reduction for compliance purposes.

2.2 SCR

SCR reduces NO_X emissions with ammonia or urea injection in the presence of a catalyst. The catalyst enables the de- NO_X reactions to proceed at a lower temperature than SNCR. Most SCR catalysts must be at 450° F to 800° F for proper SCR operation based on vendor discussion and the EPA Control Cost Manual[1]. Each location for SCR from Figure 1 above was reviewed for SCR feasibility.

Location #1 – the temperatures at location #1 are too high (i.e., 1,600 to 1,930°F), so SCR is not technically feasible.

Location #2 – Waste heat temperatures exiting the recuperator are also too high for SCR. From May 2022 to May 2023, the average waste heat temperature was over 900°F, with temperature spikes exceeding 1,150°F. This is well above the optimal SCR range noted above. USS is aware that there are high-temperature applications of SCR on simple cycle combustion turbines in the temperature ranges of 850 to 1,000°F with vendors stating that 1,100°F would be the absolute maximum allowable temperature. However, high temperature SCR systems are significantly more costly due to special catalyst formulations and the catalyst life expectancy tends to shorten significantly, requiring more frequent changes that may inhibit production. As noted above, the high temperature spikes above 1,150°F would be above the maximum allowable temperature range making SCR infeasible for this location. In addition, high temperature SCR applications for simple cycle combustion turbines often use tempering air to reduce exhaust temperatures to suitable levels for normal SCR reaction temperatures. However, the use of tempering air is impractical for this application because the exhaust flows exiting the recuperator are quite large (i.e., more than 800,000 acfm) meaning that large amounts of make-up air would be required to sufficiently cool the exhaust flow to acceptable SCR reaction temperatures. The exhaust handling equipment cannot accommodate additional flow, and all the areas surrounding the recuperator outlet ductwork are extremely cramped with no reasonable way to incorporate additional cooling air, let alone provide sufficient residence time for mixing. In addition, tempering air would dilute the NO_X inlet concentration reducing the control equipment effectiveness. Further, SCR reactors for airflows of this magnitude are very large requiring a significant footprint. As noted above, the spacing surrounding this location is cramped, and it would be essentially impossible to shoe-horn a SCR reactor in place for this application. Also, it is not known if the existing building infrastructure could support additional weight above the furnace after the recuperator. Therefore, SCR is not technically feasible for location #2.

Location #3 – Exhaust temperatures at the exit of the waste heat boilers (WHBs) range from approximately 450 – 925°F. This mostly fits the SCR reaction temperature requirements. While the temperature profile may be satisfactory, it is impractical to install a SCR reactor at this location. Only a portion of the RHF exhaust is routed through the WHBs, meaning that the entire gas stream would not be treated. In addition, there are times when only the ejector stack is used, and no exhaust is routed through the WHBs. Therefore, there is no way to guarantee any consistent level of NO_X reduction with SCR at this location with incomplete or no RHF exhaust treatment, and would jeopardize compliance with the Good Neighbor Plan limits. Further, the variable exhaust flow through the WHBs would significantly complicate any SCR reactor design and may make it difficult to properly inject sufficient reagents and maintain proper mixing for all operating conditions. Further, spaces surrounding the outlet of the WHBs are very

[1] https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

cramped leaving no viable location for a sizeable SCR reactor. Therefore, SCR is not practical or technically feasible for Location #3.

3 Facility Impacts of New NO_X Controls

According to discussions with vendors, LNBs will not impact production rates and burner vendors are willing to provide this guarantee. While not inherently challenging to LNBs, there are significant concerns about the schedule and the implementation period proposed in the Good Neighbor Plan (i.e., reductions must be achieved by the 2026 ozone season). As a result of this rulemaking, USS will need to conduct and obtain results from baseline emissions testing prior to submission of an application to modify the facility's operating permit to integrate either control technology. In addition, there are numerous facilities and industries nationwide that will be required to install controls for compliance. Therefore, USS is concerned that there will be insufficient resources for performance testing, permitting, engineering, equipment suppliers, equipment fabricators, and mill wrights that will allow USS to install necessary controls for compliance, much less all other affected facilities nationwide.

Schedule concerns have been evident during the development of this memo as Barr has attempted to obtain three separate vendor quotes. However, only two firms have provided costs for both LNB August 3, 2023. One LNB vendor failed to provide a quotation to USS even after stating that they could provide a new quote, so a 2020 cost estimate was scaled to 2023 dollars for this effort. This further demonstrates the need for additional time for implementation of this rule given vendor backlogs and unexpected supply chain disruptions. In addition, USS estimated a schedule based on engineering experience for the installation of LNBs (included as Appendix A to this memo) showing that there is insufficient time in the draft rule to install controls on all four RHFs and meet the compliance deadline.

Facility impacts for LNB installations are listed below:

- To accommodate new burners, USS will need to upgrade the furnace so that sufficient pressure can be maintained at the burners for safe and reliable operation.
- New National Fire Protection Association combustion safety equipment will be installed with new burners.
- Fuel pressure regulators will require modifications to increase fuel pressure at the burners.
- Some burner vendors require new combustion air fans complicating the overall design and installation.

4 Cost Estimates of New NO_X Controls

Barr and USS evaluated the costs for LNBs below for the RHFs. A detailed breakdown of capital equipment and installation costs has been prepared by USS for LNB based on vendor quotes and engineering experience. Table 4-1 summarizes capital costs for all furnaces for each vendor.

Table 4-1 Total Capital Investment Summary for LNB by Vendor (Total Cost for All Four Furnaces)

Vendor	Total HSM Capital Investment ($)
Vendor 1	$28,400,000
Vendor 2	$32,300,000
Vendor 3 (2020 Scaled Estimate)	$46,400,000

Detailed cost-effectiveness calculations for LNB are included in Appendix B. Table 4-2 summarizes the control costs for each LNB vendor.

Table 4-2 NO_X Control Cost Summary for LNB Vendors (Individual Furnace Cost)

Vendor	Total Capital Cost ($)	Annualized Cost ($/yr)	NO_X Reduction (tpy)	Cost Effectiveness ($/ton NO_X Removed)
Vendor 1	$7,112,000	$1,156,000	63	$18,300
Vendor 2	$8,073,000	$1,294,000	31	$42,300
Vendor 3 (2020 Estimate)	$11,590,000	$1,800,000	61	$29,500

5 Annual Performance Testing Cost Estimate

USS sought a performance testing bid for annual reheat furnace testing. The annual RHF performance testing costs are estimated to be $13,322. These costs and other miscellaneous costs such as recordkeeping and reported are not included in the cost-effectiveness evaluation in Appendix B.

6 Conclusions and Recommendations

The key findings of the HSM NO_X evaluation include:

- SCR is not technically feasible for the RHFs.
- SNCR is not technically feasible for the RHFs. There are operating conditions where the flue gas temperatures are expected to be outside the required SNCR reaction range.
- The compliance schedule in the draft rulemaking is insufficient to allow for installation of NO_X control technologies given requirements for baseline emissions testing, permitting, and availability of equipment vendors, mill wrights, engineering staff, etc.
- LNBs would require furnace upgrades, new flame safety equipment, and other facility modifications to accommodate this technology.
- The cost effectiveness of LNBs ranges from $18,300 to $42,300 per ton of NO_X removed.
- Annual performance testing costs for the RHFs is estimated to be $13,300 to comply with monitoring requirements of the Good Neighbor Plan.

Appendices

Appendix A

Estimated Low NOX Burner Installation Schedule

USS Gary Works - 84" HSM NOx Controls Evaluation
Appendix A - Estimated Low NOx Burner Installation Schedule

	-11	-10	-9	-8	-7	-6	-5	-4	-3	-2	-1	0	1	2	3	4	5
	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
Complete PAEE Paperwork																	
PAEE Approved																	
Engineering for emissions sampling infrastructure																	
Partial install of emissions sampling infrastructure to allow baseline testing (scaffolding, umbilical piping)																	
Air Permit Application Preparations																	
Baseline test complete																	
Obtain Air Permit - Permitting, Public Hearings, etc.																	
Perform detailed furnace study																	
Complete detailed design of burners																	
Complete burner installation scope and specification																	
Burner installation bids - price for each furnace separately																	
Complete AR Paperwork																	
AR Approved																	
Completion of emissions sampling infrastructure (permanent platforms, ladders, etc.)																	
Order for furnaces 1-4 burners placed																	
Procure materials for burners																	
Fabrication of burners furnace 1																	
Shipment of burners for furnace 1																	
Place burner installation PO for furnace 1																	
Furnace 1 mobilization material procurement																	
Furnace 1 Outage																	
Furnace 1 Performance Testing																	
Lessons Learned Furnace 1 - installation specification updated																	
Fabrication of burners furnace 2																	
Shipment of burners for furnace 2																	
Place burner installation PO for furnace 2																	
Furnace 2 mobilization material procurement																	
Furnace 2 Outage																	
Furnace 2 Performance Testing																	
Lessons Learned Furnace 2 - installation specification updated																	
Fabrication of burners furnace 3																	
Shipment of burners for furnace 3																	
Place burner installation PO for furnace 3																	
Furnace 3 mobilization material procurement																	
Furnace 3 Outage																	
Furnace 3 Performance Testing																	
Lessons Learned Furnace 3 - installation specification updated																	
Fabrication of burners furnace 4																	
Shipment of burners for furnace 4																	
Place burner installation PO for furnace 4																	
Furnace 4 mobilization material procurement																	
Furnace 4 Outage																	
Furnace 4 Performance Testing																	

USS Gary Works - 84" HSM NOx Controls Evaluation
Appendix A - Estimated Low NOx Burner Installation Schedule

	6	7	8	9	10	11	12	13	14	15	16	17
	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
Complete PAEE Paperwork												
PAEE Approved												
Engineering for emissions sampling infrastructure												
Partial install of emissions sampling infrastructure to allow baseline testing (scaffolding, umbilical piping)												
Air Permit Application Preparations												
Baseline test complete												
Obtain Air Permit - Permitting, Public Hearings, etc.												
Perform detailed furnace study												
Complete detailed design of burners												
Complete burner installation scope and specification												
Burner installation bids - price for each furnace separately												
Complete AR Paperwork												
AR Approved												
Completion of emissions sampling infrastructure (permanent platforms, ladders, etc.)												
Order for furnaces 1-4 burners placed												
Procure materials for burners												
Fabrication of burners furnace 1												
Shipment of burners for furnace 1												
Place burner installation PO for furnace 1												
Furnace 1 mobilization material procurement												
Furnace 1 Outage												
Furnace 1 Performance Testing												
Lessons Learned Furnace 1 - installation specification updated												
Fabrication of burners furnace 2												
Shipment of burners for furnace 2												
Place burner installation PO for furnace 2												
Furnace 2 mobilization material procurement												
Furnace 2 Outage												
Furnace 2 Performance Testing												
Lessons Learned Furnace 2 - installation specification updated												
Fabrication of burners furnace 3												
Shipment of burners for furnace 3												
Place burner installation PO for furnace 3												
Furnace 3 mobilization material procurement												
Furnace 3 Outage												
Furnace 3 Performance Testing												
Lessons Learned Furnace 3 - installation specification updated												
Fabrication of burners furnace 4												
Shipment of burners for furnace 4												
Place burner installation PO for furnace 4												
Furnace 4 mobilization material procurement												
Furnace 4 Outage												
Furnace 4 Performance Testing												

USS Gary Works - 84" HSM NOx Controls Evaluation
Appendix A - Estimated Low NOx Burner Installation Schedule

	18	19	20	21	22	23	24	25	26	27	28	29
	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26
Complete PAEE Paperwork												
PAEE Approved												
Engineering for emissions sampling infrastructure												
Partial install of emissions sampling infrastructure to allow baseline testing (scaffolding, umbilical piping)												
Air Permit Application Preparations												
Baseline test complete												
Obtain Air Permit - Permitting, Public Hearings, etc.												
Perform detailed furnace study												
Complete detailed design of burners												
Complete burner installation scope and specification												
Burner installation bids - price for each furnace separately												
Complete AR Paperwork												
AR Approved												
Completion of emissions sampling infrastructure (permanent platforms, ladders, etc.)												
Order for furnaces 1-4 burners placed												
Procure materials for burners												
Fabrication of burners furnace 1												
Shipment of burners for furnace 1												
Place burner installation PO for furnace 1												
Furnace 1 mobilization material procurement												
Furnace 1 Outage												
Furnace 1 Performance Testing												
Lessons Learned Furnace 1 - installation specification updated												
Fabrication of burners furnace 2												
Shipment of burners for furnace 2												
Place burner installation PO for furnace 2												
Furnace 2 mobilization material procurement												
Furnace 2 Outage												
Furnace 2 Performance Testing												
Lessons Learned Furnace 2 - installation specification updated												
Fabrication of burners furnace 3												
Shipment of burners for furnace 3												
Place burner installation PO for furnace 3												
Furnace 3 mobilization material procurement												
Furnace 3 Outage												
Furnace 3 Performance Testing												
Lessons Learned Furnace 3 - installation specification updated												
Fabrication of burners furnace 4												
Shipment of burners for furnace 4												
Place burner installation PO for furnace 4												
Furnace 4 mobilization material procurement												
Furnace 4 Outage												
Furnace 4 Performance Testing												

USS Gary Works - 84" HSM NOx Controls Evaluation
Appendix A - Estimated Low NOx Burner Installation Schedule

	30	31	32	33	34	36	36	37	38	39	40	41
	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
Complete PAEE Paperwork												
PAEE Approved												
Engineering for emissions sampling infrastructure												
Partial install of emissions sampling infrastructure to allow baseline testing (scaffolding, umbilical piping)												
Air Permit Application Preparations												
Baseline test complete												
Obtain Air Permit - Permitting, Public Hearings, etc.												
Perform detailed furnace study												
Complete detailed design of burners												
Complete burner installation scope and specification												
Burner installation bids - price for each furnace separately												
Complete AR Paperwork												
AR Approved												
Completion of emissions sampling infrastructure (permanent platforms, ladders, etc.)												
Order for furnaces 1-4 burners placed												
Procure materials for burners												
Fabrication of burners furnace 1												
Shipment of burners for furnace 1												
Place burner installation PO for furnace 1												
Furnace 1 mobilization material procurement												
Furnace 1 Outage												
Furnace 1 Performance Testing												
Lessons Learned Furnace 1 - installation specification updated												
Fabrication of burners furnace 2												
Shipment of burners for furnace 2												
Place burner installation PO for furnace 2												
Furnace 2 mobilization material procurement												
Furnace 2 Outage												
Furnace 2 Performance Testing												
Lessons Learned Furnace 2 - installation specification updated												
Fabrication of burners furnace 3												
Shipment of burners for furnace 3												
Place burner installation PO for furnace 3												
Furnace 3 mobilization material procurement												
Furnace 3 Outage												
Furnace 3 Performance Testing												
Lessons Learned Furnace 3 - installation specification updated												
Fabrication of burners furnace 4												
Shipment of burners for furnace 4												
Place burner installation PO for furnace 4												
Furnace 4 mobilization material procurement												
Furnace 4 Outage												
Furnace 4 Performance Testing												

Appendix B

RHF LNB Control Costs

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - Cost Summary
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

NO_x Control Cost Summary (emissions and costs are for each furnace individually)

Control Technology	Control Eff %[a]	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton
Low NOx Burners (LNB) - Vendor 1	41%	89.6	63.1	$7,111,695	$1,155,629	$18,301
Low NOx Burners (LNB) - Vendor 2	20%	122.2	30.6	$8,072,695	$1,293,776	$42,343
Low NOx Burners (LNB) - Vendor 3	40%	91.7	61.1	$11,593,945	$1,799,972	$29,455

a - Calculated control efficiencies are not based on EPA certified performance test methods due to lack of access to appropriate test locations. Therefore, the control efficiencies may not appropriately represent what can be achieved from existing baseline conditions and the required reductions in the Good Neighbor Plan may not be feasible.

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - Utility and Chemical Supply Costs
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Note: emissions and costs are for each furnace individually **Study Year** 2023

2023

Item	Unit Cost	Units	Cost	Year	Data Source
Operating Labor	74	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet
Maintenance Labor	74	$/hr			Assumed to be equivalent to operating labor
Other					
Sales Tax	7%			2020	Indiana sales tax rate
Interest Rate	8.25%			2023	Current prime bank rate
Operating Information					
Ozone Season Operating Hours	3,395	Hours			May 1st - September 30, adjusted for USS planned weekly maintenance outages
Annual Op. Hrs	8,100	Hours			USS Estimate
Utilization Rate	100%				Assumed
Design Capacity	600	MMBTU/hr			Permit listed duty
Equipment Life	20	yrs			Assumed
Plant Elevation	607	Feet above sea level			Plant elevation
	Baseline Emissions				
Pollutant	**Ton/Year**				
Nitrous Oxides (NOx)	152.8				Calculated
Baseline NOx performance	0.15	lb/MMBtu			Average of performance testing data
LNB NO_x Performance - Vendor 1	0.09	lb/MMBtu			Vendor guaranteed performance at 800F air preheat
Control efficiency - Vendor 1	41%				Calculated
LNB NO_x Performance - Vendor 2	0.12	lb/MMBtu			Vendor guaranteed performance at 800F air preheat
Control efficiency - Vendor 2	20%				Calculated
LNB NO_x Performance - Vendor 3	0.09	lb/MMBtu			2020 Quote LHV basis
Control efficiency - Vendor 3	40%				Calculated

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 1
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Note: emissions and costs are for each furnace individually

Desgin Capacity	600	MMBtu/hr
Expected Utiliztion Rate	100%	
Expected Ozone Season Operating Hours	3,395	Hours
Annual Interest Rate	8.3%	
Expected Equipment Life	20	yrs

CONTROL EQUIPMENT COSTS

Capital Costs							
Total Capital Investment (TCI) = DC + IC							**7,111,695**
Operating Costs							
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.					83,307
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost					1,072,321
Total Annual Cost (Annualized Capital Cost + Operating Cost)							**1,155,629**

EMISSION CONTROL COST EFFECTIVENESS

Pollutant	**Baseline Emis. T/yr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10				-	NA
Total Particulates				-	NA
Nitrous Oxides (NOx)	152.8	0.09	89.6	63.1	18,301
Sulfur Dioxide (SO_2)				-	NA

Notes & Assumptions

1 Refer to the *Vendor Summary* tab for Details
2 Assumed 0.1 and 0.5 hr/shift respectively for operator and maintenance labor
3 Controlled emission factor based on vendor estimated burner performance

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 1
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

CAPITAL COSTS				
Direct Capital Costs				
Equipment		Refer to *Vendor Summary* tab for Details	$	2,229,625
Installation		Refer to *Vendor Summary* tab for Details	$	1,494,250
Engineering		Refer to *Vendor Summary* tab for Details	$	304,320
Start-up and Commissioning		Refer to *Vendor Summary* tab for Details	$	381,000
Capital Spares		Refer to *Vendor Summary* tab for Details	$	137,500
Non-Capital Spares		Refer to *Vendor Summary* tab for Details	$	90,000
Cost Work		Refer to *Vendor Summary* tab for Details	$	2,475,000
Total Capital Investment (TCI) = DC + IC			**$**	**7,111,695**
OPERATING COSTS				
Direct Annual Operating Costs, DC				
Operating Labor				
Operator	73.79	$/Hr, 0.1 hr/8 hr shift, 8100 hr/yr		7,471
Supervisor	15%	15% of Operator Costs		1,121
Maintenance (2)				
Maintenance Labor	73.79	$/Hr, 0.5 hr/8 hr shift, 8100 hr/yr		37,357
Maintenance Materials	100%	of maintenance labor costs		37,357
Utilities, Supplies, Replacements & Waste Management				
NA	NA			-
NA	NA			-
Total Annual Direct Operating Costs				**83,307**
Indirect Operating Costs				
Overhead	60%	of total labor and material costs		49,984
Administration (2% total capital costs)	2%	of total capital costs (TCI)		142,234
Property tax (1% total capital costs)	1%	of total capital costs (TCI)		71,117
Insurance (1% total capital costs)	1%	of total capital costs (TCI)		71,117
Capital Recovery	10%	for a 20- year equipment life and a 8.25% interest rate		737,869
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost		**1,072,321**
Total Annual Cost (Annualized Capital Cost + Operating Cost)				**1,155,629**

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 1
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Capital Recovery Factors		
Primary Installation		
Interest Rate	8.25%	
Equipment Life	20	years
CRF	0.1038	

Operating Cost Calculations			**Annual hours of operation:**			8,100	
			Utilization Rate:			100%	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	73.79	$/Hr	0.1	hr/8 hr shift	101	7,471	$/Hr, 0.1 hr/8 hr shift, 8100 hr/yr
Supervisor	15%	of Op.			NA	1,121	15% of Operator Costs
Maintenance							
Maint Labor	73.79	$/Hr	0.5	hr/8 hr shift	506	37,357	$/Hr, 0.5 hr/8 hr shift, 8100 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	37,357	100% of Maintenance Labor

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 2
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Note: emissions and costs are for each furnace individually

Desgin Capacity	600	MMBtu/hr
Expected Utiliztion Rate	100%	
Expected Ozone Season Operating Hours	3,395	Hours
Annual Interest Rate	8.3%	
Expected Equipment Life	20	yrs

CONTROL EQUIPMENT COSTS

Capital Costs							
Total Capital Investment (TCI) = DC + IC							**8,072,695**
Operating Costs							
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.					83,307
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost					1,210,469
Total Annual Cost (Annualized Capital Cost + Operating Cost)							**1,293,776**

EMISSION CONTROL COST EFFECTIVENESS

Pollutant	**Baseline Emis. T/yr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10				-	NA
Total Particulates				-	NA
Nitrous Oxides (NOx)	152.8	0.12	122.2	30.6	42,343
Sulfur Dioxide (SO_2)				-	NA

Notes & Assumptions

1. Refer to the *Vendor Summary* tab for Details
2. Assumed 0.1 and 0.5 hr/shift respectively for operator and maintenance labor
3. Controlled emission factor based on vendor estimated burner performance

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 2
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

CAPITAL COSTS			
Direct Capital Costs			
Equipment		Refer to *Vendor Summary* tab for Details	$ 3,100,000
Installation		Refer to *Vendor Summary* tab for Details	$ 1,629,250
Engineering		Refer to *Vendor Summary* tab for Details	$ 288,945
Start-up and Commissioning		Refer to *Vendor Summary* tab for Details	$ 309,500
Capital Spares		Refer to *Vendor Summary* tab for Details	$ 180,000
Non-Capital Spares		Refer to *Vendor Summary* tab for Details	$ 90,000
Cost Work		Refer to *Vendor Summary* tab for Details	$ 2,475,000
Total Capital Investment (TCI) = DC + IC			**$ 8,072,695**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	73.79	$/Hr, 0.1 hr/8 hr shift, 8100 hr/yr	7,471
Supervisor	15%	15% of Operator Costs	1,121
Maintenance (2)			
Maintenance Labor	73.79	$/Hr, 0.5 hr/8 hr shift, 8100 hr/yr	37,357
Maintenance Materials	100%	of maintenance labor costs	37,357
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**83,307**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	49,984
Administration (2% total capital costs)	2%	of total capital costs (TCI)	161,454
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	80,727
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	80,727
Capital Recovery	10%	for a 20- year equipment life and a 8.25% interest rate	837,577
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,210,469**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,293,776**

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 2
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Capital Recovery Factors		
Primary Installation		
Interest Rate	8.25%	
Equipment Life	20	years
CRF	0.1038	

Operating Cost Calculations			**Annual hours of operation:**			**8,100**	
			Utilization Rate:			**100%**	
	Unit	**Unit of**	**Use**	**Unit of**	**Annual**	**Annual**	**Comments**
Item	**Cost $**	**Measure**	**Rate**	**Measure**	**Use***	**Cost**	
Operating Labor							
Op Labor	73.79	$/Hr	0.1	hr/8 hr shift	101	7,471	$/Hr, 0.1 hr/8 hr shift, 8100 hr/yr
Supervisor	15%	of Op.			NA	1,121	15% of Operator Costs
Maintenance							
Maint Labor	73.79	$/Hr	0.5	hr/8 hr shift	506	37,357	$/Hr, 0.5 hr/8 hr shift, 8100 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	37,357	100% of Maintenance Labor

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 3
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Note: emissions and costs are for each furnace individually

Desgin Capacity	600	MMBtu/hr
Expected Utiliztion Rate	100%	
Expected Ozone Season Operating Hours	3,395	Hours
Annual Interest Rate	8.3%	
Expected Equipment Life	20	yrs

CONTROL EQUIPMENT COSTS

Capital Costs							
Total Capital Investment (TCI) = DC + IC							**11,593,945**
Operating Costs							
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.					83,307
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost					1,716,665
Total Annual Cost (Annualized Capital Cost + Operating Cost)							**1,799,972**

EMISSION CONTROL COST EFFECTIVENESS

Pollutant	**Baseline Emis. T/yr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10				-	NA
Total Particulates				-	NA
Nitrous Oxides (NOx)	152.8	0.09	91.7	61.1	29,455
Sulfur Dioxide (SO_2)				-	NA

Notes & Assumptions

1. Refer to the *Vendor Summary* tab for Details
2. Assumed 0.1 and 0.5 hr/shift respectively for operator and maintenance labor
3. Controlled emission factor based on vendor estimated burner performance

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 3
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

CAPITAL COSTS			
Direct Capital Costs			
Equipment	Refer to *Vendor Summary* tab for Details	$	6,650,000
Installation	Refer to *Vendor Summary* tab for Details	$	1,838,000
Engineering	Refer to *Vendor Summary* tab for Details	$	243,945
Start-up and Commissioning	Refer to *Vendor Summary* tab for Details	$	147,000
Capital Spares	Refer to *Vendor Summary* tab for Details	$	150,000
Non-Capital Spares	Refer to *Vendor Summary* tab for Details	$	90,000
Cost Work	Refer to *Vendor Summary* tab for Details	$	2,475,000
Total Capital Investment (TCI) = DC + IC		**$**	**11,593,945**

OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	73.79	$/Hr, 0.1 hr/8 hr shift, 8100 hr/yr	7,471
Supervisor	15%	15% of Operator Costs	1,121
Maintenance (2)			
Maintenance Labor	73.79	$/Hr, 0.5 hr/8 hr shift, 8100 hr/yr	37,357
Maintenance Materials	100%	of maintenance labor costs	37,357
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**83,307**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	49,984
Administration (2% total capital costs)	2%	of total capital costs (TCI)	231,879
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	115,939
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	115,939
Capital Recovery	10%	for a 20- year equipment life and a 8.25% interest rate	1,202,923
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,716,665**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,799,972**

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 3
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Capital Recovery Factors		
Primary Installation		
Interest Rate	8.25%	
Equipment Life	20	years
CRF	0.1038	

Operating Cost Calculations			**Annual hours of operation:**			**8,100**	
			Utilization Rate:			**100%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	73.79	$/Hr	0.1	hr/8 hr shift	101	7,471	$/Hr, 0.1 hr/8 hr shift, 8100 hr/yr
Supervisor	15%	of Op.			NA	1,121	15% of Operator Costs
Maintenance							
Maint Labor	73.79	$/Hr	0.5	hr/8 hr shift	506	37,357	$/Hr, 0.5 hr/8 hr shift, 8100 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	37,357	100% of Maintenance Labor

USS Gary - HSM NOx Controls Evaluation
Appendix B - Low NOx Burner Cost Estimates (All Furnaces)
Vendor 1 Estimate

Burners	Ultra-Low Nox Burners
New burners will fit inside existing bodies (plug & play)

Flame safety included:
- Covert the soak zone to a supervised system to bring the soak zone above auto-ignition
- 16 New Soak Burners, Direct Spark Ignition, Flame Rod, Transformer, Ignition Cable, Necessary Gas and Air Valves
- Double Block Valves for 40 Soak Burners
- New NFPA Compliant Main Fuel Train
- New NFPA Compliant Pilot Train - Required for Cold Start Operation in Bottom Heat.
- To Accommodate Flame Supervision in the Soak Section and Cold Start Capabilities in the Bottom Heat Section.

Included in cost scope:
- Upgrades to combustion air system and recuperators
- NG piping replacement as required - restricted piping... coke oven gas remediations
- Upgrades to Level 0/1 components
- Refractory

Task	Item	Vendor	Estimate	Contingency		Amount
1000	**Equipment**					**$ 8,918,500**
	Burners	VENDOR 1	$ 7,320,000	5%	$ 366,000	$ 7,686,000
	Emissions Sampling/Testing Infrastructure		$ 400,000	20%	$ 80,000	$ 480,000
	Peripheral Control Equipment		$ 200,000	20%	$ 40,000	$ 240,000
	Refractory/Piping Materials		$ 300,000	20%	$ 60,000	$ 360,000
					$ 152,500	$ 152,500
1100	**Installation**					**$ 5,977,000**
	Burners		$ 3,800,000	20%	$ 760,000	$ 4,560,000
	Emissions Sampling/Testing Infrastructure		$ 850,000	30%	$ 255,000	$ 1,105,000
	Model/Pie Updates		$ 90,000	30%	$ 27,000	$ 117,000
	Level 1 Updates		$ 150,000	30%	$ 45,000	$ 195,000
2900	**Engineering**					**$ 1,217,280**
	Impact Analysis and Study		$ 53,600	5%	$ 2,680	$ 56,280
	Technical Support for Impact Study		$ 20,000	5%	$ 1,000	$ 21,000
	Detailed Furnace Study	VENDOR 1	$ 230,000	5%	$ 11,500	$ 241,500
	Design of Emissions Sampling/Testing Infrastructure		$ 150,000	20%	$ 30,000	$ 180,000
	Installation Specification Development		$ 150,000	20%	$ 30,000	$ 180,000
	Constructability		$ 60,000	20%	$ 12,000	$ 72,000
	Furnace Model Modifications	VENDOR 1	$ 60,000	20%	$ 12,000	$ 72,000
	Level I Design - Burners/Flame Safety/Consulting		$ 90,000	20%	$ 18,000	$ 108,000
	As-Built Drawings - MOC		$ 160,000	20%	$ 32,000	$ 192,000
	Drawing Management		$ 90,000	5%	$ 4,500	$ 94,500
2910	**Start-up and Commissioning**					**$ 1,524,000**
	Field Supervision	VENDOR 1	$ 780,000	20%	$ 156,000	$ 936,000
	Scheduling and Cost Control		$ 90,000	20%	$ 18,000	$ 108,000
	Construction Management		$ 400,000	20%	$ 80,000	$ 480,000
3000	**Capital Spares (>$10,000)**					**$ 550,000**
	Capital Spares		$ 500,000	10%	$ 50,000	$ 550,000
5000	**Non-Capital Spares (<$10,000)**					**$ 360,000**
	Spare Parts		$ 300,000	20%	$ 60,000	$ 360,000
6000	**Cost Work**					**$ 9,900,000**
	Cost Work		$ 8,250,000	20%	$ 1,650,000	$ 9,900,000

CAPITAL ESTIMATE	**$ 18,186,780**
EXPENSE ESTIMATE	**$ 10,260,000**
TOTAL ESTIMATE	**$ 28,446,780**

USS Gary - HSM NOx Controls Evaluation
Appendix B - Low NOx Burner Cost Estimates (All Furnaces)
Vendor 1 Estimate

Vendor 2 Estimate

Burners New burners
All four burner walls will be reworked to incorporate the necessary converging tile for the required air injection velocity.
Need to replace combustion air fans

Flame safety included:
Four auxiliary side fired burners to bring the soak zone above auto-ignition.
Replacement of the burner bodies in the bottom heat zone to accept a fully compliant piloted ignition system
Addition of injectors only to the top heat and top and bottom preheat zones that will be interlocked to 1400 °F permissive.
Proof of purge and low fire switches will be installed on existing air metering orifice plates
Safety PLC is included to perform the necessary flame monitoring and natural gas path select functionality

Included in cost scope:
Upgrades to combustion air system and recuperators
NG piping replacement as required - restricted piping... coke oven gas remediations
Upgrades to Level 0/1 components
Refractory

Task	Item	Vendor	Estimate	Contingency		Amount
1000	**Equipment**					**$ 12,400,000**
	Burners	VENDOR 2	$ 10,400,000	5%	$ 520,000	$ 10,920,000
	Emissions Sampling/Testing Infrastructure		$ 400,000	20%	$ 80,000	$ 480,000
	Peripheral Control Equipment (Safety PLC Provided)		$ 125,000	20%	$ 25,000	$ 150,000
	Refractory/Piping Materials		$ 600,000	20%	$ 120,000	$ 720,000
	Combustion Air Fans		$ 100,000	30%	$ 30,000	$ 130,000
1100	**Installation**					**$ 6,517,000**
	Burners		$ 4,000,000	20%	$ 800,000	$ 4,800,000
	Combustion Air Fans		$ 300,000	30%	$ 90,000	$ 390,000
	Emissions Sampling/Testing Infrastructure		$ 800,000	30%	$ 240,000	$ 1,040,000
	Model/Pie Updates		$ 90,000	30%	$ 27,000	$ 117,000
	Level 1 Updates		$ 125,000	30%	$ 45,000	$ 170,000
2900	**Engineering**					**$ 1,155,780**
	Impact Analysis and Study		$ 53,600	5%	$ 2,680	$ 56,280
	Technical Support for Impact Study		$ 20,000	5%	$ 1,000	$ 21,000
	Detailed Furnace Study	VENDOR 2	$ 150,000	20%	$ 30,000	$ 180,000
	Design of Emissions Sampling/Testing Infrastructure		$ 150,000	20%	$ 30,000	$ 180,000
	Installation Specification Development		$ 150,000	20%	$ 30,000	$ 180,000
	Constructability		$ 60,000	20%	$ 12,000	$ 72,000
	Furnace Model Modifications	VENDOR 2	$ 60,000	20%	$ 12,000	$ 72,000
	Level I Design - Burners/Flame Safety/Consulting		$ 90,000	20%	$ 18,000	$ 108,000
	As-Built Drawings - MOC		$ 160,000	20%	$ 32,000	$ 192,000
	Drawing Management		$ 90,000	5%	$ 4,500	$ 94,500
2910	**Start-up and Commissioning**					**$ 1,238,000**
	Field Supervision	VENDOR 2	$ 500,000	30%	$ 150,000	$ 650,000
	Scheduling and Cost Control		$ 90,000	20%	$ 18,000	$ 108,000
	Construction Management		$ 400,000	20%	$ 80,000	$ 480,000
3000	**Capital Spares (>$10,000)**					**$ 720,000**
	Capital Spares (combustion air fan added)		$ 600,000	20%	$ 120,000	$ 720,000
5000	**Non-Capital Spares (<$10,000)**					**$ 360,000**
	Spare Parts		$ 300,000	20%	$ 60,000	$ 360,000
6000	**Cost Work**					**$ 9,900,000**
	Cost Work		$ 8,250,000	20%	$ 1,650,000	$ 9,900,000

CAPITAL ESTIMATE	**$ 22,030,780**
EXPENSE ESTIMATE	**$ 10,260,000**
TOTAL ESTIMATE	**$ 32,290,780**

USS Gary - HSM NOx Controls Evaluation
Appendix B - Low NOx Burner Cost Estimates (All Furnaces)
Vendor 1 Estimate

Vendor 3 Estimate

Burners
- New burners
- Moderate shell steel and refractory port modifications
- The combustion air blower will be replaced with higher pressure fans
- existing recuperator, zone orifice plates and flow control valves.
- Burner drop ductwork will need to be modified as required to connect to the new burners.
- New burner expansion joints will be provided along with new burner isolation valves.
- Gas piping from the gas train to the burners will remain in place, and existing orifice plates and flow control valves will remain in service
- Piping modification to suit the new burners will be made at the burner drops
- A new level 1 control system, including new PLC hardware, remote I/O panels, HMI screens is included.

Flame safety included:
- Gas train for the furnace must be modified to comply with the latest NFPA-86 standards
- The combustion system will be designed to use the top and bottom heat zones as the light-up zones
- The top and bottom preheat zones will be ignited when the zones are above auto-ignition bypass temperature
- The furnace will be provided with new purge and safety checks for proper ignition sequence as mandated by the NFPA.
- Ignition burners will have spark ignited pilot burners with UV detector type flame supervision
- A burner management system panel will be included to house the electronic components

Task	Item	Vendor	Estimate	Contingency		Amount
1000	**Equipment**					**$ 26,600,000**
	Burners (Flame Safety Included, comb air fans)	Vendor 3	$ 24,000,000	5%	$ 1,200,000	$ 25,200,000
	Emissions Sampling/Testing Infrastructure		$ 400,000	20%	$ 80,000	$ 480,000
	Refractory/Piping Materials (burner walls need to be reworked)		$ 800,000	15%	$ 120,000	$ 920,000
1100	**Installation**					**$ 7,352,000**
	Burners		$ 5,000,000	20%	$ 1,000,000	$ 6,000,000
	Emissions Sampling/Testing Infrastructure		$ 800,000	30%	$ 240,000	$ 1,040,000
	Model/Pie Updates		$ 90,000	30%	$ 27,000	$ 117,000
	Level 1 Updates		$ 150,000	30%	$ 45,000	$ 195,000
2900	**Engineering**					**$ 975,780**
	Impact Analysis and Study		$ 53,600	5%	$ 2,680	$ 56,280
	Technical Support for Impact Study		$ 20,000	5%	$ 1,000	$ 21,000
	Design of Emissions Sampling/Testing Infrastructure		$ 150,000	20%	$ 30,000	$ 180,000
	Installation Specification Development		$ 150,000	20%	$ 30,000	$ 180,000
	Constructability		$ 60,000	20%	$ 12,000	$ 72,000
	Furnace Model Modifications	Vendor 3	$ 60,000	20%	$ 12,000	$ 72,000
	Level I Design - Burners/Flame Safety/Consulting		$ 90,000	20%	$ 18,000	$ 108,000
	As-Built Drawings - MOC		$ 160,000	20%	$ 32,000	$ 192,000
	Drawing Management		$ 90,000	5%	$ 4,500	$ 94,500
2910	**Start-up and Commissioning**					**$ 588,000**
	Scheduling and Cost Control		$ 90,000	20%	$ 18,000	$ 108,000
	Construction Management		$ 400,000	20%	$ 80,000	$ 480,000
3000	**Capital Spares (>$10,000)**					**$ 600,000**
	Capital Spares (combustion air fan added)		$ 500,000	20%	$ 100,000	$ 600,000
5000	**Non-Capital Spares (<$10,000)**					**$ 360,000**
	Spare Parts		$ 300,000	20%	$ 60,000	$ 360,000
6000	**Cost Work**					**$ 9,900,000**
	Cost Work		$ 8,250,000	20%	$ 1,650,000	$ 9,900,000

CAPITAL ESTIMATE	**$ 36,115,780**
EXPENSE ESTIMATE	**$ 10,260,000**
TOTAL ESTIMATE	**$ 46,375,780**

ATTACHMENT B – PETITION FOR RECONSIDERATION AND STAY OF THE FINAL RULE: AIR PLAN DISAPPROVALS; INTERSTATE TRANSPORT OF AIR POLLUTION FOR THE 2015 8-HOUR OZONE NATIONAL AMBIENT AIR QUALITY STANDARDS, EPA-HQ-OAR-2021-0663; EPA-R05-OAR-2022-0006; 88 FED. REG. 9,336 (FEBRUARY 13, 2023)

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April 14, 2023

VIA E-MAIL AND FEDERAL EXPRESS

Michael Regan, Administrator
Environmental Protection Agency
Office of the Administrator, Mail Code 1101A
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Petition for Reconsideration and Stay of the Final Rule: Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, EPA-HQ-OAR-2021-0663; EPA-R05-OAR-2022-0006; 88 Fed. Reg. 9,336 (February 13, 2023)

Dear Administrator Regan:

On behalf of our clients, ALLETE, Inc. d/b/a Minnesota Power; Northern States Power Company – Minnesota d/b/a/ Xcel Energy; Great River Energy; Southern Minnesota Municipal Power Agency; Cleveland-Cliffs, Inc.; and United States Steel Corporation (collectively the "Minnesota Good Neighbor Coalition"), please find enclosed a petition for reconsideration and stay of the disapproval of "prong 2" of Minnesota's State Implementation Plan ("SIP") in the United States Environmental Protection Agency's final rule: Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, EPA-HQ-OAR-2021-0663; EPA-R05-OAR-2022-0006; 88 Fed. Reg. 9,336 (February 13, 2023).

Please contact me with any questions you may have.

Sincerely,

/s/ Douglas A. McWilliams
Douglas A. McWilliams

cc: Olivia Davidson
Debra Shore
Gautam Srinivasan
Thomas Uher

Over 40 Offices across 4 Continents

Squire Patton Boggs (US) LLP is part of the international legal practice Squire Patton Boggs, which operates worldwide through a number of separate legal entities.

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Before the United States Environmental Protection Agency

In re: Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 9336 (February 13, 2023)	) EPA Docket Nos. EPA–HQ–OAR–2021–0663; EPA–R05–OAR–2022–0006; FRL–10209–01–OAR

Petition for Reconsideration and for Stay of the Air Plan Disapprovals for Interstate Transportation of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards

ALLETE, Inc. d/b/a Minnesota Power; Northern States Power Company – Minnesota d/b/a/ Xcel Energy; Great River Energy; Southern Minnesota Municipal Power Agency; Cleveland-Cliffs, Inc.; and United States Steel Corporation (collectively "Petitioners") respectfully request that the United States Environmental Protection Agency ("EPA") reconsider and stay the portion of its final rule Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 9336 (February 13, 2023) (the "SIP Disapproval") that disapproves Minnesota's state implementation plan ("SIP") for interstate transport for "prong 2" of Clean Air Act ("CAA") § 110(a)(2)(D)(i)(I), 42 U.S.C. § 7410(a)(2)(D)(i)(I).

Minnesota is uniquely situated in the SIP Disapproval. In EPA's February 13 action, Minnesota's SIP was approved for "prong 1"[1] based on EPA's finding that Minnesota does not contribute significantly to nonattainment in any downwind state. Minnesota's SIP was disapproved for "prong 2," with EPA finding that Minnesota was linked to interference with maintenance of a single downwind maintenance-only receptor. EPA has subsequently found in its promulgation of an ozone transport federal implementation plan ("FIP") that Minnesota was not linked to any downwind non-attainment or maintenance-only receptor when modeled for 2026.

Based on the best evidence available in 2018 when Minnesota submitted its SIP to EPA for approval (and on April 1, 2020 when EPA had a statutory obligation to approve or deny the Minnesota SIP), Minnesota was ***not*** linked to interference with attainment or maintenance in any downwind state. But, EPA did not timely act on the Minnesota SIP, and then it moved the goal posts. Based on new modeling and emission data EPA developed years later, (the "2016v2" modeling platform) EPA proposed to find that Minnesota was linked to two downwind maintenance-only receptors due to a modeled impact of less than 1 ppb at each receptor. In the

[1] As discussed on page 4 *infra*, EPA has divided the Good Neighbor obligation set out in Clean Air Act ("CAA") § 110(a)(2)(D), 42 U.S.C. § 7410(a)(2)(D), into two "prongs." The obligation to prohibit sources from emitting air pollutants in an amount which will "contribute significantly to nonattainment" is sometimes referred to as "prong 1," and the obligation to prohibit sources from emitting air pollutants in an amount which will "interfere with maintenance" as "prong 2."

final SIP Disapproval, EPA again revised its emissions data and modeling (the "2016v3" modeling platform) and now finds that Minnesota is linked in 2023 to only a single maintenance-only monitor, at a maximum contribution of 0.85 ppb. Further, EPA has since released updated modeling results for 2026 that show that this same monitor will be in attainment without any material reduction of emissions from Minnesota. As a result, after five years of updates, EPA's modeling results support the same conclusion that Minnesota reached in 2018, namely that additional emissions reductions are not needed to prohibit emissions in Minnesota that will contribute significantly to nonattainment, or interfere with maintenance of, the 2015 8-hour ozone NAAQS in any downwind state. We ask that EPA grant this petition for reconsideration to do what it should have done in 2018—Approve the Minnesota SIP.

The approvability of Minnesota's original SIP submittal is corroborated by two additional pieces of information that were not available during the public comment period for the proposed SIP disapproval or prior to EPA's release of its 2016v3 modeling in 2023. First, EPA's 2016v3 emissions inventory materially overstates Minnesota's 2023 NOx emissions; for example, it incorrectly assumes over 2,800 tons of NOx from an electric generating facility that has been idled since 2019 and is projected to have zero emissions in 2023. By merely correcting the projected actual NOx emissions, Minnesota has already achieved more NOx reductions than EPA's FIP would require of Minnesota. This effectively confirms Minnesota's step 3[2] conclusion in its 2018 SIP that no additional permanent or enforceable measures were needed beyond those already implemented by the state.[3]

Second, as EPA has recognized, its CAMx modeling is subject to significant bias in areas of complex meteorology, including the water/land interface occurring at the sole maintenance monitor that EPA has linked to Minnesota emissions. While EPA released with the final SIP Disapproval a review of this localized bias risk for southern Lake Michigan, that review was materially flawed and does not address the significant over-prediction bias occurring on the precise days EPA selected for use in evaluating Minnesota's SIP. As a result, EPA's general conclusion that adjusting for bias will not affect the outcome of its SIP reviews, does not apply to its review of the Minnesota SIP. To the contrary, adjusting for material bias results in the sole maintenance-only monitor to which Minnesota was linked by EPA becoming an attainment monitor in 2023. In other words, eliminating high-bias days alone completely addresses EPA's objection to Minnesota's 2018 SIP and eliminates Minnesota at Step 1 of EPA's four-step analysis.

Reconsideration is appropriate to make the above corrections to the emissions inventory and to account for modeling bias. After incorporating this new material information into the SIP analysis, we believe that EPA will conclude as we have that Minnesota's original 2018 SIP determination that it is not having a downwind impact on attainment or maintenance that requires additional permanent and enforceable measures was correct and warrants approval of

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[2] *See* page 4 *infra* for the list of four steps in EPA's 4-step framework for evaluating Good Neighbor SIP submissions.

[3] *See* Minnesota's 110(a)(1) and 110(a)(2) "Infrastructure" State Implementation Plan requirements for the National Ambient Air Quality Standards for Ozone, Promulgated in 2015, EPA-R05-OAR-2022-0006-0005, at 12 (October 1, 2018) ("2018 SIP").

the Minnesota SIP. Reconsideration is also appropriate to address a significant procedural flaw in the finalization of the SIP Disapproval. Specifically, the SIP Disapproval relies on information that was not available to EPA, Minnesota, or any other interested parties until 2023, well past the period for Minnesota's SIP submission and EPA's statutory deadline to approve Minnesota's SIP. While EPA has an obligation to use the best available evidence in making its regulatory decisions, that obligation is not unbounded and cannot be used to circumvent the procedures set forth in the Clean Air Act. When Minnesota timely submitted a SIP that is approvable based on the information known at the time, EPA had an obligation to approve the SIP. The Act does not allow EPA unfettered discretion to delay approval until new information becomes available, and then move the goalposts. For States that have done their part to invest resources in developing a timely and approvable SIP, EPA has a statutory obligation to act. EPA may still consider new scientific data and modeling after the statutory deadline, but there is a separate administrative process available to EPA that respects the State's SIP process. Minnesota should have an approved SIP and EPA should be considering whether new information is sufficiently material to require a "SIP call" pursuant to CAA § 110(k)(5), 42 U.S.C. § 7410(k)(5), to give Minnesota the opportunity to revise its SIP given the new available information. Having chosen to use this new information to disapprove prong 2 of Minnesota's SIP instead, EPA deprived Petitioners, the State, and other interested parties of significant procedural protections and opportunities for public input that were required by the Clean Air Act. Granting reconsideration allows EPA the opportunity to cure the procedural flaw that its final action is based on material information that has not been subject to the notice and comment process.

Given that new information was made available after the close of the public comment period, but before the time for judicial review, that such information actually undermines EPA's basis for disapproving prong 2 of Minnesota's 2018 SIP in the SIP Disapproval, and reconsideration would address the harms caused by significant procedural defects in the SIP Disapproval, Petitioners respectfully request that EPA grant reconsideration for the purpose of reviewing this new information and approving prong 2 of Minnesota's 2018 SIP.

Further, since the disapproval of prong 2 of Minnesota's SIP, and the continued implementation of EPA's subsequently-issued FIP, will cause irreparable harm to Petitioners, we request that EPA grant a stay of the disapproval of prong 2 of Minnesota's SIP pending reconsideration and pending judicial review, which will also address the irreparable harm caused by EPA's FIP.

I. Background

On October 1, 2015, EPA promulgated a revised primary and secondary 8-hour ozone NAAQS of 70 ppb. This created a requirement under the CAA for states to submit revised SIPs to EPA by October 1, 2018.[4] SIPs were required to meet the applicable requirements of CAA § 110(a)(2), 42 U.S.C. § 7410(a)(2), including an obligation, sometimes referred to as a "Good Neighbor" obligation, that the SIPs:

[4] 42 U.S.C. § 7410(a)(1).

(D) Contain adequate provisions—

(i) prohibiting, consistent with the provisions of this subchapter, any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—

(I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard, …

42 U.S.C. § 7410(a)(2)(D). The obligation to prohibit sources from emitting air pollutants in an amount which will "contribute significantly to nonattainment" is sometimes referred to as "prong 1," and the obligation to prohibit sources from emitting air pollutants in an amount which will "interfere with maintenance" as "prong 2," of the Good Neighbor obligation.

While EPA has never promulgated regulations imposing more specific interstate transport requirements than what is contained in the statutory text, EPA has developed a 4-step framework that it stated the agency would use to evaluate a state's compliance with its Good Neighbor obligation. Namely:

(1) Identify monitoring sites that are projected to have problems attaining and/or maintaining the NAAQS (i.e., nonattainment and/or maintenance receptors);

(2) identify states that impact those air quality problems in other (i.e., downwind) states sufficiently such that the states are considered ''linked'' and therefore warrant further review and analysis;

(3) identify the emissions reductions necessary (if any), applying a multifactor analysis, to eliminate each linked upwind state's significant contribution to nonattainment or interference with maintenance of the NAAQS at the locations identified in Step 1; and

(4) adopt permanent and enforceable measures needed to achieve those emissions reductions.[5]

Minnesota took a notably conservative approach in its SIP. First, in EPA's Transport Memo, EPA recognized that its four-step framework was not binding, and offered that states "have flexibility to follow this framework or develop alternative frameworks."[6] Despite this flexibility, Minnesota adopted EPA's framework for its SIP.[7] Second, EPA made clear, in the

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[5] *See* Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I), https://www.epa.gov/sites/default/files/2018-03/documents/transport_memo_03_27_18_1.pdf at 2-3 (March 27, 2018) ("Transport Memo").

[6] *Id.*

[7] 2018 SIP at 5.

Transport Memo and in a separate memorandum published later that year, that states did not need to adopt EPA's suggested 1% threshold for determining significant contributions and interference with maintenance at step 2.[8] Here too, Minnesota did not exercise this flexibility, and chose instead to use EPA's preferred approach.[9] Third, EPA guidance offered states flexibility regarding how to determine which downwind monitors should be considered maintenance receptors.[10] Again, Minnesota followed EPA's suggested approach.[11] In other words, while Minnesota was not required to, it followed EPA's own framework and did not rely on additional flexibilities to demonstrate that it had satisfied its Good Neighbor obligations.[12]

Minnesota also used the best information available at the time to determine its Good Neighbor obligations. Specifically, Minnesota used EPA's own modeling and modeling developed by the Lake Michigan Air Directors Consortium ("LADCO") to identify monitoring sites projected to have problems attaining or maintaining the 2015 ozone NAAQS in 2023.[13] It then projected the state's own contributions to those nonattainment and maintenance monitors using both sets of results.[14] Both EPA's and LADCO's modeling showed that Minnesota would contribute less than 1 percent of the NAAQS to all downwind receptors, with a highest receptor contribution from either model of 0.45 ppb.[15] Thus, following EPA's 4-factor framework, and using EPA's own modeling and proposed threshold, Minnesota demonstrated that it was not contributing significantly to, or interfering with maintenance of, the 2015 ozone NAAQS in any downwind state.

This alone would have been sufficient to satisfy Minnesota's Good Neighbor obligation. Minnesota also, however, included in its SIP submission a "step 3" analysis demonstrating that Minnesota emissions of ozone precursors had been reduced from 2002 through 2015 and would be further reduced by emission limitations and reductions required by other programs.[16] Under this step 3 analysis, Minnesota demonstrated that, even if the state were having more than an insignificant impact on downwind receptors (as EPA now asserts), Minnesota's existing glidepath of emissions reductions still supported a finding that no further emission control measures would

[8] Transport Memo at A-2; Analysis of Contribution Thresholds for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards (Aug. 31 2018) ("Threshold Memo")
[9] 2018 SIP at 6.
[10] Transport Memo at A-2; Consideration for Identifying Maintenance Receptors for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards, https://www.epa.gov/sites/default/files/2018-10/documents/maintenance_receptors_flexibility_memo.pdf at 3 (October 19, 2018) ("Maintenance Memo")
[11] 2018 SIP at 5.
[12] Minnesota, of course, could have taken a different approach, and might have used some of these flexibilities, had EPA indicated during the statutory review period that it was considering disapproving prong 2 of Minnesota's SIP.
[13] 2018 SIP at 5-9.
[14] *Id.*
[15] *Id.* at 8-9.
[16] *Id.* at 9-12; *see also id.* at 13.

be needed to address this impact. EPA did not meet its obligation to approve or deny Minnesota's complete and approvable SIP within 12 months of submittal.

Approximately three years after EPA's deadline to approve the Minnesota SIP, EPA proposed to disapprove Minnesota's SIP on February 22, 2022, along with SIPs from 18 other states.[17] EPA did not identify a technical error in Minnesota's submission or any inconsistency with the Good Neighbor requirements, or even EPA's own framework. In fact, EPA recognized that "the modeling the MPCA used relied on the most recently available EPA modeling at the time the state submitted its SIP submittal."[18] Nonetheless, EPA proposed to reject Minnesota's SIP because EPA chose to rely "on the Agency's most recently available modeling, which uses a more recent base year and more up-to-date emissions inventories, to identify upwind contributions and 'linkages' to downwind air quality problems in 2023 using a threshold of 1 percent of the NAAQS." *Id.* Based on this data, EPA proposed to reject Minnesota's conclusion that it was not linked to a downwind receptor, and to find instead that Minnesota was linked to two maintenance monitors in Cook County, Illinois, one with a maximum contribution of 0.97 ppb and the other 0.79 ppb.[19]

On February 13, 2023, EPA published the SIP Disapproval. In its final rule, EPA approved Minnesota's SIP as to "prong 1" but disapproved Minnesota's SIP as to "prong 2."[20] Rather than use the emissions data and modeling available to Minnesota in 2018, or even emissions data and modeling available at the time of the proposed SIP disapproval, EPA made a number of additional updates to its emissions inventories and model design to construct a new 2016v3 emissions platform, which it used to generate new air quality modeling without seeking public comment to allow affected party input to help the agency assess the accuracy of the new information utilized in the modeling.[21] Minnesota was now no longer linked to two downwind receptors. It was now linked to only a single maintenance-only receptor, at a maximum contribution of 0.85 ppb for 2023.[22]

While EPA also conducted updated modeling for 2026, it did not release this information in the docket for the SIP Disapproval, stating it was "not applicable" and "not used in this final action."[23] EPA subsequently made these results available, however, on EPA's website for its Federal Implementation Plan ("FIP") for 23 states, including Minnesota.[24] Based on EPA's modeling for 2026, Minnesota is not linked to any downwind nonattainment or maintenance-only receptor. In fact, based on EPA's modeling, the sole maintenance-only receptor Minnesota was linked to in 2023 is in attainment by 2026, and Minnesota's largest contribution to any

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[17] Air Plan Disapproval; Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin; Air Plan Disapproval; Region 5 Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 87 Fed. Reg. 9838, 9868 (February 22, 2022) ("Proposed Rule").
[18] Proposed Rule at 9867.
[19] *Id.* at 9868.
[20] *See S*IP Disapproval at 9357.
[21] *See id.* at 9339.
[22] *Id.* at 9357.
[23] *Id.* at 9344, n.49.
[24] https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs

downwind nonattainment or maintenance-only receptor is just 0.32 ppb.[25] Notably, this modeling assumed no installation of additional pollution controls in Minnesota. The only emissions reductions included from Good Neighbor obligations were an annual reduction of 139 tons NOx from emissions control optimization at EGUs.[26]

II. Grounds for Reconsideration of the SIP Disapproval

Reconsideration is justified under either CAA § 307(d)(7)(B)[27] or Administrative Procedure Act ("APA") § 553(e) (5 U.S.C. § 553(e)).[28] Under CAA § 307(d), reconsideration is *required* "[i]f the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule."[29] Courts have found that an objection was "impractical to raise" "when the final rule was not a logical outgrowth of the proposed rule." *Alon Refining Krotz Springs, Inc. v. EPA*, 936 F.3d 628, 648 (D.C. Cir. 2019) (*per curiam*). In other words, when interested parties would not have "anticipated that the change was possible, and thus reasonably should have filed their comments on the subject during the notice-and-comment period." *CSX Transp., Inc. v. Surface Transp. Bd.*, 584 F.3d 1076, 1080 (D.C. Cir. 2009) (internal quotations omitted). An objection is of central relevance to the outcome of the rule if it "provides substantial support for the argument that the regulation should be revised." *Chesapeake Climate Action Network v. EPA*, 952 F.3d 310, 322 (D.C. Cir. 2020). Under the APA, EPA has "broad discretion to reconsider" its SIP Disapproval "at any time" Under the APA. *Clean Air Council v. Pruitt*, 862 F.3d 1, 8-9 (D.C. Cir. 2017).[30]

Three grounds support reconsideration under either standard. First, EPA's 2016v3 modeling did not have the benefit of Petitioners' or other public comments. As a result, it contains a significant overestimation of 2023 emissions for Minnesota. Second, EPA's 2016v3 modeling of the sole monitor supporting a potential linkage between Minnesota and Illinois is subject to significant bias which, if corrected for, results in the same receptor modeling attainment in 2023. Third, EPA's rejection of prong 2 of Minnesota's SIP was procedurally

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[25] *See* Federal "Good Neighbor Plan" for the 2016 Ozone National Ambient Air Quality Standards, https://www.epa.gov/system/files/documents/2023-03/FRL%208670-02-OAR_Good%20Neighbor_Final_20230314_Signature_ADMIN%20%281%29.pdf, at 198 (pre-publication version).

[26] Compare *Id.* at 290, Table V.C.1-1; 291, Table V.C.1-2; and 452, Table VI.B.4.c-1.

[27] 42 U.S.C. § 76076(d)(7)(B).

[28] SIP disapprovals are not automatically subject to the exhaustion requirements of Clean Air Act § 307(d). 42 U.S.C. § 7607(d). This subsection lists 22 categories of agency action subject to the exhaustion requirement. SIP approval and disapproval, separate from issuance of a FIP, as occurred in the SIP Disapproval, is not addressed by any of these 22 categories.

[29] 42 U.S.C. § 7607(d)(7)(B).

[30] *See also Trujillo v. Gen. Elec. Co.*, 621 F.2d 1084, 1086 (10th Cir. 1980) ("Administrative agencies have an inherent authority to reconsider their own decisions, since the power to decide in the first instance carries with it the power to reconsider."); *United Gas Improvement Co. v. Callery Properties, Inc.*, 382 U.S. 223, 229 (1965) ("An agency, like a court, can undo what is wrongfully done by virtue of its order.")

improper because it was based entirely on results EPA obtained in 2023, well past the statutory deadline for Minnesota's SIP submission and EPA's decision approving or disapproving it.

A. Errors in EPA's New Emissions Data and Modeling, Which Were Not Subject to Notice and Comment, Support Reconsideration to Ensure EPA's Decision on Minnesota's SIP is Based on Valid and Accurate Information.

EPA "made a number of updates to [its] inventories and model design to construct a 2016v3 emissions platform which was used to update [EPA's] air quality modeling." SIP Disapproval at 9339. The SIP Disapproval uses "this updated modeling to inform [EPA's] final action on [state] SIP submissions," including Minnesota's. *Id.*

The new emissions inventory and modeling platform are of central relevance to EPA's rule. EPA identifies the 2016v3 platform as designed "to inform [the agency's] final action on these SIP submissions." SIP Disapproval at 9339. For Minnesota, the 2016v3 modeling results are the sole record citation EPA provides for its finding that prong 2 of Minnesota's SIP was "ultimately inadequate." *Id.* at 9357.

While there have been errors in each of EPA's inventories at each stage of the regulatory process, these new errors in the emissions inventory arose only with the publication of the final SIP Disapproval. Under both the APA and the CAA, EPA's rulemaking process requires adequate public notice and an opportunity to comment on the evidence on which EPA intends to rely for its final rules.[31] EPA's emissions inventory and modeling design changes were not made publicly available until EPA published the SIP Disapproval and several supporting documents on the same day. As a result, the public, including Petitioners, did not have the opportunity to review EPA's data and correct errors before then.

In the limited time Petitioners have had to review the 2016v3 data, we have identified significant errors in EPA's estimate of NOx emissions for 2023. As an example, EPA added 2,822 tons of NOx for Northshore Mining Co. – Silver Bay power. These boilers have been idled since October 2019 and are expected to have zero emissions in 2023. EPA itself recognizes that zero emissions are expected at this facility in both its OTP Policy Analysis, Appendix A and in its Unit-Level Allocations and Underlying Data for the Final Rule (both available at https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs). Yet EPA made no adjustment to its 2016v3 data, resulting in a significant overestimate of 2023 emissions from Minnesota used by EPA to justify disapproval of the Minnesota SIP. If EPA defends including 2,822 tons of NOx emissions for Silver Bay Power in the baseline actual emissions used to model Minnesota's downwind impact in 2023, then Minnesota's state allowance budget should be

[31] *See Small Ref. Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 540 (D.C. Cir. 1983) (adding evidence on which EPA relies after the close of the comment period would be "highly improper"); *see also Sierra Club v. Costle*, 657 F.2d 298, 400 (D.C. Cir. 1981) ("If … documents of central importance upon which EPA intended to rely had been entered on the docket too late for any meaningful public comment prior to promulgation, then both the structure and spirit of section 307 would have been violated."); *see also Kennecott Corp. v. EPA*, 684 F.2d 1007, 1019 (D.C. Cir. 1982) (finding EPA had not provided adequate opportunity for public comment on economic modeling placed in the docket only one week before promulgation of its final regulations).

increased to reflect those emissions and Silver Bay Power should receive proportional allowance allocations for the 2023 CSAPR ozone season trading program and beyond. To do otherwise would be internally inconsistent, which is an indication of arbitrary rulemaking.

For Minnesota, EPA's most recent modeling identified a single impacted maintenance monitor in 2023, at which Minnesota's maximum impact was 0.85 ppb. EPA's latest modeling projects this same receptor will be in attainment by 2026 with no reductions from Minnesota other than already "on the books" rules and regulations.[32] In other words, EPA's 2026 modeling confirms Minnesota's 2018 SIP conclusion that "the limits and controls that Minnesota already has in place across the state are sufficient to make it reasonably certain that Minnesota will not significantly contribute to nonattainment or interfere with maintenance in any other state" and that "no further controls or emissions limits are required to fulfill [Minnesota's] responsibilities under the interstate transport provisions for the 2015 ozone NAAQS under prongs 1 and 2 of Section 110(a)(2)(D)(i)(I)."[33]

Given the above considerations, EPA should grant reconsideration to reassess Minnesota's 2018 SIP in light of its own modeling showing that no further emission reductions are needed for Minnesota to satisfy its prong 2 good neighbor obligations.

B. The Sole Monitor that Links Minnesota Models in Attainment for 2023 When Bias is Removed.

Minnesota's only link to a downwind state receptor is the Alsip/Village Garage monitor located in Cook County, Illinois (170310001). This monitor is located near the southern shore of Lake Michigan at a land-water interface with complex meteorology**.** This monitor is currently measuring attainment with the 2015 ozone NAAQS using the 2021 4th highest daily maximum value (68 ppb). However, EPA's air quality modeling predicts that this monitor is at risk of violating the ozone NAAQS and, therefore, designates it as a maintenance-only receptor. Upwind states that interfere with this monitor's maintenance of the ozone NAAQS are linked through prong 2**.** However, if a corrected model predicts the monitor's maximum 2023 design value will attain the 2015 ozone NAAQS, this monitor falls out of the analysis at Step 1 and, since no other monitor links to Minnesota, EPA will have no basis for disapproval of prong 2 of Minnesota's SIP.

In the attached analysis, Alpine Geophysics demonstrates that the Cook County monitor models attainment for the 2015 ozone NAAQS in 2023. Alpine Geophysics evaluated this Cook County monitor and concluded that its location at a land-water interface at the southern shore of Lake Michigan presents highly complex meteorological conditions and ozone photochemistry that complicate the air quality model's ability to replicate ozone concentrations reliably. Of note,

[32] *See* Air Quality Modeling Final Rule Technical Support Document, https://www.epa.gov/system/files/documents/2023-03/AQ%20Modeling%20Final%20Rule%20TSD.pdf at 17, Table 3-5 (showing Monitor 170310001 no longer listed as a monitor-only receptor in the 2026 base case).
[33] 2018 SIP at 13.

EPA's application of a 12 km grid resolution in such areas is contrary to EPA's own guidance.[34] Alpine Geophysics reviewed EPA's day-specific model performance for the estimation of ozone concentrations on days EPA used to calculate future year design values and found significant bias in the majority of modeled day values used to designate this monitor site as a maintenance-only receptor. When Alpine Geophysics adjusted for this bias by using daily concentration values within acceptable normalized bias boundaries (+/- 15%), the updated list of top ten days used to designate the Cook County monitor resulted in both its average and maximum design values to be calculated in attainment with the 2015 ozone NAAQS.

When one attaining monitor modeled as a maintenance-only receptor is the sole basis for a state's linkage, a refined level of analysis is particularly important when predicting future design values and significant contribution. When that monitor is in a highly complex land-water interface area, it is not surprising for refined analysis to show significant bias. In its FIP rulemaking, EPA looked at this impact, but evaluated only one of ten Cook County monitors.[35] In doing so, EPA evaluated the only monitor out of the ten where EPA's performance-based recalculation resulted in a higher design value. As a result, EPA's sensitivity analysis materially understates the significance of the bias impact on the Alsip/Village Garage monitor and this issue remains central to EPA's evaluation of Minnesota's 2018 SIP.

Petitioners also had no ability to evaluate the bias in EPA's 2016v3 modeling of the Alsip/Village Garage monitor prior to EPA's release of its model and supporting data. As a result, this information arose after the close of the public comment period and within the time for judicial review.

Since Petitioners have identified significant bias in the sole receptor on which EPA relies to find a link to Minnesota and reject Minnesota's 2018 SIP, reconsideration is appropriate to evaluate the new information and analysis provided. When reasonably adjusting for the bias in EPA's 2016v3 modeling of that receptor, EPA will be in a position to confirm that Minnesota accurately concluded in 2018 that there are no "potential nonattainment or maintenance receptors significantly impacted by ozone transport from Minnesota in 2023" and that "[t]herefore, Minnesota does not have a responsibility to identify or implement any further controls or emissions limits to reduce downwind ozone contribution."[36]

C. Minnesota's SIP Should Have Been Approved Based on the Data Available at the Statutory Deadlines for Submission or Review.

The Clean Air Act sets out a detailed process for EPA's review of SIPs in CAA § 110(k). 42 U.S.C. § 7410(k). For timely submitted plans that have been deemed complete, like Minnesota's,

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[34] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, $PM_{2.5}$ and Regional Haze, https://www.epa.gov/sites/default/files/2020-10/documents/o3-pm-rh-modeling_guidance-2018.pdf (Nov. 29, 2018).

[35] *See* Federal "Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards Response to Public Comments on Proposed Rule, https://www.epa.gov/system/files/documents/2023-03/Response%20To%20Comments%20Document%20Final%20Rule.pdf at 196.

[36] 2018 SIP at 9.

EPA has twelve months to act on a plan submission. 42 U.S.C. § 7410(k)(2). For a plan that meets the requirements of the Clean Air Act, "the Administrator shall approve such submittal as a whole." *Id.* at (k)(3). If a portion of the plan revision meets all the applicable requirements, EPA "may approve the plan revision in part and disapprove the plan revision in part" but "[t]he plan revision shall not be treated as meeting the requirements of [the Clean Air Act] until the Administrator approves the entire plan revision as complying with the applicable requirements of [the Clean Air Act]." *Id.* In other words, while EPA has discretion to partially approve a SIP submittal that does not meet all requirements of the Clean Air Act, if a submission meets all requirements of the Act, EPA does not have discretion. It must approve the SIP. *See also Utah Physicians for a Healthy Env't v. Kennecott Utah Copper, LLC*, 191 F. Supp. 3d 1287, 1290 (D. Utah 2016) ("If a SIP satisfies the applicable requirements, EPA must approve it.").

In 2018, Minnesota submitted a timely and approvable SIP. As EPA acknowledges in the SIP Disapproval, Minnesota "was not projected to be linked to any receptor in 2023 in the EPA's 2011-based modeling."[37] Petitioners retained Alpine Geophysics to reanalyze Minnesota's SIP submission considering the best evidence available both at the time of Minnesota's SIP submission and at the time of EPA's statutory obligation to approve or disapprove Minnesota's SIP. As detailed in the attached report, Alpine Geophysics' review confirms that Minnesota's SIP submission: (1) had no material errors; (2) relied on the best science (including emissions data and modeling) available at the time; (3) fully complied with the CAA's requirements and EPA's guidance; and (4) would have been approved had EPA not incorporated information unavailable during the statutory review period. As a result, pursuant to 42 U.S.C. § 7410(k)(2) and (k)(3), by April 1, 2020, EPA had a non-discretionary duty to approve Minnesota's SIP. While EPA missed its statutory deadline, this did not relieve EPA of its duty to approve Minnesota's SIP.

While EPA now finds that "in light of more recent air quality analysis," Minnesota is linked to a single maintenance monitor in Illinois, this is based on information that did not exist at the time of Minnesota's SIP submission nor when EPA had a statutory obligation to approve the SIP. This was also not EPA's first use of untimely information to assess Minnesota's SIP. In 2022, EPA proposed to disapprove Minnesota's SIP "[s]ince new modeling ha[d] been performed by EPA with updated emission data," that EPA proposed "to primarily rely on … to identify nonattainment and maintenance receptors in 2023." Proposed Rule at 9867. As EPA acknowledged at the time, this was "a different method for projecting emissions" than what had been available to Minnesota for it to develop its SIP submittal. *Id.* EPA's repeated changes in emissions inventory and modeling platform after the deadline for SIP submissions and after Minnesota's SIP was deemed complete by EPA effectively moved the goalpost for Minnesota's SIP, undercutting the State of Minnesota's ability to identify the requirements EPA would apply to determine an approvable SIP.

The impact was significant. Minnesota's modeled impact went from contributing "below 1 percent of the NAAQS to receptors in 2023" to contributing "greater than 1 percent of the standards to two maintenance-only receptors in Illinois"[38] in the 2022 proposed SIP Disapproval

[37] SIP Disapproval at 9357.
[38] *Id.* at 9867-68.

to now being linked to one maintenance-only receptor in the 2023 SIP Disapproval (assuming no further adjustment for bias or data inaccuracies)). Notably, even using EPA's new data and modeling, Minnesota would still have had no linkage to a downwind maintenance receptor if EPA had not also moved the maximum threshold it indicated it would consider acceptable from 1 ppb to 1% (0.70 ppb).[39] As the D.C. Circuit has held, it is arbitrary and capricious to give states a "constantly moving target," *New York v. EPA*, 964 F.3d 1214, 1224 (D.C. Cir. 2020), let alone two. The language and structure of the Clean Air Act clearly give Minnesota and Petitioners the right to address this new data in the first instance in a SIP amendment, and not in a challenge to a SIP disapproval, as EPA now requires.

Notably, if EPA had followed the CAA procedures, it could have appropriately considered the new information it has developed since 2020, including the 2016v3 modeling it has introduced with the 2023 SIP Disapproval. But EPA cannot rely on its almost three year delay to circumvent the process and procedural protections set forth in the Clean Air Act. Rather, EPA was required to act on the SIP Minnesota submitted. If, after approval, EPA finds that a timely, complete and approved SIP nonetheless is "substantially inadequate … to mitigate adequately the interstate pollutant transport" or otherwise comply with the requirements of the Clean Air Act, "the Administrator shall require the State to revise the plan as necessary to correct such inadequacies." *Id.* at (k)(5). EPA also cannot simply disapprove the state's plan pending a new state submission that incorporated EPA's newly developed information, as the SIP Disapproval effectively does. In the event EPA finds a SIP Call is justified, EPA must first "notify the State of the inadequacies, and may establish reasonable deadlines (not to exceed 18 months after the date of such notice) for the submission of such plan revisions." *Id.* Further, "[s]uch findings and notice shall be public." *Id.* These procedural protections are an important component of the cooperative federalism embodied in the Clean Air Act. As courts have held, "[t]he Clean Air Act is an experiment in federalism, and the EPA may not run roughshod over the procedural prerogatives that the Act has reserved to the states, especially when … the agency is overriding state policy. *Bethlehem Steel Corp. v. Gorsuch*, 742 F.2d 1028, 1036–37 (7th Cir. 1984).

Multiple commenters, including the Minnesota Pollution Control Agency, have raised similar concerns arising from EPA's initial proposal to use 2016v2 modeling to disapprove state SIPs.[40] EPA has attempted to respond to those comments in the RTC, but in doing so, has not addressed the fundamental issue that EPA cannot disapprove a SIP that is approvable based on the information existing at the time that submittals are due, or even at the time EPA's SIP review was statutorily due, and cannot circumvent Minnesota's right to address new data in a SIP amendment, before EPA uses it to disapprove an otherwise approvable SIP. 42 U.S.C. §§ 7410(k)(3) and (5).

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[39] Minnesota did not rely on the 1 ppb threshold for its SIP submission, but as EPA acknowledged, "[t]he 2018 modeling indicated the state was not projected to contribute above one 1 percent of the NAAQS to a projected downwind nonattainment or maintenance receptor. Therefore, the state may not have considered analyzing the reasonableness and appropriateness of a 1 ppb threshold at Step 2 of the 4-step Step interstate transport framework per the August 2018 memorandum." Proposed Rule at 9867.

[40] *See* RTC at 42-59.

EPA asserts in the SIP Disapproval that its use of new modeling and data did not move the goal post for states because EPA "did not evaluate states' SIP submissions based solely on the 2016v2 emissions platform (or the 2016v3 platform…)" but rather "evaluated the SIP submissions based on the merits of the arguments put forward in each SIP submission." SIP Disapproval at 9366. For Minnesota, however, EPA cites no basis or analysis for its SIP Disapproval other than the 2016v3 modeling results. Having relied on no other information to disapprove Minnesota's SIP, EPA cannot simply assert it had an additional basis with no additional substantiation. As the D.C. Circuit has noted, EPA cannot support its decision on only a "Delphic explanation of [Minnesota's] purported failure to carry its burden of proof." *New York*, 964 F.3d at 1224.

EPA also maintains that data and modeling it developed for the Proposed Rule in 2022, and now additional data and modeling it developed for the SIP Disapproval in 2023, supports a finding that Minnesota's SIP submission is "ultimately inadequate." SIP Disapproval at 9357. But even if this were the case, it does not give EPA a right to disapprove Minnesota's 2018 SIP. For data arising after EPA's statutory deadline to approve Minnesota's SIP, EPA could no longer rely on its obligation to use the "best information available." SIP Disapproval at 9366. Interpreting the Clean Air Act otherwise would not do justice to the cooperative federalism framework Congress established in CAA § 110, and would deprive states of important procedural protections allowing them to control and direct in the first instance, the implementation of the NAAQS within their borders.

The SIP Disapproval misapplies the D.C. Circuit's reasoning in *Wisconsin*, 903 F.3d at 322, when it asserts the SIP submission deadline is "'procedural'" and that to limit EPA's decision to information available at the time of the SIP submission or EPA's statutory review deadline would elevate it above requirements "'central to the regulatory scheme.'" SIP Disapproval at 9366 (quoting *Wisconsin*, 903 F.3d at 322. Neither *Wisconsin*, nor the case on which it relies, *Sierra Club v. EPA*, 294 F.3d 155 (D.C. Cir. 2002), addressed the issue presented here. In *Wisconsin*, the court was responding to an argument that EPA should have selected 2011 as its analytic year even though that year had already passed. In *Sierra Club*, the court was responding to a contention that EPA's ability to extend a SIP submittal deadline should support its authority to extend attainment deadlines. Here, EPA argues for an exception that would swallow the rule. If EPA could simply withhold ruling on a SIP until the State's information had become stale, and then disapprove the SIP and issue a FIP based on the "best available information," the cooperative federalism structure of the NAAQS would be an empty shell.

This is also not a situation like that which arose in *EME Homer City Generation, L.P. v. EPA,* 795 F.3d 118 (D.C. Cir. 2015). There, EPA had approved state SIPs in reliance on the Clean Air Interstate Rule ("CAIR"), which was subsequently found to have "more than several fatal flaws" by the D.C. Circuit. *North Carolina v. EPA*, 531 F.3d 896, 901 (D.C.Cir.2008) (*per curiam*). In addressing whether this ruling allowed EPA to "correct" its earlier SIP approvals under 42 U.S.C. § 7410(k)(6), the D.C. Circuit found EPA could do so, but only due to the unique circumstances of that case. *EME Homer City Generation*, 795 F.3d at 135 n.12 ("Our conclusion on Subsection 7410(k)(6) is limited to the unusual circumstances here, in which a federal court says that EPA lacked statutory authority at the time to approve a SIP."). Notably, the D.C. Circuit did not decide whether EPA could rely on Clean Air Act §110(k)(6) to disapprove an approved SIP "in any other circumstances," and stated that its holding in particular "should not be read to diminish the scope or force of Subsection 7410(k)(5), which provides that whenever 'the Administrator finds that the applicable implementation plan for any area is substantially inadequate ... the Administrator shall require the State to revise the plan as necessary to correct such inadequacies.'" *Id.* (quoting 42 U.S.C. § 7410(k)(5)).

While in *EME Homer,* EPA had already approved several state SIPs, and in this rulemaking EPA has not yet approved Minnesota's SIP, this is a distinction without a difference. Minnesota submitted its SIP on October 1, 2018. It was deemed complete April 1, 2019.[41] EPA's period for review therefore ended April 1, 2020. As described in the Proposed Rule, Minnesota's SIP submission complied with the Clean Air Act and EPA's guidance for developing an interstate transport SIP for the 2015 ozone NAAQS. 87 Fed. Reg. at 9848-49. As detailed in the attached report, Alpine Geophysics' review confirms that Minnesota timely submitted an approvable SIP. By April 1, 2020, EPA had a statutory duty to approve Minnesota's SIP.

EPA's reliance on its 2016v3 modeling platform (which was not available to the public or interested parties) to reject the conclusions Minnesota reached based on the information that was available to all parties at the time is clearly of central relevance. Had EPA acted by its statutory deadline, Minnesota would have an approved SIP today. Further, while Petitioners have previously commented on the approvability of Minnesota's SIP, the basis for EPA's partial SIP Disapproval for Minnesota, including its decision to rely on its newer 2016v3 modeling platform, was not made public until the final rule. These grounds therefore arose after the close of the public comment period but before the time for judicial review. Reconsideration is therefore appropriate to address this procedural anomaly for Minnesota.

On reconsideration EPA should approve Minnesota's 2018 SIP based on the information that was available to EPA for its statutory review. The agency may then reassess whether, based on the information available today, including the above data and bias corrections, Minnesota's SIP remains sufficient to comply with prong 2 of the state's Good Neighbor obligations. For the reasons explained herein, EPA should find that the 2018 SIP was and is adequate to comply with prong 2.

III. Grounds for Stay of the SIP Disapproval

EPA has authority to stay the SIP Disapproval both pending reconsideration and pending judicial review. First, if the SIP Disapproval is subject to CAA § 307(d), a stay pending reconsideration can be granted for three months. Second, EPA has authority under the APA to stay the SIP Disapproval pending judicial review.

[41] *See* https://www3.epa.gov/airquality/urbanair/sipstatus/reports/mn_infrabypoll.html

A. A Stay Under CAA § 307(d)(7) is Appropriate.

The Clean Air Act provides that, if EPA grants reconsideration of a rule, "[t]he effectiveness of the rule may be stayed during such reconsideration…by the Administrator or the court for a period not to exceed three months." 42 U.S.C. § 7607(d)(7)(B). If the SIP Disapproval is subject to CAA § 307(d), a stay pending reconsideration is justified here.

EPA issued a final rule based primarily on emissions data and modeling that it did not make publicly available before issuance of the final rule. Even upon publication, EPA's release of data was partial and inadequate to reconstruct the modeling that EPA used for its final determinations. Obtaining the data and checking its accuracy has taken several weeks. It would take many more weeks to rerun EPA's modeling to confirm that the results support reversal of EPA's disapproval of prong 2 of Minnesota's SIP. It will likely take a similar amount of time to evaluate the evidence of bias Petitioners are submitting to confirm that it too, supports approval of Minnesota's SIP.

A stay will also not unduly impact downwind states. Minnesota is not modeled to interfere with attainment for any downwind state. Under EPA's most recent modeling, Minnesota is linked only to a single maintenance-only receptor, the most recent monitored design value of the monitor at this location was in attainment, and EPA's modeling for 2026 shows the receptor will model attainment as well with only minimal reductions from Minnesota. As EPA has itself emphasized, the SIP Disapproval does not require any action from the states.[42]

While a stay of the effective date of the SIP Disapproval for Minnesota would also prevent EPA from applying its FIP to Minnesota at the start of the upcoming ozone trading season, which is scheduled to start May 1, 2023, this is not likely to be relevant. In a recent filing, EPA has stated that the FIP is not likely to be effective until "late June to early July."[43] If EPA timely takes action on this reconsideration, this is well within the time EPA would need to conduct reconsideration. Further, while EPA has interpreted the CAA to require it "to address good neighbor obligations as expeditiously as practicable and no later than the next attainment date," RTC at 445, granting a stay of Minnesota's SIP denial pending reconsideration will not interfere with that goal. Minnesota is modeled to impact only a single maintenance-only monitor. As the D.C. Circuit has recognized, this 'may be a valid reason" to postpone addressing emission reductions until even after the next attainment date. *North Carolina v. EPA*, 531 F.3d 896, 912 (D.C. Cir. 2008). A reasonable stay to address reconsideration falls well within EPA's discretion.

B. EPA Should Stay the Effective Date of the SIP Disapproval Pending Judicial Review.

EPA can consider a stay of the entire SIP Disapproval for all affected states. Under the APA, EPA may stay the effective date of the SIP Disapproval pending judicial review when "justice

[42] *See, e.g.*, 2015 Ozone NAAQS Interstate Transport SIP Disapproval – Response to Comments ("RTC") at 466.
[43] Respondents' Consolidated Response in Opposition to the Motions for Stay of the Final Rule, *Texas v. EPA*, Case No. 23-60069, Doc. 109, at 12 (5th Cir. Filed March 27, 2023).

so requires." 5 U.S.C. § 705. Several Petitioners are filing a petition for judicial review of EPA's partial disapproval of Minnesota's SIP contemporaneously with this petition for reconsideration and stay. Multiple other petitions have already been filed for judicial review, including petitions by Arkansas, Kentucky, Oklahoma, Texas, Utah, and Wyoming. More are likely. These cases are already spread across four circuits, and additional litigation may expand the number of courts further.

The effective date of the SIP Disapproval is March 15, 2023. This effective date is significant for both legal and practical reasons. Legally, it will force EPA to promulgate a FIP within two years (though in this case EPA has already finalized its FIP). 42 U.S.C. § 7410(c)(1). States will also be required to prepare SIP revisions if they are interested in addressing the errors in EPA's analysis. Further, the significant legal flaws in EPA's SIP Disapproval discussed above, coupled with the technical and legal concerns it raises, make it likely that judicial review will result in a remand if not vacatur of the current SIP Disapproval. As a result, to avoid the unnecessary expenditure of EPA resources on a FIP, state resources on SIP revisions, and the resources of the public and regulatory industries in addressing a FIP that is likely to not be required, justice requires that the SIP Disapproval be stayed pending judicial review.

Further, while EPA is not bound to apply the same four-factor analysis used by courts for granting a judicial stay pending review, these factors indicate support for EPA in granting a stay of the SIP Disapproval. Under this standard, the considerations for a stay are:

(1) whether the stay applicant has made a strong showing that he is likely to succeed on the merits;

(2) whether the applicant will be irreparably injured absent a stay;

(3) whether issuance of the stay will substantially injure the other parties interested in the proceeding; and

(4) where the public interest lies.

Nken v. Holder, 556 U.S. 418, 434, 129 S.Ct. 1749, 173 L.Ed.2d 550 (2009) (citation omitted). These "four considerations are factors to be balanced and not prerequisites to be met." *State of Ohio ex rel. Celebrezze v. Nuclear Regul. Comm'n*, 812 F.2d 288, 290 (6th Cir. 1987).

1. Petitioners Have Made a Strong Showing They Are Likely to Succeed on the Merits

There is no fixed probability of success the agency must find in applying these considerations. "Ordinarily the party seeking a stay must show a strong or substantial likelihood of success. However, at a minimum the movant must show 'serious questions going to the merits and irreparable harm which decidedly outweighs any potential harm to the defendant if a [stay] is issued.'" *Id. (quoting In re DeLorean Motor Company*, 755 F.2d 1223, 1229 (6th Cir.1985)).

As discussed above, the SIP Disapproval has substantive and procedural flaws, each of which individually, and more so when combined, demonstrate "a high probability of success on the merits." *Ohio ex rel. Celebrezze v. Nuclear Regul. Comm'n.*, 812 F.2d 288, 290 (6th Cir.1987). Substantively, EPA's partial SIP Disapproval for Minnesota was based on an incorrect set of emissions data and biased modeling results that, when adjusted, support Minnesota's original conclusion that the state is not linked to downwind nonattainment or interference with maintenance and, even if linked, does not need to impose additional emission reductions to satisfy its Good Neighbor obligations. Procedurally, EPA did not follow the process required by the Clean Air Act for reviewing and approving Minnesota's SIP. In doing so, EPA deprived the State and Petitioners of the ability to address EPA's concerns in a SIP Call process.

Other flaws in the SIP Disapproval also strongly support a showing of likely success on the merits in a judicial challenge. In particular, we call to the agency's attention: (a) EPA's impermissible reliance on new data to disapprove prong 2 of Minnesota's SIP without providing adequate notice and an opportunity for public comment; and (b) the SIP Disapproval's subversion of the well-established and vital cooperative federalism underlying the entire Clean Air Act and in particular, the NAAQS.

a. *EPA Cannot Base its SIP Disapproval on Information that was Not Subject to Adequate Notice and Public Comment*

Under both the Administrative Procedure Act ("APA") and the CAA, EPA's rulemaking process requires adequate public notice and an opportunity to comment. *Small Ref.*, 705 F.2d at 547. This includes providing the public with the evidence on which EPA intends to rely. *Id.* at 540. Adding evidence on which EPA relies after the close of the comment period is "highly improper." *Id.* at 540; *see also Sierra Club*, 657 F.2d at 400 ("If … documents of central importance upon which EPA intended to rely had been entered on the docket too late for any meaningful public comment prior to promulgation, then both the structure and spirit of section 307 would have been violated."). Even reconsideration cannot cure an inadequate opportunity for notice and comment. *U. S. Steel v. EPA*, 595 F.2d 207, 214 (5th Cir. 1979) ("Permitting the submission of views after the effective date is no substitute for the right of interested persons to make their views known to the agency in time to influence the rulemaking process in a meaningful way.") (Internal quotations omitted).

In the SIP Disapproval, EPA "made a number of updates to [it's] inventories and model design to construct a 2016v3 emissions platform which was used to update [EPA's] air quality modeling." SIP Disapproval at 9339. The SIP Disapproval used "this updated modeling to inform [EPA's] final action on [Minnesota's] SIP submissions." *Id.* The details of these emissions inventory and modeling design changes were first described to the public in the SIP Disapproval and associated documents made publicly available the same day.[44] Even then, EPA did not make public its 2026 modeling results, reserving these for finalization of the FIP several weeks later.

[44] Even then, the supporting data and modeling platform were not made electronically available and needed to be requested by the public, which added several more weeks to gain access.

This data and modeling were clearly of central importance to EPA's disapproval of prong 2 of Minnesota's SIP. In fact, they are the sole basis for EPA's disapproval. *See* SIP disapproval at 9357 (finding Minnesota's analysis "ultimately inadequate" in light of EPA's "more recent air quality analysis"); *see also id*. (disapproving prong 2 of Minnesota's SIP because "[i]n the 2016v3 modeling, Minnesota is projected to be linked above 1 percent of the NAAQS to one maintenance-only receptor"). As a result, EPA was required to provide the public advance notice of its new data and an opportunity for meaningful public comment.

EPA's publication of its revised emissions inventory and modeling the day of the SIP Disapproval did not satisfy this requirement. In *Kennecott Corp. v. EPA*, 684 F.2d 1007, 1019 (D.C. Cir. 1982), the D.C. Circuit found EPA had not provided adequate opportunity for public comment on economic modeling placed in the docket only one week before promulgation of its final regulations. Here, EPA did not make its new emissions data and modeling publicly available until the *day* it published its final SIP Disapproval.

It is not enough to say that Petitioners had the opportunity to comment on EPA's previous version of the emissions data and modeling, or that EPA's latest data simply "incorporates comments generated during the public comment period." SIP Disapproval at 9366. As the D.C. Circuit stated in *Chesapeake*, 952 F.3d at 320, it would be an "unreasonable burden on commenters not only to identify errors in a proposed rule but also to contemplate why every theoretical course of correction the agency might pursue would be inappropriate or incorrect." The new data and modeling on which EPA relies for the SIP Disapproval differs significantly from that which was in the public record. Based on EPA's own summary of the data, Minnesota's largest contribution to a downwind maintenance receptor changed from 0.97 ppb to 0.85 ppb based on EPA's changes. *Compare* Proposed Rule at 9868 *with* SIP Disapproval at 9354. Since EPA's own adopted significant contribution threshold in the SIP Disapproval is 0.7 ppb, a change of 0.12 ppb is clearly significant.[45]

Under both the CAA and the APA, EPA was required to provide notice and an opportunity for public comment on its 2016v3 data. There is no question that EPA provided no notice or opportunity for comment. As a result, there is a high likelihood that Petitioners would be likely to prevail on the merits of a judicial challenge. This strongly supports EPA issuing a stay of the effective date of the SIP Disapproval pending judicial review.

b. *EPA Undermined State Primacy by Disapproving Minnesota's SIP Despite its Adherence to the Requirements of the Clean Air Act.*

As EPA acknowledges, "[t]he CAA establishes a framework for state-Federal partnership to implement the NAAQS based on 'cooperative federalism.'" SIP Disapproval at 9367. Under this model, "the Federal Government establishes broad standards or goals, states are given the

[45] EPA's 2016v3 modeling did not just result in significant changes to EPA's assessment of Minnesota's potential impact on downwind states. Six states (Arizona, Iowa, Kansas, New Mexico, Tennessee, and Wyoming) had their status as linked states change entirely. *See* Air Quality Modeling Technical Support Document 2015 Ozone NAAQS SIP Disapproval Final Action, https://www.regulations.gov/document/EPA-HQ-OAR-2021-0663-0017 at 24.

opportunity to determine how they wish to achieve those goals, and if states choose not to or fail to adequately implement programs to achieve those goals, a Federal agency is empowered to directly regulate to achieve the necessary ends." *Id.* Thus, "states have the obligation and opportunity in the first instance to develop an implementation plan to achieve the NAAQS under CAA section 110" and "EPA will approve SIP submissions under CAA section 110 that fully satisfy the requirements of the CAA." *Id.* As the Supreme Court has held: "[e]ach State is given wide discretion in formulating its plan, and the Act provides that the Administrator 'shall approve' the proposed plan if it has been adopted after public notice and hearing and if it meets [the CAA's] criteria." *Union Elec. Co. v. EPA*, 427 U.S. 246, 250 (1976) (*quoting* 42 U.S.C. § 7410(a)(2)).

EPA departed from this framework when it proposed a SIP disapproval based, not on any inaccuracy in Minnesota's evaluation of the data, but on EPA's preference for a different modeling platform and emissions inventory. EPA does not have the authority to condition SIP approval on the state's adoption of EPA's preferred approach, or to supplant Minnesota' interpretation of how best to achieve the goals of the CAA, as long as Minnesota complies with the requirements of the CAA.

EPA's position is predicated on an incorrect summary of its role in the SIP review process and the relevant case law. First, EPA's role is not "secondary" only in that "it occurs second in time." RTC at 425 (internal quotations omitted). EPA relies on *EPA v. EME Homer City Generation*, LP, 572 U.S. 489 (2014) for this proposition, but the case does not support EPA's position. It must be remembered that *EME Homer* involved EPA's authority to promulgate a FIP after EPA had already disapproved SIPs.[46] As a result, the Court did not address EPA's statutory duty to approve a timely and complete SIP submission, which is the issue here. The Court's "interpretations of CAA section 110(a)(2)(D)(i)(I)" on which EPA relies must be read in this light. RTC at 426. The Court upheld interpretive choices EPA made when issuing a FIP. The Court did not say EPA could delay approval until new information became available that supported its disapproval of the SIP.

Second, EPA is wrong to imply that *EME Homer* undermines the long line of cases setting out EPA's secondary (in substance, not just in time) role in developing plans to implement the NAAQS. In fact, the Supreme Court continues to cite these cases for their interpretation of EPA's role. *See West Virginia v. EPA*, 213 L. Ed. 2d 896, 142 S. Ct. 2587, 2600 (2022) ("EPA … does not choose which sources must reduce their pollution and by how much to meet the ambient pollution target. Instead, Section 110 of the Act leaves that task in the first instance to the States, requiring each 'to submit to [EPA] a plan designed to implement and maintain such standards

[46] *See EME Homer*, 572 U.S. at 507 ("The gravamen of the State respondents' challenge ***is not that EPA's disapproval of any particular SIP was erroneous***. Rather, respondents urge that, notwithstanding these disapprovals, the Agency was obliged to grant an upwind State a second opportunity to promulgate adequate SIPs once EPA set the State's emission budget. ***This claim does not depend on the validity of the prior SIP disapprovals***. Even assuming the legitimacy of those disapprovals, the question remains whether EPA was required to do more than disapprove a SIP, as the State respondents urge, to trigger the Agency's statutory authority to issue a FIP.") (emphasis added).

within its boundaries.'") (*quoting Train v. Natural Resources Defense Council, Inc.*, 421 U.S. 60, 65 (1975)).

The SIP Disapproval and RTC makes clear that EPA's disapproval of prong 2 of Minnesota's SIP was not based on a determination that Minnesota's SIP failed to meet the statutory requirements of CAA, but because EPA wanted to apply "a consistent set of policy judgments across all states for purposes of evaluating interstate transport obligations and the approvability of interstate transport SIP submissions for the 2015 ozone NAAQS under CAA section 110(a)(2)(D)(i)(I)." SIP Disapproval at 9339; *see also id.* at 9340 ("Effective policy solutions to the problem of interstate ozone transport going back to the NOx SIP Call have necessitated the application of a uniform framework of policy judgments to ensure an 'efficient and equitable' approach.") (quoting *EME Homer*, 572 U.S. at 519); RTC at 425-426. This was error. EPA's assessment of a SIP is to be based on whether the SIP compiles with the requirements of the CAA, not on EPA's policy preferences or desire for efficiency. Only after a state fails to comply with its statutory requirements can EPA impose what it believes best to achieve the substantive objective of the Act.

Because EPA's SIP Disapproval is based on improper factors that undermine the core cooperative federalism embodied in CAA § 110, Petitioners are likely to prevail on the merits of a judicial challenge. This further supports EPA issuing a stay of the effective date of the SIP Disapproval pending judicial review.

2. Petitioners Will Suffer Irreparable Harm from a Denial of Stay.

Relevant factors for evaluating the harm which will occur include: (1) the substantiality of the injury alleged; (2) the likelihood of its occurrence; and (3) the adequacy of the proof provided. In evaluating the harm which will occur both if the stay is issued and if it is not, the court must look to three factors: the substantiality of the injury alleged, the likelihood of its occurrence, and the adequacy of the proof provided. *Ohio ex re. Celebrezze*, 812 F.2d at 290 (*citing Cuomo v. United States Nuclear Regulatory Commission*, 772 F.2d 972, 974 (D.C.Cir.1985)).

The SIP Disapproval poses substantial and imminent injuries to Petitioners. As discussed in Section II above, the data which EPA should have used to evaluate Minnesota's SIP (see Section II.C), the best available data today, when flaws are addressed (see Sections II.A and B), and even the most likely future data (see Section II.D) strongly support a finding that Minnesota is not significantly contributing to nonattainment or interfering with maintenance of the 2015 ozone NAAQS in any state. EPA's SIP denial is predicated on the erroneous conclusion that there *is* interference with maintenance. This places the entire State of Minnesota in an erroneous state of non-compliance with the Good Neighbor requirement of the Clean Air Act.

EPA's SIP Disapproval also forces EPA to promulgate emission reductions through a FIP. 42 U.S.C. § 7410(c). EPA has already finalized just such a rulemaking. This leaves no time for reconsideration or judicial review to run its course before Petitioners are injured by the FIP, let alone time for Minnesota to remedy EPA's issues with the submitted SIP. Petitioners submitted detailed comments on the FIP identifying numerous substantial injuries from EPA's promulgation of its Proposed FIP that are likely to occur, and supported by substantial evidence, including detailed technical reports.[47] While EPA made substantial modification to the FIP in response to comments, which Petitioners appreciate reflects considerable work on the Agency's part following the public comment period and has addressed many significant issues with the proposed FIP, the final FIP nonetheless includes significant obligations for Petitioners' electric generating units ("EGUs"), starting in the current 2023 ozone trading season (which begins this year). Even Petitioners without EGUs are substantial consumers of electricity, meaning that they will likely bear much of the burden of the higher costs needlessly imposed on Minnesota power producers because of the FIP. Further, while the Proposed FIP is a separate rulemaking, EPA has itself identified the SIP Disapproval as both a necessary step in issuance of a final FIP[48] and the stay of a SIP disapproval that is the basis for a FIP is an appropriate remedy for injuries arising from the FIP itself. *See EME Homer City Generation, L.P. v. EPA*, 696 F.3d 7, 44 n.6 (D.C. Cir. 2012) (Rogers, J., dissenting), *rev'd on other grounds,* 572 U.S. 489 (2014) ("If [states] wish to avoid enforcement of the Transport Rule FIPs because they contend EPA's SIP disapprovals were in error, the proper course is to seek a stay of EPA's disapprovals in their pending cases; if granted, a stay would eliminate the basis upon which EPA may impose FIPs on those States.") (citing 42 U.S.C. § 7410(c)(1)(B)).

3. Staying the SIP Disapproval will not Significantly Injure Other Parties.

As discussed in Section III.A above, the SIP Disapproval does not on its own impose any emission reductions on sources. As a result, a stay will not directly harm any other party. While a stay would also potentially delay the effective date of the FIP, this is unlikely to result in significant injury to other parties. EPA has recently extended a judicially-enforceable deadline to review Good Neighbor SIPs for three states to December 15, 2023 without any mention of public harm from the delay.[49] Even as a stepping stone to a FIP, while a stay will alleviate imminent and irreparable costs, it will not significantly impact NOx emissions. As discussed above, the FIP is unlikely to be effective until after the start of the current ozone trading season, resulting in an attenuated impact on 2023 emissions. Further, even if projected emission reductions for the full 2023 ozone trading season could be achieved, EPA projects total emission reductions from Minnesota of only 139 tons in 2023. This is unlikely to result in any significant impact on the Cook County maintenance monitor.

4. The Public Interest Lies in Granting a Stay.

As courts have held, there is a public interest enjoining inequitable conduct and in minimizing unnecessary costs to be met from public coffers. *See, e.g. B & D Land & Livestock Co. v. Conner*, 534 F. Supp. 2d 891, 910 (N.D. Iowa 2008). Here, the public interest supports a stay.

[47] See Comments of U. S. Steel, EPA-HQ-OAR-2021-0668-0798 (June 27, 2022); Comments of Xcel Energy, EPA-HQ-OAR-2021-0668-0411 (June 23, 2022); Comments of Minnesota Power, EPA-HQ-OAR-2021-0668-0539 (June 23, 2022); Comments of SMMPA, EPA-HQ-OAR-2021-0668-0351 (June 22, 2022); Comments of Cleveland-Cliffs Inc., EPA-HQ-OAR-2021-0668-0405 (June 23, 2022)

[48] 88 Fed. Reg. 9336 at 9362.

[49] *See* Joint Notice of Second Stipulated Extension of Consent Decree Deadlines, Doc. 33, *Downwinders at Risk v. Regan*, Case No. 4:21-cv-3551-DMR (N.D. Cal. Jan. 30, 2023).

As discussed in Section II.A above, EPA's SIP Disapproval was promulgated through the inequitable exclusion of public participation into the data central to EPA's final rulemaking. The result will be costly public expenditures, both by EPA to promulgate an unnecessary FIP and States to either prepare to implement EPA's FIP or prepare revised SIPs, and well as unnecessary costs borne by Petitioners.

While it was an error for EPA to disapprove Minnesota's SIP based on information not in the record at the time of submission, EPA can ameliorate the harm of this error by staying the effect of its SIP disapproval until the merits of the issues above can be fully evaluated and addressed.

IV. Conclusion

The State of Minnesota has expended substantial effort and resources to regulate the emission of NOx within its borders. Those efforts have successfully reduced State impacts on downwind receptors to a point that Minnesota is not a significant contributor to nonattainment or interference with maintenance of the 2015 ozone standard in any state. Based on the best available data and modeling science available at the time, Minnesota assessed its impact on downwind states, as it was required to do under the Clean Air Act, and appropriately concluded that it was not interfering with maintenance of attainment in any state. EPA has identified no error or omission in Minnesota's analysis. Nonetheless, based on data that was not available at the time, and in fact was not available to the public until February 2023, EPA partially disapproved Minnesota's Good Neighbor plan for the sole reason that, based on EPA's own modeling, it found a single maintenance receptor in Cook County, Illinois that Minnesota state emissions were impacting at a maximum level of 0.85 ppb. Neither Minnesota, nor Petitioners, were given an opportunity to comment on EPA's modeling, fully evaluate it, or even see it, until EPA published its final SIP Disapproval. While a complete analysis of EPA's modeling would require months, based on Petitioners' review of the data specific to them, and based on expert evaluations by Alpine Geophysics of the modeling and data EPA has provided, EPA's results likely overstate the impact Minnesota is having on the Cook County monitor. Because Petitioners have provided new information that reveals flaws in EPA's emissions inventory for Minnesota and bias in EPA's modeling of the lone monitor that links Minnesota emissions to a downwind state, Petitioners have raised material new data undermining the central basis for EPA's disapproval of prong 2 of Minnesota's SIP. Petitioners therefore request that EPA grant reconsideration of its partial SIP disapproval for Minnesota and approve Minnesota's 2018 SIP. Further, to avoid the significant and irreparable harm to Petitions arising from EPA's erroneous disapproval of prong 2 of Minnesota's SIP, EPA should stay the effectiveness of its SIP Disapproval as applied to prong 2 of Minnesota's SIP pending reconsideration and pending judicial review.

Dated: April 14, 2023

Respectfully submitted,
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Attachment A

TECHNICAL REVIEW OF THE ENVIRONMENTAL PROTECTION AGENCY'S DENIAL OF MINNESOTA'S 2015 OZONE TRANSPORT SIP

Prepared by:
Alpine Geophysics, LLC
April 2023

Certified by:

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DOCUMENT OBJECTIVE

The objective of this document is for Alpine Geophysics, LLC to provide technical review and professional opinion of Minnesota Pollution Control Agency's (MPCA) SIP revision to address Clean Air Act (CAA) Section 110(a)(2)(D)(i)(I) and the Environmental Protection Agency's (EPA) final action to disapprove the Minnesota State Implementation Plan (SIP) published on February 13, 2023 in the Federal Register.

This document is formatted into three sections that discuss our review and assessment of the following issues:

A. Whether, given time to reassess, MPCA could demonstrate no linkage and/or no significant impact on attainment and maintenance in downwind states;
B. Whether U.S. EPA's revisions to its modeling approach since MPCA's SIP submittal were ancillary; and
C. Whether the Minnesota Pollution Control Agency's state implementation plan revision was approvable based on the state of the science at the time it was submitted to U.S. EPA.

At the end of this document, we also provide a summary of conclusions (Section D) and a regulatory and legislative timeline of actions taken on Minnesota's 2015 ozone SIP for reference (Section E).

A. Given time to reassess, MPCA could demonstrate no linkage and/or no significant impact on attainment and maintenance in downwind states.

EPA provided little time for MPCA to review the significant amount of technical information and associated calculations that were used to justify their disapproval of the Minnesota SIP, especially since EPA used a distinct and largely unrelated modeling platform, emissions inventory, and air quality model to justify its action instead of assessing the platform submitted by MPCA in support of its SIP. Notwithstanding the fact that four years and four months passed since the original Minnesota SIP was submitted to EPA, had appropriate time been given to MPCA to review and address EPA's final disapproval, MPCA could have addressed significant flaws in EPA's modeling that EPA itself should have addressed prior to finalizing any SIP disapproval.

It is our opinion that the U.S. EPA should have approved the MPCA's SIP when it was submitted in 2018. However, since EPA has put forward new modeling, we have reviewed this modeling and found several issues with the emissions that EPA used in the new modeling that weigh against using it as a basis for disapproving the Minnesota SIP.

1. EPA inappropriately revised the emission inventory and conducted new air quality modeling for SIP disapprovals without allowing a meaningful opportunity for stakeholder review and comment.

EPA's revisions to the emission inventory used in the modeling it previously has conducted for historic transport rules raises an administrative concern about public review and comment.

EPA notes in the proposed SIP disapprovals that, after the modeling it conducted in support of earlier transport rules, e.g., CAIR, CSAPR, CSAPR Update, CSAPR Closeout, and Revised CSAPR Update, the agency revised the emission inventory used in the modeling to assess the efficacy of prior transport rules. EPA conducted new modeling using this revised inventory and 2016v2 modeling platform. The agency describes the process as follows:

> *Following the Revised CSAPR Update final rule, the EPA made further updates to the 2016 emissions platform to include mobile emissions from the EPA's Motor Vehicle Emission Simulator MOVES3 model and updated emissions projections for electric generating units (EGUs) that reflect the emissions reductions from the Revised CSAPR Update, recent information on plant closures, and other sector trends. The construct of*

the updated emissions platform, 2016v2, is described in the emissions modeling technical support document (TSD) for this proposed rule.[1]

In December 2021, and in response to EPA requests for inventory review and updates[2,3,4], MPCA and other stakeholders submitted detailed comments on the 2016v2 emission inventory platform to correct errors that existed in that platform. EPA's declared efforts to revise this emission inventory platform at this time raised the question about whether EPA intended to update the modeling that has been used as the basis for the SIP disapprovals and the proposed FIP – but only in support of the final rule. EPA's own summary[5] of the comment process includes the statement that "by spring of 2021 it was necessary to make updates to the inventories to perform credible / defensible modeling in CY2021". In this summary, numerous and significant emission, control, and projection factor changes were requested and only with release of the final SIP denials were the changes shared by EPA for review.

As part of these comments, MPCA submitted comments on the 2016v2 emissions modeling platform (EMP) relative to three areas of improvement within Minnesota:

1. Non-electricity generation stationary (non-EGU) point source emissions controls
2. Future year emissions projections for various point and non-point inventory sectors
3. Stationary point EGU growth rate differences between the ERTAC vs IPM models

Non-EGU point source emissions controls

LADCO worked with member states to identify the highest-emitting sources and applicable control technology information for non-EGU stationary point sources in the region. They generated a spreadsheet with the highest-emitting non-EGU sources in 2016 for each LADCO state, including Minnesota, which also included state updates on emissions control information for listed sources.

A provided spreadsheet identified control information and future emission rate changes for several Minnesota sources within the 2016v2 EMP. The control information identified accounts for the installation of low NOx burners at the taconite facilities in Minnesota as part of the Regional Haze Taconite FIP. Based on MPCA estimates, just under 11,000 tpy in NOx reductions were expected due to the controls required by the Taconite FIP. MPCA noted the importance of

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[1] See: IN, IL, MN, OH, and WI proposal at 87 Fed. Reg. 9838 at 9840
[2] http://views.cira.colostate.edu/wiki/wiki/11208#September-21-2021
[3] https://cleanairact.org/wp-content/uploads/2021/10/Wayland_Monitoring-Modeling-and-Emission-Inventory-Updates_9-30-21-1.pdf
[4] https://www.epa.gov/air-emissions-modeling/2016v2-platform
[5] https://gaftp.epa.gov/Air/emismod/2016/v2/reports/comments/Summary_of_2016v2_comments_by_sector_01312022.pdf

having these significant reductions included in the EPA EMP for non-EGUs and requested that EPA do so.

Below is a summary of approximate NOx emission changes for these sources.

- 2,100 tpy at Minorca Mine
- 2,300 tpy at Hibbing Taconite
- 700 tpy at United Taconite
- 3,600 tpy at US Steel Keetac
- 2,100 tpy at US Steel Minntac

Future year emissions projections for various point and non-point inventory sectors

LADCO used US EPA-generated emissions projection reports and identified a list of SCCs that they believed had incorrect future year projection rates. The 2016v2 EMP projection rates were not found consistent either with real-world emissions trends or regional emissions projection information. It was requested that EPA replace the 2016v2 EMP projections for these sources with the updated rates provided by LADCO.

A spreadsheet was provided that included the list of the SCCs with alternative projection information and LADCO comments on the sources of the alternative information.

Stationary point EGU growth rate differences between the ERTAC vs IPM models

LADCO recognized that EPA used the Integrated Planning Model (IPM) to estimate future year EGU emissions, and that the IPM projection methodology differed from the Eastern Research Technical Advisory Committee (ERTAC) EGU model that is endorsed by the MJOs and most of the states in the eastern half of the country. Minnesota noted support for the use of ERTAC EGU projections in the 2016v2 EMP and asked EPA to consider replacing IPM projections with ERTAC EGU projections for sources in the LADCO region in subsequent modeling platforms.

While most states urged EPA to rely on modeling that accurately reflects current on-the-books regulatory requirements and up-to-date emission inventories, they also strenuously object to the possibility that EPA would conduct any such additional modeling to support a final rule. Furthermore, these states object to EPA not providing the opportunity for those data to be reviewed, analyzed, commented upon, and having those comments addressed by EPA in advance of any final decision on the subject SIP disapproval (or for that matter the related FIP). These concerns were also expressed in July 2021 by several MJOs (WESTAR, LADCO, SESARM, MARAMA, and CENSARA).[6]

[6] https://www.regulations.gov/comment/EPA-HQ-OGC-2021-0692-0012

EPA's Previously Unreleased 2016v3 Modeling Platform

EPA's newest emissions inventory and modeling platform are of central relevance to EPA's final rule. The SIP Disapproval itself identifies EPA's "updates to the 2016v2 inventories and model design to construct a 2016v3 emissions platform which was used to update the air quality modeling" and used "this updated modeling to inform its final action on these SIP submissions.[7]" These data and modeling in fact form the basis for EPA's final disapproval of Minnesota's SIP[8] (finding Minnesota's analysis "ultimately inadequate" in light of EPA's "more recent air quality analysis"). This issue also arose only with the publication of the final SIP Disapproval. EPA's publication of its revised emissions inventory and modeling did not occur until then, and states had no access to the data, the modeling, or even the results of EPA's modeling until that time.

In the limited time that states have had with the modeling data, significant errors have been identified. A robust public comment process for these data is necessary to correct all significant errors to ensure that EPA's regulatory decisions are based on valid and accurate information. Within Minnesota alone, some of these errors include the following:

- EPA incorrectly included NOx emissions of 2,822 tons in 2023 for Northshore Mining Co. – Silver Bay in the future year air quality modeling and associated significant contribution calculations but not in the engineering analysis used to calculate state level EGU budgets. The subject boilers have been idled since October 2019 and are expected to have zero emissions in 2023;

- EPA predicts zero emissions at Minnesota Power's Laskin Energy Center units that have been converted to natural gas and expect continued MISO dispatch to support the renewables transition and regional grid needs / constraints;

These errors, and many like these presumed in other states in the modeling platform, may significantly impact the results of EPA's analysis and could be the difference in nonattainment and maintenance determinations or whether Minnesota is having a downwind effect on the lone Illinois maintenance monitor that subjects Minnesota to the Good Neighbor provisions of the Clean Air Act.

It is our opinion that the absence of inclusion of Minnesota's and other stakeholder's valid EMP revision submissions, as requested by EPA, and without a rerun of the air quality model in both the base and projection year simulations, EPA cannot appropriately identify monitors as nonattainment or maintenance, and in turn, cannot calculate upwind state significant contribution metrics from these same data. Non-EGU emission controls and their associated NOx emission reductions as documented and submitted by MPCA, could be enough to change

[7] 88 FR 9339
[8] 88 FR 9357

nonattainment designations and linked significance using an updated platform, and needs to be considered before making any final decision on denial of MPCA's SIP.

2. The Cook County, Illinois monitor to which Minnesota is linked, is located at the interface of land and water along Lake Michigan and is not properly characterized by EPA's supporting modeling.

EPA did not make a bias adjustment for the only receptor that EPA found "links" Minnesota to downwind interference with maintenance. Observed values at this location (the Alsip/Village Garage monitor) demonstrate significant model overprediction, justifying the need for adjustments to address bias. While EPA has recently investigated bias in southern Lake Michigan, this assessment selectively analyzed only one monitor, which was not representative of the bias observed at the Village Garage monitor. The failue to adequately address bias in EPA's modeling resulted in an overprediction of ozone. Adjusting for this bias supports the conclusion that the Alsip monitor models in attainment of the 2015 ozone NAAQS and therefore Minnesota is not interfering with maintenance at this monitor. EPA's ozone attainment modeling guidance states that:

> *"[t]he most important factor to consider when establishing grid cell size is model response to emissions controls. Analysis of ambient data, sensitivity modeling, and past modeling results can be used to evaluate the expected response to emissions controls at various horizontal resolutions for both ozone and PM2.5 and regional haze. If model response is expected to be different (and presumably more accurate) at higher resolution, then higher resolution modeling should be considered. If model response is expected to be similar at both high and low(er) resolution, then high resolution modeling may not be necessary. The use of grid resolution finer than 12 km would generally be more appropriate for areas with a combination of complex meteorology, strong gradients in emissions sources, and/or land-water interfaces in or near the nonattainment area(s)"*

EPA's modeling in support of the SIP disapprovals simulated a national domain using a 12km grid resolution domain wide. While this makes running a national, regional simulation easier from a technical perspective, it neglects the important issue of the complex meteorology and/or land-water interfaces in or near the nonattainment or maintenance monitors of interest. Indeed, EPA's choice of a 12km grid is an arbitrary choice in contravention of its own guidance when modeling Illinois monitors in Cook County because these monitors are at land-water interfaces.

Photochemical modeling along coastlines is complex for two reasons. First, the temperature gradients along land/water interfaces can lead to localized on-shore/off-shore flows; and secondly, the photochemical model formulation spreads the emissions in a grid cell throughout the full grid volume of the cell.

Figure 1 presents a unique area along Lake Michigan that is challenged by these complex meteorologic issues at land-water interfaces. For the Cook County, Illinois monitor with which Minnesota is linked in this final rule, EPA's published model performance evaluation (MPE) metrics for ozone have been reviewed by Alpine on a day-specific basis.

Figure 1. Lake Michigan shoreline monitors located on land/water interface in Illinois.

Studies indicate that air quality forecast models typically predict large summertime ozone abundances over water relative to land and that meteorology around Lake Michigan is distinctly unique; both shortcomings warrant individualized attention and a finer grid resolution to best explore actual conditions.[9,10,11]

The 3x3 neighborhood of grid cells used in determining the design values of the relative response factor (RRF) at land-water interface monitors extends into the noted water bodies. Under current guidance, the top ten modeled days within this 3x3 matrix are used in determining this RRF for each monitor with any cell identified as 50 percent or more water, except for cells including monitors, which are omitted from the calculations.

Table 1 below provides a list of top 10 days at monitor 170310001 (Alsip/Village Garage), the Cook County monitor in Illinois to which Minnesota is linked, and comparisons of daily modeled

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[9] https://www.ladco.org/wp-content/uploads/Research/LMOS2017/LMOS_LADCO_report_revision_apr2019_final.pdf

[10] Abdi-Oskouei, M. , and Coauthors , 2020: Sensitivity of meteorological skill to selection of WRF-Chem physical parameterizations and impact on ozone prediction during the Lake Michigan Ozone Study (LMOS). J. Geophys. Res. Atmos., 125, e2019JD031971, https://doi.org/10.1029/2019JD031971.

[11] McNider, R. T. , and Coauthors, 2018: Examination of the physical atmosphere in the Great Lakes Region and its potential impact on air quality—Overwater stability and satellite assimilation. J. Appl. Meteor. Climatol., 57, 2789–2816, https://doi.org/10.1175/JAMC-D-17-0355.1.

maximum daily average 8-hour ozone concentrations (highlighted in green) and observations on the same date in 2016 (highlighted in blue). These are the dates selected in EPA's modeling to represent the highest modeled days used in estimating future year design values.

As can be seen in Table 1 below, several days selected for RRF calculation have modeled ozone concentrations that fall outside of normally acceptable normalized bias (NBias) boundaries (±15%), here as the result of over (positive bias) predictions compared to observed concentrations on those days. In fact, at the monitor example below, seven of the ten selected days fall outside of the ±15% bias metric (highlighted in orange in the Table) with a maximum normalized bias of 93.60% (observation was 45.25 ppb and modeled concentration was 87.60 ppb; a difference of over 42 ppb).

When these dates are used, EPA's calculation of future year DV is 68.2 ppb (average) and 71.9 ppb (maximum) using the average RRF of 0.9349, identifying this as a maintenance monitor.

	Monitor 170310001 – Alsip/Village Garage (Cook Co, Illinois) **Top 10 RRF - Base Dates (Modeled) –No Water - 3x3**					
		Ozone (ppb)				
Order	**Date**	**Obs**	**Base DV**	**Future DV**	**RRF**	**NBias (%)**
1	20160719	73.25	91.07	83.28	0.9144	24.33
2	20160723	45.25	87.60	81.46	0.9298	93.60
3	20160726	64.33	84.02	80.98	0.9637	30.61
4	20160810	85.88	81.35	77.20	0.9490	-5.27
5	20160803	74.38	81.04	75.31	0.9293	8.96
6	20160725	61.88	80.86	76.84	0.9503	30.67
7	20160722	54.50	79.83	76.28	0.9556	46.48
8	20160718	60.75	79.69	76.94	0.9655	31.18
9	20160804	63.75	76.21	66.23	0.8691	19.54
10	20160603	73.63	75.74	69.82	0.9219	2.87
Avg					**0.935**	

	Average	**Maximum**
Modeled 2016 DV (ppb)	73.0	77.0
Average RRF	0.935	0.935
Future 2023 DV (ppb)	68.2	71.9

Table 1. List of top 10 days at the Alsip/Village Garage monitor (170310001) in Illinois used in RRF and resulting calculated design values (ppb).

If instead a list of the top 10 days with Nbias values within normal acceptable normalized boundaries (±15%) are used, an alternate RRF value is generated, and future year average and maximum design values used in the nonattainment / maintenance designation process are recalculated.

Table 2 presents a list of top 10 days where the Nbias value is less than the acceptable ±15% normalized bias boundaries. As is seen in this table, all Nbias values fall within the parameters of the acceptable range and dates from the original top 10 list that were already within the boundaries have been maintained and are now the top 3 modeled days in the new list.

	Monitor 170310001 – Alsip/Village Garage (Cook Co, Illinois) **Top 10 RRF - Base Dates (Modeled) –Bias Adjusted - No Water - 3x3**					
		Ozone (ppb)				
Order	**Date**	**Obs**	**Base DV**	**Future DV**	**RRF**	**NBias (%)**
1	20160810	85.88	81.35	77.20	0.9490	-5.27
2	20160803	74.38	81.04	75.31	0.9293	8.96
3	20160603	73.63	75.74	69.82	0.9219	2.87
4	20160618	67.38	74.79	68.50	0.9158	11.00
5	20160619	76.25	72.60	62.88	0.8662	-4.79
6	20160727	68.75	73.92	68.92	0.9324	7.51
7	20160625	68.13	72.99	66.03	0.9046	7.14
8	20160624	74.88	70.49	66.47	0.9430	-5.86
9	20160802	62.50	71.65	66.87	0.9333	14.64
10	20160524	73.50	69.50	64.27	0.9248	-5.44

	Average	**Maximum**
Modeled 2016 DV (ppb)	73.0	77.0
Average RRF	0.922	0.922
Future 2023 DV (ppb)	67.3	70.9

Table 2. Alternate bias adjusted list of top 10 days at the Alsip/Village Garage monitor (170310001) in Illinois used in RRF and resulting calculated design values (ppb).

As a result of this bias adjusted calculation, the Alsip / Village Garage monitor located in Cook County, Illinois (170310001) has an average RRF of 0.922, resulting in an average 2023 DV of 67.3 ppb and a maximum DV of 70.9 ppb, identifying this monitor as attainment of the 2015 ozone NAAQS.

Under Step 1 of the ozone transport framework established by EPA, this monitor would not be considered as part of the list of receptors in the significant contribution calculation and therefore any linkages from upwind state contributions would be irrelevant.

Since this is the only monitor in which Minnesota is linked as a significant contributor under EPA's modeling, this linkage would be broken, and Minnesota should be removed from the list of contributing states to downwind receptors.

In the Response to Comments document from the rule, EPA attempted to address the bias issue by preparing an analysis at select monitors in the modeling domain. Specifically, EPA notes[12] that,

> *"Even though the EPA disagrees with commenter's assertion to "throw out" specific days at individual monitors for which model performance does not meet the criteria, out of an abundance of caution, the EPA performed a sensitivity analysis for selected receptors in which the projected 2023 DVs and contributions were recalculated after removing individual days that fell outside the Emery et al., criteria for normalized mean bias and/or normalized mean error. The EPA chose receptors in Coastal Connecticut, the Lake Michigan area, Dallas, and Denver for this analysis. The specific receptors included in this sensitivity analysis are Stratford, Connecticut, Chicago/Evanston, Illinois, Dallas/Denton, Texas, and Denver/Rocky Flats, Colorado."* (emphasis added)

While we agree with EPA's technical approach and calculations in their Chicago/Evanston example provided, EPA's selection of the Evanston monitor is questionable as it is the only monitor out of ten in Cook County, Illinois (three which are identified as maintenance) where performance-based recalculation results in higher design values. This is also not the unique, individual monitor to which Minnesota is exclusively linked. Table 3 presents the ten Cook County, Illinois monitors in EPA's modeling results[13].

As presented in Table 2, using bias-adjusted design values for the individual receptor with which Minnesota is linked (170310001), this monitor is calculated to be in attainment of the 2015 ozone NAAQS in 2023. This decrease is also seen in the remaining Cook County monitors that EPA did not consider in its response to comments on the issue.

[12] See pg. 196, https://www.epa.gov/system/files/documents/2023-03/Response%20To%20Comments%20Document%20Final%20Rule.pdf

[13] https://www.epa.gov/system/files/documents/2023-03/Final%20GNP%20O3%20DVs_Contributions.xlsx

			Upwind State Contribution (ppb)							
Site ID	2023 Avg DV	2023 Max DV	IN	IA	MI	MN	MO	OH	TX	WI
170310001	68.2	71.9	7.11	0.90	1.16	0.85	0.37	0.68	1.09	2.34
170310032	67.3	69.8	8.22	0.79	1.15	0.60	0.62	1.39	1.40	2.21
170310076	67.6	70.4	6.46	0.80	1.07	0.73	0.49	0.62	1.33	2.49
170311003	64.1	64.7	5.70	0.72	1.03	0.37	0.84	1.22	1.67	2.13
170311601	63.8	64.5	5.85	0.61	2.03	0.59	0.44	1.49	0.78	1.63
170313103	58.4	59.6	4.95	0.38	1.44	0.44	0.46	1.08	0.49	2.32
170314002	64.2	67.3	6.71	0.59	1.48	0.62	0.34	1.09	0.95	3.00
170314007	66.8	68.7	5.33	0.41	1.53	0.49	0.53	1.19	1.03	2.81
170314201	68.0	71.5	5.42	0.42	1.56	0.50	0.54	1.21	1.05	2.86
170317002	68.5	71.3	6.55	0.69	1.00	0.38	1.39	1.04	1.95	2.24

Table 3. Future year design values (ppb) and significant contribution calculations of upwind states to monitors in Cook County, Illinois.

Table 4 demonstrates that the Evanston monitor (170317002) in which EPA used to illustrate a noted increase in design value calculations using a bias adjustment calculation was the only monitor out of the ten where the average and maximum design values increased. Had EPA selected any other monitor from Cook County to demonstrate the bias adjustment, their conclusion may have been different than presented in the Response to Comment document.

			EPA Final Rule		Recalculated w/ Bias Adj		
Site ID	State	County	2023 Avg DV	2023 Max DV	2023 Avg DV	2023 Max DV	Bias Adj DV Change
170310001	Illinois	Cook	68.2	71.9	67.3	70.9	Decrease
170310032	Illinois	Cook	67.3	69.8	66.8	69.3	Decrease
170310076	Illinois	Cook	67.6	70.4	65.9	68.7	Decrease
170311003	Illinois	Cook	64.1	64.7	63.3	64.0	Decrease
170311601	Illinois	Cook	63.8	64.5	63.3	63.9	Decrease
170313103	Illinois	Cook	58.4	59.6	58.4	59.6	No Change
170314002	Illinois	Cook	64.2	67.3	63.2	66.3	Decrease
170314007	Illinois	Cook	66.8	68.7	66.7	68.5	Decrease
170314201	Illinois	Cook	68.0	71.5	67.3	70.7	Decrease
170317002	Illinois	Cook	68.5	71.3	69.0	71.8	Increase

Table 4. EPA final rule and bias-adjusted future year design values (ppb) of monitors in Cook County, Illinois.

Additionally, the LMOS 2017 study[14] shows that for Lake Michigan coastal monitors the air quality model even at a 4 km resolution does not simulate the proper timing and structure of the land/lake breeze or the inland penetration of elevated ozone concentrations. A review of this LMOS study[15] states "To reproduce the timing and magnitude of the ozone time series at coastal monitors, ozone production over the lake must be correctly simulated; furthermore, details of the lake breeze must be accurate——timing, horizontal extent, and vertical structure." Based on recommendations from the LMOS 2017 study research team, a horizontal resolution of at most 1.3 km is required to reasonably resolve the complex meteorology of the air/water interface for the great lakes and coastal ocean areas. The LMOS 2017 Study researchers believe that a 1.3 km grid spacing will assist in the resolution of the large ozone concentration gradients that often occur along the shoreline as well as the inland penetration of the lake breeze circulation.

As the Alsip / Village Garage example shows, days where modeled ozone was predicted at concentrations differing up to ± 42 ppb are being used to estimate future year ozone concentrations and to make determinations of nonattainment, maintenance, and significant contribution from upwind sources.

Furthermore, to adequately capture the inland penetration of the lake breeze, the LMOS report also cites the need for accurate Lake Michigan water temperatures and correct model physics options. EPA's use of the Pleim-Xiu Land Service Model (LSM) does not adequately capture the lake breeze inland penetration. A review of wind vector observations (from the Meteorological Assimilation Data Ingest System (MADIS) network) compared to modeled wind vectors on RRF and significantly contributing days at nonattainment monitors highlights the differences in wind direction and speed during many hours of these predicted high ozone episodes.

On many days with relatively simple meteorology, EPA-developed wind fields using the Weather Research and Forecasting (WRF) Model agree with the MADIS observed winds. However, the modeled winds have strong disagreement with the observed meteorology on June 15, July 7, July 27 and August 4, 2016, the four days when the CAMx model predicted the highest ozone concentrations and are thus used in estimating RRFs and future year ozone design values. The following presents an example on August 4, 2016, a day within the top ten highest model estimated MDA8 ozone concentrations at the Alsip / Village Garage monitor.

[14] https://www.ladco.org/wp-content/uploads/Research/LMOS2017/LMOS_LADCO_report_revision_apr2019_final.pdf

[15] Stanier, C. O., & et al. (2021, November). Overview of the Lake Michigan Ozone Study 2017. BAMS, 19.

In Figure 2 below, the black wind vectors are the wind fields used in the CAMx model. For clarity only every third grid cell is presented. The red vectors are the hourly observed wind vectors from the MADIS archive. The hourly results from 1300 CDT through 1600 CDT are presented in these Figures. The observations clearly show a broad persistent land to lake flow along the western shoreline while the model shows a persistent lake to land flow in this same region during this same period. For this timeframe, when the model is estimating the highest ozone for the ozone season at this receptor, the model has the winds flowing from the lake to the shore while the observations are winds flowing from the shore to the lake.

Figure 2 demonstrates that observed winds (red arrows) are seen moving from land to lake along the western shoreline of Lake Michigan, typically associated with clearing events and lower ozone levels in areas in and around Chicago. In contrast, the model (black arrows) shows a lake to land flow, typically associated with higher model predicted ozone concentrations due to the higher reactive photochemistry over water bodies.

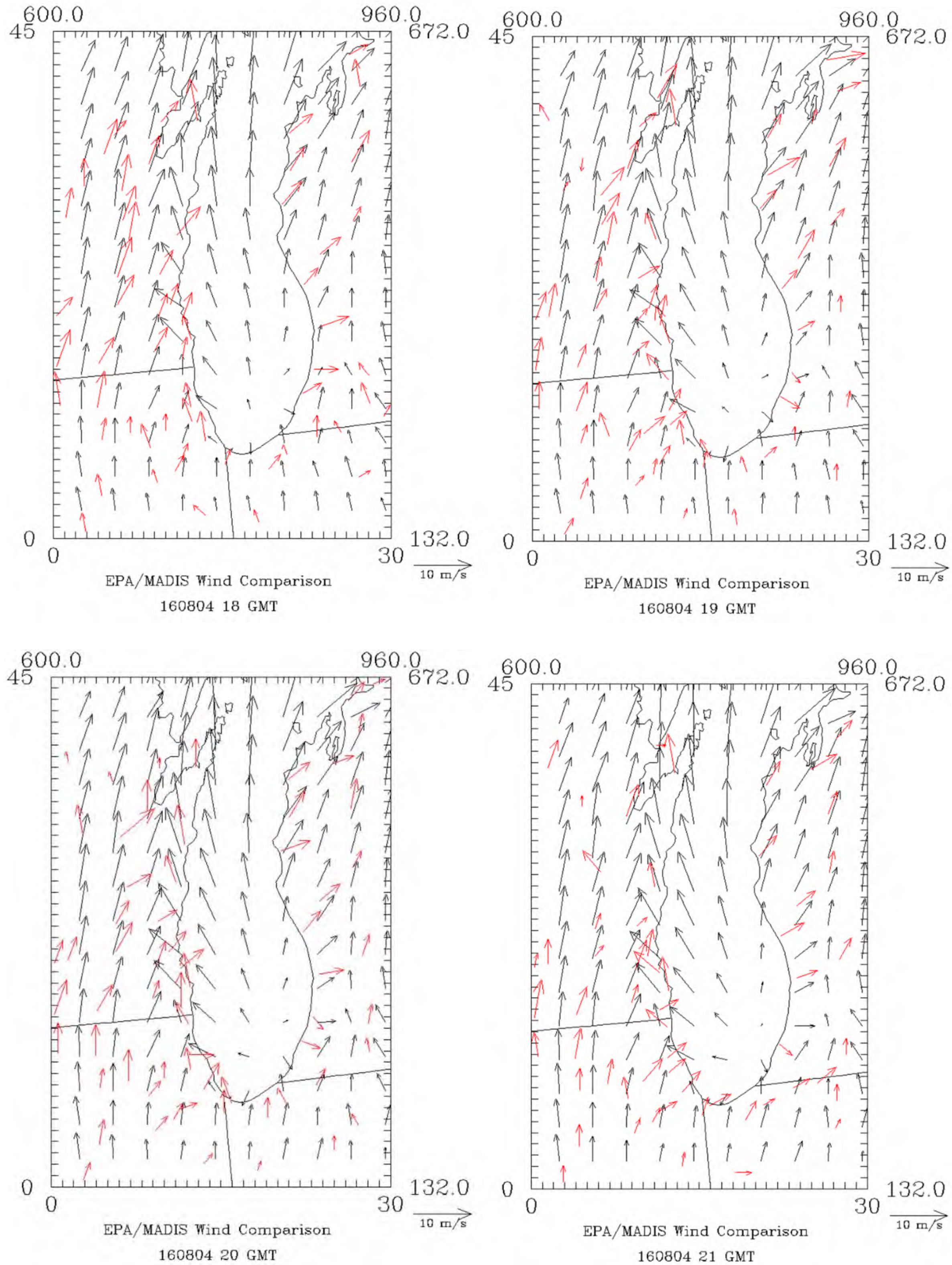

Figure 2. Model estimated (black) and observed (red) winds in the Lake Michigan area at 1300 CDT (top left), 1400 CDT (top right), 1500 CDT (bottom left), and 1600 CDT (bottom right) on August 4, 2016.

These large differences in observed and modeled wind directions are altering the concentration calculations as well as the source/receptor relationships (e.g., determining which sources are "upwind") of the Illinois monitors. As a result, the model cannot accurately reproduce the chemical processes involved with ozone formation. The erroneous modeled meteorological conditions fundamentally change the ozone formation chemistry and modeled source contributions as the chemical transport model predicts more emissions coming from the Chicago urban area than likely the case consistent with the observed wind fields.

When the model is having difficulty resolving fundamental flow patterns in this region with this grid size resolution, EPA needs to reconsider the merit of using the model with this configuration to determine nonattainment status in Step 1 as well as linked significant contributors at receptors in this region under Step 2. For these reasons, EPA must consider finer grid resolution modeling over the Lake Michigan domain to adequately capture ozone formation and significant contribution at receptors located on complex land-water interfaces because model evaluation shows that the model fails to adequately characterize ozone production at these monitors.

Absent a wholesale revision of EPA's modeling protocol, it is our opinion that EPA's use of modeling with poor performance at critical monitors amounts to an unreliable result when used to establish nonattainment or maintenance monitors under Step 1 or linkages under Step 2 of the 4-step framework. Should more refined modeling be undertaken to review the ozone formation potential at monitors located in these land-water interfaces, results may show that these monitors demonstrate modeled attainment and/or remove significant contribution linkages from upwind states.

3. EPA is obligated to address VOC emissions as a critical factor that is influencing ozone nonattainment/maintenance monitors in Illinois

EPA's modeling fails to account for VOC-limited conditions in the Lake Michigan region. Recent information supports the conclusion that VOC-limited conditions in the regional are much more significant that EPA has assumed. This results in EPA's analysis overemphasizing upwind NOx contributions from Minnesota on ozone values at the Alsip/Village Garage monitor and an underemphasis on local VOC contributions, which can be more effectively used to control ozone.

In addition to grid size resolution and complex meteorology issues, modeling performed by EPA[16] and the LMOS 2017 study both showed a negative bias in predicted ozone concentrations in the Lake Michigan region. LMOS 2017 study researchers have experimented with increasing

[16] EPA-HQ-OAR-2021-0668-0099

anthropogenic VOC emissions and decreasing anthropogenic NOx emissions. These emission changes improved air quality model performance reducing the negative bias. VOC speciation and spatio-temporal release patterns should also be reviewed. This evaluation by the LMOS 2017 research scientists indicates there are significant errors in the quantity and speciation of the VOC/NOx emissions used in the EPA's air quality modeling platform to characterize state contribution to ozone in Step 2 of EPA's analyses linking these states to critical nonattainment monitors.

Several downwind nonattainment monitors in urban areas around Lake Michigan recently have been shown to be largely unresponsive to ozone reduction strategies consisting of regional interstate NOx control and that high ozone days in the region were predominantly VOC-limited in nature. This was demonstrated in multiple ozone episodes extensively evaluated in the Lake Michigan Air Directors Consortium (LADCO) Lake Michigan Ozone Study (LMOS) 2017 study[17] where ozone precursor measurements indicated relative increases in VOC concentrations with increases in ozone and where biogenic VOC increases outpaced those of anthropogenic VOC.

In contrast to the peer reviewed research resulting from the 2017 LMOS data collection effort, EPA recently documented its support for additional NOx controls in stating that its "review of the portion of the ozone contribution attributable to anthropogenic NOX emissions versus VOC emissions from each linked upwind state leads the Agency to conclude that the vast majority of the downwind air quality areas addressed by the proposed rule under are primarily NOX-limited, rather than VOC-limited."[18] However, the current situation is that the modeling as conducted does not accurately characterize ozone levels on high ozone days, underpredicting by 10 + ppb, which is a huge error. Other studies indicate that, to better match actual conditions, the model needs less NOx and higher windspeeds at lower levels. The model is therefore demonstrating that less NOx means more ozone and higher ozone concentrations. That further means that, proportionally, the attribution of ozone to out of state NOx predicts a higher impact than is occurring.

The modeled VOC and NOx emission tracers in EPA's Anthropogenic Precursor Culpability Assessment (APCA) modeling can give a general indication of the VOC/NOx sensitivity, but EPA assigning definitive numerical values to that sensitivity provides inaccurate projections, especially using APCA that is known to have a bias toward attributing ozone to NOx emitting anthropogenic sources under VOC sensitive conditions. As documented in the CAMx v 7.10 User's Guide[19], "when ozone formation is due to biogenic VOC and anthropogenic NOx under

[17] https://www.ladco.org/wpcontent/
uploads/Research/LMOS2017/LMOS_LADCO_report_revision_apr2019_final.pdf
[18] 87 Fed. Reg. 20,076
[19] https://camx-wp.azurewebsites.net/Files/CAMxUsersGuide_v7.10.pdf, page 177.

VOC-limited conditions (a situation where OSAT would attribute ozone production to biogenic VOC), APCA attributes ozone production to the anthropogenic NOx present. Using APCA instead of OSAT results in more ozone formation attributed to anthropogenic NOx sources and less ozone formation attributed to biogenic VOC sources." Here, it is believed that as applied in this case (with biogenic emissions as an uncontrollable source group), EPA has overestimated the efficacy of NOx controls on these receptors as modeled results have a bias toward attributing more ozone formed to NOx emissions than VOC emissions.

Furthermore, an independent review of EPA's own NOx and VOC contributions challenges the Agency's statement that "[o]ur analysis of the ozone contribution from upwind states subject to regulation under this proposed rule demonstrates that the vast majority of the downwind air quality areas are NOX-limited, rather than VOC-limited."[20] This statement is based on all anthropogenic NOx and VOC emissions from all upwind states and is defined as having NOx emissions contribute to 80% or more of the ozone concentrations modeled at each receptor[21].

EPA further goes on to state that "[t]his review of the portion of the ozone contribution attributable to anthropogenic NOX emissions versus VOC emissions from each linked upwind state leads the Agency to conclude that the vast majority of the downwind air quality areas addressed by the proposed rule under are primarily NOX-limited, rather than VOC-limited."[22]

Alpine's review of EPA's modeled NOx and VOC contributions, by upwind state, focusing on the future year modeled days used in each receptor's Step 2 linkage calculation provides a slightly different picture for monitors around Lake Michigan. As demonstrated in Table 5, of the top future year modeled days impacting significant contribution calculations at the Cook County, Illinois monitor with which Minnesota is linked, more than half of the days are shown to have NOx emission contributions from Illinois below the 80% threshold noted by EPA in determining NOx-limited regions. This is an indicator that on those days, and from anthropogenic sources from those states, VOC controls may demonstrate meaningful impact on ozone concentration reductions at this receptor.

Researchers at the University of Maryland (UMD) have also found in a study of chemical transport model results that by 2023, model predictions of ozone formed under VOC-limited conditions are substantial near the Long Island Sound and the Great Lakes. In a recent presentation[23], they document a source apportionment simulation, conducted with CAMx/APCA on future-year 2023 to determine the major contributing sources and states to air

[20] 87 Fed. Reg. 20053
[21] 87 Fed. Reg. 20076
[22] Id.
[23] https://www.cmascenter.org/conference/2021/slides/allen-northeast-ambient-ozone-2021.pdf

quality within non-attainment areas. Their findings indicate that ozone production under VOC-limited conditions is important at coastal locations near Long Island Sound and the Great Lakes.

		2023 O3	O3N / O3N+O3V Contribution						
Top Day	Date	(ppb)	All	IL	IN	MI	OH	TX	WI
1	07/25/16	70.922	82.4%	81.2%	83.4%	100.0%	-	72.7%	84.1%
2	07/18/16	70.682	69.4%	64.3%	75.6%	-	-	85.9%	67.1%
3	07/19/16	70.668	79.9%	76.7%	83.7%	90.5%	-	80.5%	89.2%
4	08/10/16	67.487	79.4%	70.0%	82.4%	90.4%	86.4%	90.3%	90.6%
5	07/26/16	66.803	80.8%	72.7%	84.0%	90.7%	-	-	90.8%
6	07/23/16	63.295	84.9%	81.2%	84.0%	66.7%	-	89.7%	85.2%
7	08/03/16	61.342	88.8%	84.0%	90.9%	90.4%	92.3%	94.2%	93.8%
8	06/18/16	59.494	86.7%	72.8%	89.4%	90.1%	91.0%	90.9%	89.5%
9	06/03/16	58.730	71.5%	63.2%	73.6%	58.8%	-	74.5%	78.0%
10	08/04/16	58.241	95.0%	92.5%	96.0%	94.7%	97.1%	96.4%	94.9%

Table 5. Modeled ozone contributions to Cook, Illinois monitor (170310001) by percent of emissions from anthropogenic NOx (O3N) compared to emissions from anthropogenic NOx and VOC (O3). Yellow cells indicate contributions of anthropogenic VOC emissions greater than EPA identified "NOx-limited" areas.

Figure 3 presents UMD's findings for model predictions of ozone formation under NOx limited conditions excluding the influence of boundary and initial conditions from the modeling input. As can be seen in these figures, regions around Lake Michigan demonstrate a significantly higher percentage of ozone formed by VOC (blue in color) compared to NOx than most of the eastern US. This observation is seen both on modeled days greater than 60 ppb and on the top ten days of the ozone season (days used in RRF and significant contribution calculations).

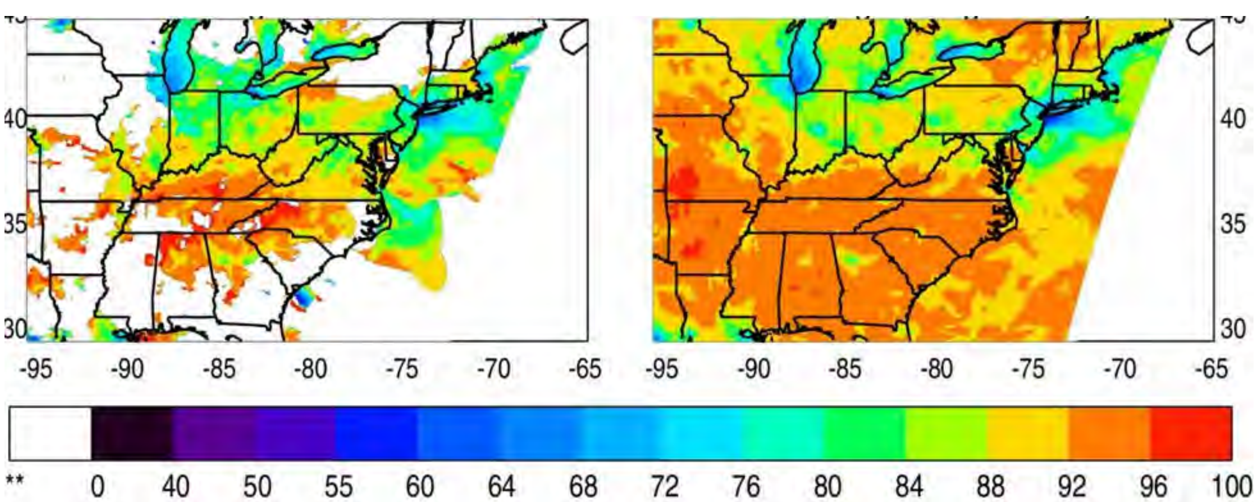

Figure 3. Percent of ozone formed under NOx-limited conditions excluding boundary and initial conditions on all days of MDA8 ozone > 60 ppb (left) and on top ten modeled days (right).

It is also noted that these estimates are a very conservatively high estimate of NOx limited conditions for these coastal areas. In addition to the previous comments highlighting that APCA is known to have a bias toward attributing ozone to NOx emitting anthropogenic sources under VOC sensitive conditions, the UMD analysis footnotes that the APCA run used to generate the results presented in Figure 3 suggests that model configuration led to an underestimation of the contribution of anthropogenic sources to ozone formation, especially during periods of VOC limited chemistry, and as is seen in Figure 3, in the Cook County, Illinois area.

As a result of these findings, EPA is obligated to address the concern that VOC emissions are a factor that is influencing ozone nonattainment and maintenance monitors in Illinois and elsewhere and that EPA determination of ozone nonattainment or maintenance in these areas may be inappropriate for significant contribution and upwind state linkage calculation. It is also our opinion that after review of VOC contribution and limited ozone reduction potential in Chicago and other noted areas, EPA may find that emission reduction plans may fail to justify regional NOx rules for monitors within these transitional and VOC-limited domains.

B. U.S. EPA's revisions to its modeling approach since MPCA's SIP submittal were ancillary.

EPA failed to give appropriate recognition of the merit of the MPCA SIP submitted on October 1, 2018, meeting the statutory deadline for submittal of interstate transport SIPs for the 2015 ozone NAAQS. The submission utilized both EPA modeling released with the March 2018 memorandum and LADCO modeling results previously mentioned. Minnesota followed the 4-step interstate transport framework and used an analytic year of 2023 to describe Minnesota's lack of contributions to out of state receptors and assess emission reduction considerations.

Under the CAA, on April 1, 2019, MPCA's SIP was deemed to be complete since EPA did not act within the 6 months from the date the SIP was submitted. April 1, 2020, 12 months after the completeness date, was the deadline for EPA to have acted on the MPCA SIP submission. Upon this deadline a full, partial or conditional approval was required by CAA Section 110(k)(2), (3), or (4).[24] In this regard, EPA failed to complete its non-discretionary duty to have reviewed and acted upon the MN SIP by April 1, 2020.

It wasn't until February 22, 2022, three years and four months after submittal, that EPA finally assessed the Minnesota SIP submittal and proposed disapproval of the SIP[25] as follows: "Based on EPA's evaluation of Minnesota's SIP submission and after consideration of updated EPA modeling using the 2016-based emissions modeling platform, EPA is proposing to find that the portion of Minnesota's October 1, 2018 SIP submission addressing CAA section 110(a)(2)(D)(i)(I) does not meet the state's interstate transport obligations for 2015 ozone NAAQS, because it fails to contain the necessary provisions to eliminate emissions that will contribute significantly to nonattainment or interfere with maintenance of the NAAQS in any other state."

The EPA reiterated this assessment and issued a partial approval on February 13, 2023, in their final rule stating that "Although the EPA acknowledges that Minnesota's Step 3 analysis was insufficient in part because the State assumed it was not linked at Step 2, this is ultimately inadequate to support a conclusion that the State's sources do not interfere with maintenance of the 2015 ozone NAAQS in other states in light of more recent air quality analysis."[26]

[24] **Deadline for Action**. – Pursuant to the CAA Section 110(k)(1)(B) "Within 12 months of a determination by the Administrator (or a determination deemed by operation of law) under paragraph (1) that a State has submitted a plan or plan revision (or, in the Administrator's discretion, part thereof) that meets the minimum criteria established pursuant to paragraph (1), if applicable (or, if those criteria are not applicable, within 12 months of submission of the plan or revision), the Administrator shall act on the submission in accordance with paragraph (3)."
[25] 87 Fed. Reg. 9838
[26] 88 Fed. Reg. 9357

1. EPA's Failure to Act

MPCA has been disadvantaged by EPA's delay in acting to approve or disapprove its 2015 Good Neighbor SIP, which was submitted to EPA on October 1, 2018. EPA published its proposed disapproval on February 22, 2022, and relied in part on newer, updated modeling performed by the EPA which was not available when MPCA submitted its revised SIP. On February 13, 2023, EPA published its final disapproval and again relied on even newer, updated modeling only released with the rule.

By delaying its final decision on Minnesota's submittal for nearly four and a half years, EPA moved the goal post for Minnesota—an act the DC Circuit rebuked in New York v. EPA, 964 F.3d 1214, 1223 (D.C. Cir. 2020). If EPA were to review and approve or disapprove SIPs within the timeframes required by the CAA, EPA would have conducted its review based on the same modeling and data that was available at the time the SIP was submitted and that has been documented in the sections above. EPA offers no indication that additional material information was available to EPA on April 1, 2020, when agency action on the Minnesota SIP was required that could justify disapproval of the Minnesota SIP.

Further, the updated modeling that EPA now offers to support a SIP review has not been adequately available to be reviewed, analyzed, and commented on in advance of any final decision on the subject SIP disapproval.

2. EPA has not developed any official guidance for states to follow in submitting a Good Neighbor SIP

The Good Neighbor SIP has been a required SIP element since the implementation of the 1997 8- hour ozone standard. In the intervening years, EPA has issued no official guidance for states to use in developing an approvable Good Neighbor SIP. It is unclear what standard or criteria EPA uses to determine approvability.

In its only direction on the subject, EPA released three 2018 memos that included modeling and discussion on potential flexibilities in approaches that could be used by states in developing their Good Neighbor SIPs. However, EPA has now disapproved MPCA's SIP which was based on EPA's own modeling results from the memo because it "does not meet the state's interstate transport obligations for 2015 ozone NAAQS, because it fails to contain the necessary provisions to eliminate emissions that will contribute significantly to nonattainment or interfere with maintenance of the NAAQS in any other state."[27]

[27] 87 FR 9869

From the memos, the only concrete guidance states have been provided is the four-step framework. Applied appropriately in the MPCA SIP, this framework demonstrated that Minnesota was not significantly linked to any downwind nonattainment or maintenance monitor. Since MPCA used EPA's own modeling and four-step approach to prepare its SIP, the SIP was approvable at the time submitted and was approvable when EPA was required to act on the SIP on April 1, 2020.

3. EPA's ever-changing list of nonattainment and maintenance monitors moves the target for Minnesota without offering any basis to reject MPCA's original analysis.

As detailed earlier, MPCA's air quality projections based on the ozone modeling conducted by LADCO in October 2018 was corroborated by EPA's own contribution modeling released with the March 2018 flexibilities memorandum and that showed that Minnesota was not linked to any monitor designated as nonattainment or maintenance for the 2015 ozone NAAQS in 2023. In those two modeling studies, the Cook County, Illinois monitor now linked to Minnesota was calculated to be in attainment for the 2015 ozone NAAQS.

Table 6 provides the average and maximum projected design values from the LADCO modeling that supported the original MPCA iSIP and March 2018 EPA memo modeling for this monitor demonstrating modeled attainment at this location.

			LADCO Modeling		EPA March 2018 Memo	
AQS Site ID	**State**	**County**	**2023 Average DV**	**2023 Maximum DV**	**2023 Average DV**	**2023 Maximum DV**
170310001	Illinois	Cook	62.8	64.6	63.2	64.9

Table 6. LADCO and EPA 2023 ozone design values (ppb) for Minnesota linked Cook County, Illinois monitor from original MPCA SIP and March 2018 EPA memo modeling results.

EPA's proposed disapproval mentions new modeling conducted by EPA in the interim where this Illinois monitor is ultimately identified as a maintenance monitor. Table 7 below provides the average and maximum projected design values from these studies and from the final SIP disapproval for this monitor.

In the proposed SIP disapproval, EPA cites the "results of a prior round of 2023 modeling using the 2016v1 emissions platform which became available to the public in the fall of 2020 in the Revised CSAPR Update." [28] In this Revised CSAPR Update modeling, developed for use with the 2008 ozone NAAQS analyses, monitor 170310001 is identified as a maintenance monitor in

[28] Footnote 94, 87 FR 9869

EPA's results. In EPA's results published in the proposed SIP disapproval[29] and in the final SIP disapproval[30], EPA continued to identify this monitor as a maintenance monitor.

AQS Site ID	EPA Revised CSAPR Update		EPA Proposed SIP Disapproval		EPA Final SIP Disapproval	
	2023 Ave DV	**2023 Max DV**	**2023 Ave DV**	**2023 Max DV**	**2023 Ave DV**	**2023 Max DV**
170310001	68.4	72.2	69.6	73.4	68.2	71.9

Table 7. EPA 2023 ozone design values (ppb) for Cook County, Illinois monitor from EPA cited modeling results in proposed and final Minnesota SIP disapproval.

In our opinion, EPA should always rely on the best available modeling at the time that an analysis is conducted and results, whether in a SIP or other, are developed and submitted. In this case, EPA has failed to follow this process and instead continued to move the target and objectives for states that, in Minnesota's case, for over four years and four months had been waiting for a review of their "best available data and analysis".

4. Alternative 1 ppb significance threshold

Neither the LADCO modeling nor EPA modeling released with the March 2018 memorandum indicated that Minnesota would contribute over 1% of the NAAQS to any nonattainment or maintenance monitor in 2023. As a result, Minnesota did not think it necessary to consider using a 1 ppb threshold for significant contribution to downwind receptors, which EPA guidance offered as an option to States.

In the SIP disapproval, EPA further elaborates that following their receipt and review of forty-nine good neighbor SIPs for the 2015 ozone NAAQS, their experience was that no state relying on a 1 ppb threshold provided sufficient information and technical support to justify that an alternative threshold was reasonable[31]. EPA does not indicate how many of the reviewed SIPs used a 1 ppb threshold nor do they indicate on how many state SIPs they provided feedback, if any. They go on to state that this alternate 1 ppb threshold may also be politically inconsistent and impractical under the CAA[32].

As EPA not only failed to provide any feedback to Minnesota on its original October 1, 2018 SIP submittal until the February 22, 2022 proposed SIP disapproval, EPA has also failed to honor its March 2018 guidance[33] which was identified to specifically "*provide analytical information*

[29] Table 5, 87 FR 9868
[30] Table III.B-2, 88 FR 9351
[31] 87 FR 9843
[32] Footnote 33, 87 FR 9843
[33] https://www.epa.gov/sites/default/files/2018-03/documents/transport_memo_03_27_18_1.pdf

regarding the degree to which certain air quality threshold amounts capture the collective amount of upwind contribution from upwind states to downwind receptors or the 2015 ozone NAAQS. It also interprets that information to make recommendation about what thresholds may be appropriate for use in state implementation plan (SIP) revisions addressing the good neighbor provision for that NAAQS."

Minnesota has been denied the opportunity to correct the model inputs that EPA uses as the basis for SIP Disapproval at the 1% threshold and denied the opportunity to update its SIP to take advantage of the 1 ppb threshold that EPA offers States an opportunity to justify in its guidance. While EPA continues to regenerate results based on updated emission modeling platforms and other associated information, states have been omitted from the process, denying them the chance to review updated information and to provide revisions to their SIPs to address those updates.

It is important to note that under all of EPA's cited modeling results, Minnesota contributes under the 1 ppb permitted to be considered from EPA's March 2018 guidance. Table 8 below shows that under none of EPA's four modeling platforms does Minnesota contribute over the 1 ppb threshold to the Cook County monitor.

			Minnesota Contribution (ppb) in 2023			
AQS Site ID	**State**	**County**	**EPA March 2018 Memo**	**EPA Revised CSAPR Update**	**EPA Proposed SIP Disapproval**	**EPA Final SIP Disapproval**
170310001	Illinois	Cook	0.76	0.79	0.97	0.85

Table 8. Minnesota contribution to Cook County, Illinois 2023 ozone design values from documented modeling platforms.

EPA's 2018 flexibility memos, including the opportunity for states to make recommendations to support alternate thresholds for significant contribution, remains an important tool for addressing unique State circumstances in developing their good neighbor SIPs. Disapproving the Minnesota SIP without affording the State an opportunity to utilize this flexibility is unreasonable and should be reconsidered.

C. The Minnesota Pollution Control Agency's state implementation plan revision was approvable based on the state of the science at the time it was submitted to U.S. EPA.

1. Introduction

On October 1, 2018, the Minnesota Pollution Control Agency, after review and comment by EPA Region 5 staff, submitted to the U.S. Environmental Protection Agency a request for revision of Minnesota's State Implementation Plan[34].

The proposed SIP revision addressed Minnesota's responsibilities relating to the "Infrastructure" SIP (iSIP) requirements of sections 110(a)(l) and 110(a)(2) of the Clean Air Act (CAA), as they pertain to the National Ambient Air Quality Standard (NAAQS) for ozone, promulgated in 2015. The CAA requires states to submit an iSIP within three years of the EPA's issuance of a new NAAQS to demonstrate their continued ability to implement, maintain, and enforce the federal standards. The iSIP outlined the statutes, rules, and programs that enable Minnesota to ensure attainment of the 2015 ozone NAAQS. These statutes, rules, and programs had previously been reviewed and approved into Minnesota's iSIP, and the materials included with the iSIP demonstrate that the MPCA did not have further obligations under the iSIP requirements.

The MPCA submission utilized both EPA modeling released with a March 2018 flexibilities memorandum[35] and Lake Michigan Air Directors Consortium (LADCO) modeling results[36]. Minnesota followed the 4-step interstate transport framework and used an analytic year of 2023 to describe Minnesota's lack of contributions to out of state receptors and assess emission reduction considerations.

In this document we discuss both the technical and legal validity of MPCA's SIP and EPA's obligation to approve the SIP.

EPA's and LADCO's model projections, along with continuing decreases in the emissions and monitored levels of ozone precursors in Minnesota (nitrogen dioxide and volatile organic compounds), demonstrated that no additional controls or emissions limits were necessary to

[34] EPA-R05-OAR-2018-0689-0003

[35] https://www.epa.gov/interstate-air-pollution-transport/memo-and-supplemental-information-regarding-interstate-transport

[36] https://www.ladco.org/wp-content/uploads/Documents/Reports/TSDs/O3/LADCO_2015O3iSIP_TSD_13Aug2018.pdf

fulfill Minnesota's responsibilities under the good neighbor provisions for the 2015 ozone NAAQS.

On February 13, 2023, almost four and a half years after the original SIP submittal, EPA finalized a rule in connection with the Air Plan Disapprovals; Interstate Transport Requirements for the 2015 8-Hour Ozone National Ambient Air Quality Standards[37].

EPA notes in this final rule, that these disapprovals would not start a mandatory sanctions clock but rather would establish a 2-year deadline for EPA to promulgate a Federal Implementation Plan (FIP), unless EPA were to approve a subsequent SIP submittal that meets CAA requirements. EPA originally proposed a FIP to be finalized December 15, 2022, in complete disregard for the 2-year period allowed by the CAA for responding to any such SIP disapprovals[38]. This FIP[39] was signed by the Administrator on March 15, 2023, and is still awaiting publication in the Federal Register.

In 2018 EPA issued flexibility guidance for states to follow in development of 2015 ozone standard NAAQS God Neighbor SIPs (GNS). We specifically question how EPA's late disapproval contradicts this guidance.

2. MPCA's Modeling Approach

The modeling performed to support the SIP was performed by LADCO and except for the 2023 projected EGU emissions, was identical to the "EN" platform developed by EPA and followed EPA guidance[40] in preparation of technical material for SIP and SIP-related modeling. The EN platform was used by EPA in its March 2018 flexibility memorandum so that "[s]tates can use these data to develop their implementation plans to assure that emissions within their jurisdictions do not contribute significantly to nonattainment or interfere with maintenance of the 2015 ozone standards in other states."

In our opinion, this platform was technically credible, and a SIP developed from these data should have been approvable by EPA at the time of submission in October 2018. The following sections present our opinions on specific technical aspects of MPCA modeling.

[37] Id.
[38] 87 Fed. Reg 20036
[39] https://www.epa.gov/system/files/documents/2023-03/FRL%208670-02-OAR_Good%20Neighbor_Final_20230314_Signature_ADMIN%20%281%29.pdf
[40] https://www.epa.gov/sites/production/files/2020-10/documents/o3-pm-rh-modeling_guidance-2018.pdf

Base Year

The base year for the MPCA modeling was 2011. 2011 was selected because of data availability and because EPA[41] had noted that 2011 meteorology in the Eastern U.S., including the upper Midwest, was warmer and drier that the climatic norm and represented typical conditions conducive to high observed ozone concentrations in the Midwest and Northeast U.S. It is Alpine's opinion that 2011 was an appropriate modeling year.

Model and Data Selection

This section introduces the models and data sources used in the MPCA. The selection methodology followed EPA's guidance for ozone regulatory modeling[42],[43],[44]. EPA's 2018 modeling guidance[45] lists several criteria for model selection that are paraphrased as follows (pp. 24-27):

- It should not be proprietary;
- It should have received a scientific peer review;
- It should be demonstrated to be applicable to the problem on a theoretical basis;
- It should be used with data bases which are available and adequate to support its application;
- It should be shown to have performed well in past modeling applications;
- It should be applied consistently with an established protocol on methods and procedures;
- It should have a user's guide and technical description;
- The availability of advanced features (e.g., probing tools or science algorithms) is desirable; and

[41] Air Quality Modeling Technical Support Document for the 2008 Ozone NAAQS Cross-State Air Pollution Rule Proposal. Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2015-11/documents/air_quality_modeling_tsd_proposed_rule.pdf

[42] Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5 and Regional Haze. U.S. Environmental Protection Agency, Research Triangle Park, NC. EPA-454/B-07-002. April, 2007. (http://www.epa.gov/ttn/scram/guidance/guide/final-03-pm-rh-guidance.pdf).

[43] Draft Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5 and Regional Haze. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, RTP, NC. December 3, 2014. (http://www.epa.gov/ttn/scram/guidance/guide/Draft_O3-PM-RH_Modeling_Guidance-2014.pdf).

[44] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, an Regional Haze. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Air Assessment Division. Research Triangle Park, NC. EPA 454/R-18-009. November 29, 2018. (https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf).

[45] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, an Regional Haze. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Air Assessment Division. Research Triangle Park, NC. EPA 454/R-18-009. November 29, 2018. (https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf).

- When other criteria are satisfied, resource considerations may be important and are a legitimate concern.

It is Alpine's opinion that the models chosen for the MPCA modeling met these criteria and were appropriate for use in the SIP.

Meteorological Modeling

The Weather Research and Forecasting (WRF) Model is a mesoscale numerical weather prediction system designed to serve both operational forecasting and atmospheric research needs[46],[47],[48]. The Advanced Research WRF (ARW) version of WRF was used in the MPCA modeling study. It features multiple dynamical cores, a 3-dimensional variational (3DVAR) data assimilation system, and a software architecture allowing for computational parallelism and system extensibility. WRF is suitable for a broad spectrum of applications across scales ranging from meters to thousands of kilometers. The effort to develop WRF has been a collaborative partnership, principally among the National Center for Atmospheric Research (NCAR), the National Oceanic and Atmospheric Administration (NOAA), the National Centers for Environmental Prediction (NCEP) and the Forecast Systems Laboratory (FSL), the Air Force Weather Agency (AFWA), the Naval Research Laboratory, the University of Oklahoma, and the Federal Aviation Administration (FAA). WRF allows researchers the ability to conduct simulations reflecting either real data or idealized configurations. WRF provides operational forecasting a model that is flexible and efficient computationally, while offering the advances in physics, numerics, and data assimilation contributed by the research community.

WRF is publicly available, has full documentation and has demonstrated success in simulating meteorological conditions in the Upper Midwest.

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[46] Skamarock, W. C. 2004. Evaluating Mesoscale NWP Models Using Kinetic Energy Spectra. *Mon. Wea. Rev.*, Volume 132, pp. 3019-3032. December, 2004. (http://www.mmm.ucar.edu/individual/skamarock/spectra_mwr_2004.pdf).

[47] Skamarock, W. C. 2006. Positive-Definite and Monotonic Limiters for Unrestricted-Time-Step Transport Schemes. *Mon. Wea. Rev.*, Volume 134, pp. 2241-2242. June. (http://www.mmm.ucar.edu/individual/skamarock/advect3d_mwr.pdf).

[48] Skamarock, W. C., J. B. Klemp, J. Dudhia, D. O. Gill, D. M. Barker, W. Wang and J. G. Powers. 2005. A Description of the Advanced Research WRF Version 2. National Center for Atmospheric Research (NCAR), Boulder, CO. June. (http://www.mmm.ucar.edu/wrf/users/docs/arw_v2.pdf)

MPCA used the U.S. EPA 2011 WRF data for this study[49]. The U.S. EPA used version 3.4 of the WRF model, initialized with the 12-km North American Model (NAM) from the National Climatic Data Center (NCDC) to simulate 2011 meteorology. Complete details of the WRF simulation, including the input data, physics options, and four-dimensional data assimilation (FDDA) configuration are detailed in the U.S. EPA 2008 Transport Modeling technical support document[50]. U.S. EPA prepared the WRF data for input to CAMx with version 4.3 of the WRFCAMx software.

It is Alpine's opinion that the U.S. EPA WRF 3.4 meteorological modeling was appropriate for use in the MPCA SIP.

Initial and Boundary Conditions

MPCA used 2011 initial and boundary conditions for CAMx generated by the U.S. EPA from the GEOS-Chem Global Chemical Transport Model[51]. EPA generated hourly, one-way nested boundary conditions (i.e., global-scale to regional-scale) from a 2011 2.0 degree x 2.5 degree GEOS-Chem simulation. Following the convention of the U.S. EPA O3 transport modeling, year 2011 GEOS-Chem boundary conditions were used by LADCO for modeling 2023 air quality with CAMx.

It is Alpine's opinion that the U.S. EPA GEOS-Chem derived initial and boundary conditions were appropriate for use in the MPCA SIP.

Emissions

The 2023 emissions data for the MPCA SIP were based on the U.S. EPA 2011v6.3 ("EN") emissions modeling platform[52]. U.S. EPA generated this platform for their final assessment of Interstate Transport for the 2008 O3 NAAQS. Updates from earlier 2011-based emissions modeling platforms included a new engineering approach for forecasting emissions from Electricity Generating Units (EGUs). LADCO replaced the EGU emissions in the U.S. EPA EN

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[49] US EPA. 2017. Memorandum: Supplemental Information on the Interstate Transport SIP Submissions for the 2008 Ozone NAAQS under Clean Air Act Section 110(a)(2)(D)(i)(I), Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2017-10/documents/final_2008_o3_naaqs_transport_memo_10-27-17b.pdf.

[50] US EPA. 2014. Meteorological Model Performance for Annual 2011 WRFv3.4 Simulation. Research Triangle Park, NC. https://www3.epa.gov/ttn/scram/reports/MET_TSD_2011_final_11-26-14.pdf.

[51] US EPA. 2017. Memorandum: Supplemental Information on the Interstate Transport SIP Submissions for the 2008 Ozone NAAQS under Clean Air Act Section 110(a)(2)(D)(i)(I), Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2017-10/documents/final_2008_o3_naaqs_transport_memo_10-27-17b.pdf.

[52] US EPA. 2017. Technical Support Document: Additional Updates to Emissions Inventories for the Version 6.3 Emissions Modeling Platform for the Year 2023. Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2017-11/documents/2011v6.3_2023en_update_emismod_tsd_oct2017.pdf

platform with 2023 EGU forecasts estimated with the ERTAC EGU Tool version 2.7[53]. ERTAC EGU 2.7 integrates state-reported information on EGU operations and forecasts as of May 2017. The MPCA believes "power sector emissions forecasts must address economic factors, preserve system reliability, and include controls or emission reduction measures justified through some legal framework. It is our understanding that the engineering analysis used by EPA to project EGU emissions to 2023 (version EN of the modeling platform) does not comply with these key requirements. The ERTAC estimates incorporate the key requirements."[54]

In March 2018 U.S. EPA released it flexibilities memo that described a series of flexibilities that states could consider in developing Good Neighbor SIPs for the 2015 ozone NAAQS. The "[u]se of alternative power sector modeling consistent with EPA's emissions inventory guidance" is presented in the Analytics section of EPA's March 2018 memo as a flexibility to consider in preparing a Good Neighbor SIP. This flexibility supports LADCO's use of the ERTAC EGU model for projecting EGU emissions to 2023. MPCA considers the emissions projections from ERTAC EGU to be more representative of the sources in the Midwest and Northeast than the approach used by U.S. EPA in their 2023 EN modeling platform. As ERTAC EGU is developed in collaboration between regional and state air planning agencies, it includes algorithms and data that have been reviewed by many of the states impacted by interstate O3 transport in the Midwest and Eastern U.S.

Preparation of the emissions data to support photochemical models is a very complicated process that entails the use of a number of different "sub-models" to prepare different emission segments.

Sparse Matrix Operator Kernel Emissions (SMOKE)

The Sparse Matrix Operator Kernel Emissions (SMOKE) is an emissions modeling system that generates hourly gridded speciated emission inputs of mobile, non-road, area, point, fire and biogenic emission sources for PGMs[55],[56]. As with most "emissions models," SMOKE is principally an emission processing system and not a true emissions modeling system in which emissions estimates are simulated from "first principles." This means that, except for mobile and biogenic sources, its purpose is to provide an efficient, modern tool for converting an existing base emissions inventory data that is typically at the county or point source level into

[53] http://www.marama.org/2013-ertac-egu-forecasting-tool-documentation

[54] EPA-R05-OAR-2018-0689-0003

[55] Coats, C.J. 1995. Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System, MCNC Environmental Programs, Research Triangle Park, NC.

[56] UNC. 2018. SMOKE v4.6 User's Manuel. University of North Carolina at Chapel Hill, Institute for the Environment. Chapel Hill, North Carolina. September 24. (https://www.cmascenter.org/smoke/documentation/4.6/manual_smokev46.pdf).

the hourly gridded speciated formatted emission files required by a Photochemical Grid Model (PGM), like CAMx. SMOKE was used to prepare emission inputs for non-road mobile, non-point (area) and point sources. SMOKE performs three main function to convert emissions to the hourly gridded emission inputs for a PGM: (1) spatial allocation, spatial allocates county-level emissions to the PGM model grid cells typically using a surrogate distribution (e.g., population); (2) temporal allocation, allocates annual emissions to time of year (e.g., monthly or seasonally) and day-of-week (typically weekday, Saturday and Sunday); and (3) chemical speciation, maps the emissions to the species in the chemical mechanism used by the photochemical grid model, most important for VOC and $PM_{2.5}$ emissions.

The primary emissions modeling tool used to create the air quality model-ready emissions was the SMOKE modeling system version 3.7 which was used to create emissions files for a 12-km national grid "12US2" that includes all of the contiguous states.

It is Alpine's opinion that the SMOKE emissions model together with the other EPA emissions was appropriate for use in the MPCA SIP.

Motor Vehicle Emissions Simulator (MOVES)

The motor vehicle emissions were prepared by U.S. EPA using the MOVES 2014a emissions model[57],[58],[59]. MOVES 2014a was the most up to date released motor vehicle emissions processor at the time of the MPCA SIP submission and it is Alpine's opinion that the U.S. EPA MOVES 2014a emissions were appropriate for use in the MPCA SIP.

Eastern Regional Technical Advisory Committee EGU Model

The Eastern Regional Technical Advisory Committee (ERTAC) EGU model for growth was developed around activity pattern matching algorithms designed to provide hourly EGU emissions data for air quality planning. The original goal of the model was to create low-cost software that air quality planning agencies could use for developing EGU emissions projections. States needed a transparent model that was numerically stable and did not produce dramatic changes to the emissions forecasts with small changes in inputs. A key feature of the model

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[57] EPA. 2014a. Motor Vehicle Emissions Simulator (MOVES) – User Guide for MOVES2014. Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. (EPA-420-B-14-055). July. (http://www.epa.gov/oms/models/moves/documents/420b14055.pdf).

[58] EPA. 2014b. Motor Vehicle Emissions Simulator (MOVES) –MOVES2014 User Interface Manual. Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. (EPA-420-B-14-067). July. (http://www.epa.gov/oms/models/moves/documents/420b14057.pdf).

[59] EPA. 2014b. Motor Vehicle Emissions Simulator (MOVES) –MOVES2014 User Interface Manual. Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. (EPA-420-B-14-067). July. (http://www.epa.gov/oms/models/moves/documents/420b14057.pdf).

includes data transparency; all of the inputs to the model are publicly available. The code is also operationally transparent and includes extensive documentation, open-source code, and a diverse user community to support new users of the software.

Operation of the model is straightforward given the complexity of the projection calculations and inputs. The model imports base year Continuous Emissions Monitoring (CEM) data from U.S. EPA and sorts the data from the peak to the lowest generation hour. It applies hour specific growth rates that include peak and off-peak rates. The model then balances the system for all units and hours that exceed physical or regulatory limits. ERTAC EGU applies future year controls to the emissions estimates and tests for reserve capacity, generates quality assurance reports, and converts the outputs to SMOKE ready modeling files.

ERTAC EGU has distinct advantages over other growth methodologies because it can generate hourly future year estimates which are key to understanding ozone episodes. The model does not shutdown or mothball existing units because economics algorithms suggest they are not economically viable. Additionally, alternate control scenarios are easy to simulate with the model. Full documentation for the ERTAC Emissions model and 2.7 simulations are available through the MARAMA website[60].

Differences between the EPA and ERTAC EGU emissions forecasts arise from alternative forecast algorithms and from the data used to inform the model predictions. The U.S. EPA EGU forecast used in the 2023 EN modeling used CEM data available through the end of 2016 and comments from states and stakeholders received through April 17, 2017[61]. ERTAC EGU 2.7 used CEM data from 2011 and state-reported changes to EGUs through May 2017. The ERTAC EGU 2.7 emissions used for the modeling represented the best available information on EGU forecasts for the Midwest and Eastern U.S. available during Spring-early Summer 2018.

The "consideration of state-specific information in identifying sources [e.g., electric generating units (EGUs) and non-EGUs] and controls" is one of the potential approaches in EPA's March 2018 flexibilities memorandum. The use of the ERTAC EGU tool falls squarely within the parameters of this documented flexibility and it is Alpine's opinion that MPCA's used of EGU emission projections from this model were appropriate in the MPCA SIP.

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[60] http://www.marama.org/2013-ertac-egu-forecasting-tool-documentation

[61] US EPA. 2017. Memorandum: Supplemental Information on the Interstate Transport SIP Submissions for the 2008 Ozone NAAQS under Clean Air Act Section 110(a)(2)(D)(i)(I), Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2017-10/documents/final_2008_o3_naaqs_transport_memo_10-27-17b.pdf.

BEIS

Biogenic emissions were computed by U. S. EPA based on the same version of the 2011 meteorology data used for the air quality modeling and were developed using the Biogenic Emission Inventory System version 3.61 (BEIS3.61) within SMOKE. The landuse input into BEIS3.61 is the BELD version 4.1 which is based on an updated version of the USDA-USFS Forest Inventory and Analysis (FIA) vegetation speciation-based data from 2001 to 2014 from the FIA version 5.1.

It is Alpine's opinion that the U.S. EPA application of the BEIS model was appropriate for use in the MPCA SIP.

3. Air Quality Modeling

The MPCA modeling used the Comprehensive Air-quality Model with Extensions (CAMx) air quality model[62]. CAMx is a state-of-science "One-Atmosphere" multi-scale photochemical grid model (PGM) capable of addressing ozone, particulate matter (PM), visibility and acid deposition at regional, urban and local scale typically for periods of a year. CAMx is a publicly available open-source computer modeling system for the integrated assessment of gaseous and particulate air pollution. Built on today's understanding that air quality issues are complex, interrelated, and reach beyond the urban scale, CAMx is designed to (a) simulate air quality over many geographic scales, (b) treat a wide variety of inert and chemically active pollutants including ozone, inorganic and organic $PM_{2.5}$ and PM_{10} and mercury and toxics, (c) provide source-receptor, sensitivity, and process analyses and (d) be computationally efficient and easy to use.

The U.S. EPA has approved the use of CAMx for numerous ozone and PM State Implementation Plans throughout the U.S. and has used this model to evaluate regional mitigation strategies including those for most recent national transport rules, such as the Cross-State Air Pollution Rule (CSAPR), CSAPR Update, and the modeling used in justification of denial of the MPCA SIP. The MPCA used Version 6.4, which was released in December 2016. Unlike some of EPA's previous ozone modeling guidance that specified a particular ozone model (e.g., EPA 1991 Guidance[63]) or that specified the Urban Airshed Model (UAM)[64], the EPA now recommends that

[62] User's Guide: Comprehensive Air Quality Model with Extensions version 6.40. Novato, CA. http://www.camx.com/files/camxusersguide_v6-40.pdf

[63] Draft Guidance on the Use of Models and Other Analyses in Attainment Demonstrations for the 8-hr Ozone NAAQS". U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, N.C. May.

[64] User's Guide for the Urban Airshed Model. Volume I: User's Manual for UAM (CB-IV) prepared for the U.S. Environmental Protection Agency (EPA-450/4-90-007a). Systems Applications International, San Rafael, CA.

models be selected for ozone SIP studies on a "case-by-case" basis. The latest EPA ozone guidance[65] (pp. 24) explicitly mentions the CAMx PGMs as one of the most commonly used PGMs that would satisfy EPA's selection criteria but notes that this is not an exhaustive list and does not imply that it is "preferred" over other PGMs that could also be considered and used with appropriate justification.

The CAMx model is updated regularly to both update the science in the model and to address coding errors (bugs) in the code. CAMx 6.5 was released at the end of April 2018, approximately 6 months prior to submission the MPCA SIP submission. It is customary for regulatory modeling to "freeze" the model version during the modeling process to keep the modeling on schedule.

It is Alpine's opinion that the CAMx 6.4 air quality model along with the EPA EN platform with 2023 EGU's updated to include ERTAC was appropriate for use in the MPCA SIP.

4. Model Performance

MPCA relied on the model performance evaluation (MPE) conducted by the U.S. EPA on the modeling platform that we used for this study[66] to establish validity in the modeling platform. In addition to the MPE for the base year CAMx simulation, the U.S. EPA reported full MPE results for the 2011 WRF modeling[67] used in the CAMx simulations.

It is Alpine's opinion that the EPA WRF and CAMx performance evaluations showed adequate performance and that the modeling was appropriate for use in the MPCA SIP.

5. Source Apportionment

MPCA used the CAMx Anthropogenic Precursor Culpability Assessment (APCA) tool to calculate emissions tracers for identifying upwind sources of ozone at downwind monitoring sites. MPCA

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[65] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, an Regional Haze. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Air Assessment Division. Research Triangle Park, NC. EPA 454/R-18-009. November 29. (https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf).

[66] US EPA. 2016. Air Quality Modeling Technical Support Document for the 2015 Ozone NAAQS Preliminary Interstate Transport Assessment. Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2017-01/documents/aq_modeling_tsd_2015_o3_naaqs_preliminary_interstate_transport_assessmen.pdf

[67] US EPA. 2014. Meteorological Model Performance for Annual 2011 WRFv3.4 Simulation. Research Triangle Park, NC. https://www3.epa.gov/ttn/scram/reports/MET_TSD_2011_final_11-26-14.pdf.

used the APCA technique because it more appropriately associates ozone formation to anthropogenic sources than the CAMx Ozone Source Apportionment Technique (OSAT). If any anthropogenic emissions are involved in a reaction that leads to ozone formation, even if the reaction occurs with biogenic VOC or NOx, APCA tags the ozone as anthropogenic in origin.

The APCA source apportionment tool has a robust theoretical basis and a long application history and it is our opinion that the APCA tool is appropriate for identifying upwind sources of ozone at downwind monitoring sites.

6. Interstate Transport Provisions – Section 110(a)(2)(D)

This section of the CAA requires SIPs to have provisions prohibiting sources from emitting air pollutants in amounts that would contribute significantly to nonattainment or interfere with maintenance in any other state. These interstate transport requirements are often referred to as “good neighbor SIPs”. The analyses conducted both by LADCO and EPA to support the 2015 ozone good neighbor SIPs show Minnesota does not contribute significantly to air quality problems in any downwind nonattainment or maintenance area. Therefore, no additional controls or emissions limits were required to fulfill Minnesota’s good neighbor obligations.

On March 27, 2018, the EPA published a memo, entitled “Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I)”. EPA’s Memo included new transport modeling data for the year 2023 (the Moderate Attainment deadline for the 2015 ozone NAAQS). These data are provided to assist states in completing the “good neighbor” SIPs for the 2015 ozone NAAQS, and to thereby address interstate transport obligations.

EPA identifies a four-step framework in the Memo, intended to guide states on how to go about developing good neighbor SIPs:

1. Identify downwind air quality problems;
2. Identify upwind states that contribute enough to those downwind air quality problems to warrant further review and analysis;
3. Identify the emissions reductions necessary (if any), considering cost and air quality factors, to prevent an identified upwind state from contributing significantly to those downwind air quality problems; and
4. Adopt permanent and enforceable measures needed to achieve those emissions reductions.

In Step 1, EPA identifies monitoring sites that are projected to have problems attaining and/or maintaining the NAAQS in the 2023 analytic year. Where EPA’s analysis shows that a site does not fall under the definition of a nonattainment or maintenance receptor, that site is excluded from further analysis under EPA's 4-step interstate transport framework. For sites that are identified as a nonattainment or maintenance receptor in 2023, we proceed to the next step of our 4-step interstate transport framework by identifying the upwind state's contribution to those receptors.

In Step 2, EPA quantifies the contribution of each upwind state to each receptor in the 2023 analytic year. The contribution metric used in Step 2 is defined as the average impact from each state to each receptor on the days with the highest ozone concentrations at the receptor based on the 2023 modeling. If a state's contribution value does not equal or exceed the threshold of 1 percent of the NAAQS (i.e., 0.70 ppb for the 2015 ozone NAAQS), the upwind state is not ''linked'' to a downwind air quality problem, and EPA, therefore, concludes that the state does not significantly contribute to nonattainment or interfere with maintenance of the NAAQS in the downwind states.

Comparably, in MPCA's SIP submission, they include LADCO's modeling which additionally follows the same transport framework and is corroborated by EPA's modeling with the data released with the March 2018 memo.

Step 1 - 2023 Air Quality Projections

MPCA's reported air quality projections[68] submitted with their SIP were based on the ozone modeling conducted by LADCO. The result of this LADCO 2023 modeling, using methods utilized by EPA and shown in Table 9 below, forecasted that no downwind monitors in the Midwest or Northeast would be nonattainment for the 2015 O3 NAAQS.

[68] Data source Table 5, Attachment 1, EPA-R05-OAR-2018-0689-0003

			LADCO 2023 DV		2009-2013 DV	
AQS ID	**County**	**ST**	**3x3 Avg**	**3x3 Max**	**3x3 Avg**	**3x3 Max**
90010017	Fairfield	CT	67.2	69.4	78.0	80.0
90013007	Fairfield	CT	67.8	71.6	84.3	89.0
90019003	Fairfield	CT	69.6	72.4	83.7	87.0
90099002	New Haven	CT	67.9	70.5	85.7	89.0
240251001	Harford	MD	69.4	71.8	90.0	93.0
260050003	Allegan	MI	67.1	69.8	80.3	83.0
261630019	Wayne	MI	67.7	69.7	78.7	81.0
360810124	Queens	NY	67.5	69.2	70.0	71.0
361030002	Suffolk	NY	69.8	71.3	83.3	85.0
550790085	Milwaukee	WI	62.1	65.1	78.3	82.0
551170006	Sheboygan	WI	69.3	71.5	84.3	87.0

Table 9. LADCO 2023 ozone design values at EPA identified nonattainment and maintenance monitors in the Midwest and Northeast.

EPA's own modeling[69], released with the March 2018 platform, shown in Table 10, and designed to be used by states in development of their ozone transport SIPs, indicated that in the Midwest or Northeast, two downwind monitors in Fairfield, Connecticut (monitors 90013007 and 90019003), a monitor in Suffolk, New York (36103002), and monitors in Milwaukee (550790085) and Sheboygan (551170006), Wisconsin would be in nonattainment for the 2015 ozone NAAQS.

			EPA 2023 DV		2009-2013 DV	
AQS ID	**County**	**ST**	**3x3 Avg**	**3x3 Max**	**3x3 Avg**	**3x3 Max**
90010017	Fairfield	CT	68.9	71.2	80.3	83.0
90013007	Fairfield	CT	71.0	75.0	84.3	89.0
90019003	Fairfield	CT	73.0	75.9	83.7	87.0
90099002	New Haven	CT	69.9	72.6	85.7	89.0
240251001	Harford	MD	70.9	73.3	90.0	93.0
260050003	Allegan	MI	69.0	71.7	82.7	86.0
261630019	Wayne	MI	69.0	71.0	78.7	81.0
360810124	Queens	NY	70.2	72.0	78.0	80.0
361030002	Suffolk	NY	74.0	75.5	83.3	85.0
550790085	Milwaukee	WI	71.2	73.0	80.0	82.0
551170006	Sheboygan	WI	72.8	75.1	84.3	87.0

Table 10. EPA 2023 ozone design values at nonattainment and maintenance monitors in the Midwest and Northeast.

[69] https://www.epa.gov/sites/default/files/2018-05/updated_2023_modeling_dvs_collective_contributions.xlsx

An additional six monitors in Connecticut (90010017 and 90099002), Maryland (240251001), Michigan (260050003 and 261630019), and New York (360810124) would be considered maintenance monitors in the projection.

In neither the LADCO nor EPA modeling cited in MPCA's SIP revision submission were the two Cook County, Illinois monitors (170314201 and 170310076) from EPA's SIP denial NPR, or the single monitor from EPA's final SIP disapproval action, identified as either nonattainment or maintenance monitors in the 2023 projections.

Step 2 - Significant Contribution to Downwind States

EPA has previously determined that a state contribution to downwind air quality problems below one percent of the applicable NAAQS is insignificant. This screening method was used in previous good neighbor SIP approvals, and other regulatory actions including (most notably) the Cross-State Air Pollution Rule (CSAPR), and the CSAPR update for the 2008 ozone NAAQS and 2012 NAAQS for particulate matter less than 2.5 micrometers in diameter (PM2.5). The one percent screening method was developed through several previous federal notice and comment rulemakings. One percent of the 2015 ozone NAAQS (70 ppb) is 0.70 ppb. Therefore, any state that contributes less than 0.70 ppb to a projected nonattainment or maintenance area in another state is not culpable for those air quality problems.

EPA and LADCO applied the Anthropogenic Precursor Culpability Analysis (APCA) technique in CAMx to identify upwind states culpable for downwind ozone air quality problems. The method accounts for anthropogenic nitrogen oxides (NO_x) and volatile organic carbon (VOC) emissions from all sources in each upwind state affecting projected 2023 ozone concentrations at each downwind air quality monitoring site designated a nonattainment or maintenance receptor. EPA and LADCO conducted the culpability analysis for the period May 1 through September 30, using the 2023 future emission estimates and 2011 meteorology.

Both LADCO and EPA analyses[70] conclude Minnesota is not culpable for ozone nonattainment, or interference with maintenance, in any downwind states. As shown in Table 11, prepared using data from MPCA's SIP[71], LADCO's analysis shows a maximum contribution of 0.45 ppb to the identified maintenance monitors, less than the 0.70 ppb identified as 1% of the NAAQS (70 ppb). EPA's analysis[72] (Table 12) indicates Minnesota contributes most to Milwaukee, Wisconsin monitor site 550790085. At a concentration of 0.40 ppb, this contribution is roughly equal to 0.57% of the 2015 ozone NAAQS.

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[70] Data source Table 2, EPA-R05-OAR-2018-0689-0003

[71] Id.

[72] Id.

AQS ID	County	ST	2023 Avg DV	2023 Max DV	MN Contribution (ppb)
90010017	Fairfield	CT	67.2	69.4	0.17
90013007	Fairfield	CT	67.8	71.6	0.15
90019003	Fairfield	CT	69.6	72.4	0.11
90099002	New Haven	CT	67.9	70.5	0.16
240251001	Harford	MD	69.4	71.8	0.12
260050003	Allegan	MI	67.1	69.8	0.11
261630019	Wayne	MI	67.7	69.7	0.30
360810124	Queens	NY	67.5	69.2	0.16
361030002	Suffolk	NY	69.8	71.3	0.16
550790085	Milwaukee	WI	62.1	65.1	0.45
551170006	Sheboygan	WI	69.3	71.5	0.27

Table 11. LADCO 2023 O3 design values at nonattainment and maintenance monitors in the Midwest and Northeast and Minnesota's calculated contribution.

AQS ID	County	ST	2023 Avg DV	2023 Max DV	MN Contribution (ppb)
90010017	Fairfield	CT	68.9	71.2	0.17
90013007	Fairfield	CT	71.0	75.0	0.15
90019003	Fairfield	CT	73.0	75.9	0.14
90099002	New Haven	CT	69.9	72.6	0.19
240251001	Harford	MD	70.9	73.3	0.13
260050003	Allegan	MI	69.0	71.7	0.11
261630019	Wayne	MI	69.0	71.0	0.31
360810124	Queens	NY	70.2	72.0	0.17
361030002	Suffolk	NY	74.0	75.5	0.18
550790085	Milwaukee	WI	71.2	73.0	0.40
551170006	Sheboygan	WI	72.8	75.1	0.28

Table 12. EPA 2023 O3 design values at nonattainment and maintenance monitors in the Midwest and Northeast and Minnesota's calculated contribution.

For the reasons set forth in this section, it is our opinion that the modeling conducted and cited by MPCA in the development of its 2015 ozone NAAQS transport SIP revision of October 2018 was technically adequate and appropriate for the purpose it was intended and followed all available EPA guidance on preparing technical modeling for SIP and SIP-related analyses.

Additionally, in our opinion, the MPCA SIP adequately demonstrates that Minnesota is not a significant contributor to any downwind monitor identified as in nonattainment or maintenance for the 2015 ozone NAAQS and is corroborated by EPA modeling which included state-of-science configuration and platform at the time the original SIP was submitted.

D. Summary of Conclusions

For the reasons set forth in this document, it is our opinion that the modeling conducted and cited by MPCA in the development of its 2015 ozone NAAQS transport SIP revision of October 1, 2018 was technically adequate and appropriate for the purpose it was intended and should have been approved by EPA at the time of submission. It is further our opinion that decisions made by EPA to compare MPCA's original submitted modeling to recently updated modeling, developed by EPA over four years and four months later than the original Oct 2018 submission, are inconsistent with EPA precedent.

It is our opinion that in the absence of inclusion of Minnesota's and other stakeholder's valid emission modeling platform revision submissions, as requested by EPA, and multiple reruns of the air quality in both the base year (2016) and projection year (2023) simulations, EPA cannot appropriately identify monitors as nonattainment or maintenance, and in turn, cannot calculate upwind state significant contribution metrics from these same data. Non-EGU emission controls and their associated NOx emission reductions as documented and submitted by MPCA, could be enough to change nonattainment designations and linked significance using an updated platform and needs to be considered before making any final decision on denial of MPCA's SIP.

It is our opinion that EPA's use of modeling with poor performance at critical monitors amounts to an unreliable result when used to establish nonattainment or maintenance monitors under Step 1 or linkages under Step 2 of the 4-step framework. Should more refined modeling be undertaken to review the ozone formation potential at monitors located in these land-water interfaces, results may show that these monitors demonstrate modeled attainment and/or remove significant contribution linkages from upwind states.

It is our opinion that the most recent modeling cited by EPA and used to justify the linkage of Minnesota to one downwind maintenance monitors in Cook County, Illinois has technical issues as it relates to that linked monitor which is located in a complex land-water interface and may require finer grid resolution modeling to adequately capture ozone formation and significant contribution, and that EPA must address the impact of VOC emissions in influencing ozone formation at monitors in Illinois.

It is our opinion that EPA has failed to follow the process by relying on the best available modeling at the time that an analysis is conducted, and results are developed and submitted. Instead, EPA continues to move the target and objectives for states that, in Minnesota's case, for over four years had been waiting for a review of their "best available data and analysis".

It is our opinion that EPA should not have used any updated modeling to support a SIP review while not providing the opportunity for that data to be reviewed, analyzed, and commented on in advance of any final decision on the subject SIP disapproval and that any modeling beyond what was conducted in the original SIP submittal was ancillary to the approval process. However, should EPA decide not to review MPCA's SIP revision on its merit, Alpine recommends that EPA withdraw the SIP disapproval in favor of correcting the technical errors that have been identified in its analysis and to propose an appropriate opportunity for Minnesota to address any deficiencies EPA may find in Good Neighbor Plans implementing the 2015 ozone NAAQS.

It is our opinion that EPA's 2018 flexibility memo has become so instrumental to states in developing their good neighbor SIPs, that EPA's decision to disallow the flexibilities that they themselves outlined in guidance, is unreasonable and should be reconsidered.

Additionally, in our opinion, the MPCA SIP adequately demonstrates that Minnesota is not a significant contributor to any downwind monitor identified as in nonattainment or maintenance for the 2015 ozone NAAQS and is corroborated by EPA modeling which included state-of-science configuration and platform at the time the original SIP was submitted. It is our opinion that the original MPCA SIP was and is approvable.

E. Minnesota 2015 Ozone SIP Timeline

October 1, 2015 – EPA finalized the revised 2015 ozone NAAQS. Pursuant to CAA section 110(a)(1), "each state shall . . . submit to the Administrator, within 3 years. . .after promulgation of a [primary NAAQS] (or any revision thereof) a plan which provides for implementation, maintenance, and enforcement of such primary standard. . ." CAA section 110(a)(2)(D)(i)(I) requires such SIPs to "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, and other State with respect to such NAAQS.

March 27, 2018 - EPA published a memo, entitled "Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I)". EPA's Memo included new transport modeling data for the year 2023 (the Moderate Attainment deadline for the 2015 ozone NAAQS). These data are provided to assist states in completing the "good neighbor" SIPs for the 2015 ozone NAAQS, and to thereby address interstate transport obligations.

October 1, 2018 - Minnesota Pollution Control Agency (MPCA) submitted a SIP revision to address CAA Section 110(a)(2)(D)(i)(I) on October 1, 2018 .[73] The submission met the statutory deadline for submittal the interest transport SIPs for the 2015 ozone NAAQS. The submission utilized both EPA modeling released with the March 2018 memorandum and LADCO modeling results previously mentioned. Minnesota followed the 4-step interstate transport framework and used an analytic year of 2023 to describe Minnesota's lack of contributions to out of state receptors and assess emission reduction considerations.

April 1, 2019 – This is 6 months after EPA received the Minnesota SIP submission and is the date that the CAA deems the Minnesota submittal to have been complete since EPA did not take action otherwise.

September 13, 2019 - The D.C. Circuit issued a decision in *Wisconsin v. EPA*, remanding the CSAPR Update to the extent that it failed to require upwind states to eliminate their significant

[73] **Completeness Finding** - Pursuant to the CAA Section 110(k)(1)(B) "Within 60 days of the Administrator's receipt of a plan or plan revision, but no later than 6 months after the date, if any, by which a State is required to submit the plan or revision, the Administrator shall determine whether the minimum criteria established pursuant to subparagraph (A) have been met. Any plan or plan revision that a State submits to the Administrator, and that has not been determined by the Administrator (by the date 6 months after receipt of the submission) to have failed to meet the minimum criteria established pursuant to subparagraph (a), shall on that date be deemed by operation of law to meet such minimum criteria."

contribution by the next applicable attainment date by which downwind states must come into compliance with the NAAQS, as established under CAA section 181(a). 938 F.3d at 313.

April 1, 2020 – This is 12 months after the completeness date and is the deadline for EPA to have acted on the MN SIP submission. Upon this deadline a full, partial or conditional approval was required by CAA Section 110(k)(2), (3), or (4).[74]

May 19, 2020 - the D.C. Circuit issued a decision in *Maryland v. EPA* that cited the Wisconsin decision in holding that EPA must assess the impact of interstate transport on air quality at the next downwind attainment date, including Marginal area attainment dates, in evaluating the basis for EPA's denial of a petition under CAA section 126(b). Maryland v. EPA, 958 F.3d 1185, 1203-04 (D.C. Cir. 2020). The court noted that "section 126(b) incorporates the Good Neighbor Provision," and, therefore, "EPA must find a violation [of section 126] if an upwind source will significantly contribute to downwind nonattainment at the next downwind attainment deadline. Therefore, the agency must evaluate downwind air quality at that deadline, not at some later date." Id. at 1204 (emphasis added). EPA interprets the court's holding in Maryland as requiring the states and the Agency, under the good neighbor provision, to assess downwind air quality as expeditiously as practicable and no later than the next applicable attainment date, which is now the Moderate area attainment date under CAA section 181 for ozone nonattainment. The Moderate area attainment date for the 2015 ozone NAAQS is August 3, 2024. At the time of the statutory deadline to submit interstate transport SIPs (October 1, 2018), many states relied upon EPA modeling of the year 2023, and no state provided an alternative analysis using a 2021 analytic year (or the prior 2020 ozone season). However, EPA must act on SIP submittals using the information available at the time it takes such action. In this circumstance, EPA does not believe it would be appropriate to evaluate states' obligations under CAA section 110(a)(2)(D)(i)(I) as of an attainment date that is wholly in the past, because the Agency interprets the interstate transport provision as forward looking. See 86 FR at 23074; see also Wisconsin, 938 F.3d at 322. Consequently, in this proposal EPA will use the analytical year of 2023 to evaluate each state's CAA section 110(a)(2)(D)(i)(I) SIP submission with respect to the 2015 ozone NAAQS.

May 12, 2021 – Downwinders at Risk, et al filed Case No. 21 Civ. 21 Civ 3551 asserting that EPA failed to undertake certain non-discretionary duties under the CAA.

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[74] **Deadline for Action**. – Pursuant to the CAA Section 110(k)(1)(B) "Within 12 months of a determination by the Administrator (or a determination deemed by operation of law) under paragraph (1) that a State has submitted a plan or plan revision (or, in the Administrator's discretion, part thereof) that meets the minimum criteria established pursuant to paragraph (1), if applicable (or, if those criteria are not applicable, within 12 months of submission of the plan or revision), the Administrator shall act on the submission in accordance with paragraph (3)."

February 22, 2022 - EPA assessed the Minnesota submittal and on February 22, 2022 (3 years, 4+ months after submittal) the agency proposed denial of the Minnesota SIP as follows: "Based on EPA's evaluation of Minnesota's SIP submission and after consideration of updated EPA modeling using the 2016-based emissions modeling platform, EPA is proposing to find that the portion of Minnesota's October 1, 2018 SIP submission addressing CAA section 110(a)(2)(D)(i)(I) does not meet the state's interstate transport obligations for 2015 ozone NAAQS, because it fails to contain the necessary provisions to eliminate emissions that will contribute significantly to nonattainment or interfere with maintenance of the NAAQS in any other state. Air Plan Disapproval; Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin; Air Plan Disapproval; Region 5 Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 87 Fed. Reg. 9838 (Feb. 22, 2022).

February 28, 2022 – EPA and Downwinders et al established in a Consent Decree entered into on 1/12/2022 that if EPA proposed a full or partial denial of the Minnesota SIP EPA shall have until December 15, 2022 to sign a final action. Note this is a settlement and does not erase the fact that EPA failed to complete its non-discretionary duty to have reviewed and acted upon the MN SIP by April 1, 2020.

April 30, 2022 – EPA and Downwinders, et established in a Consent Decree entered into on 1/12/2022 that required EPA to sign for publication final rulemaking on April 30, 2022 to approve, disapprove, and conditionally approve the Minnesota SIP submissions for the 2015 ozone NAAQS.

May 22, 2022 – EPA proposed to approve most elements of the Minnesota October 1, 2018 submission intended to address all applicable infrastructure requirements for the 2015 NAAQS. (87 FR 31462).

July 29, 2022 – EPA approved most elements of the Minnesota October 1, 2018 SIP submission from Minnesota regarding infrastructure requirements for the 2015 ozone NAAQS. EPA did not act on the interstate transport requirements and visibility impairments requirements. (87 FR 45663).

December 8, 2022 – EPA and Downwinders et al filed a Joint Motion of Stipulated Extension of Consent Decree deadlines that provided the following schedule.

December 15, 2022 – Former agreed upon deadline by Downwinders for EPA to act on Minnesota SIP, but this deadline was moved by agreement to January 31, 2022.

January 31, 2023 - deadline to sign final action on Minnesota SIP pursuant to agreed upon extension of Downwinders Consent Decree.

February 13, 2023 – EPA publishes final disapproval of State Implementation Plan (SIP) submissions for 19 states, including Minnesota. Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 FR 9336.

March 15, 2023 – EPA issues final federal Good Neighbor Plan for the 2015 ozone NAAQS (publication in the Federal Register is still pending).

IN THE UNITED STATES CIRCUIT COURT
FOR THE DISTRICT OF COLUMBIA CIRCUIT

UNITED STATES STEEL CORPORATION, Petitioner v. UNITED STATES EVIRONMENTAL PROTECTION AGENCY, and MICHAEL S. REGAN, Administrator, U.S. EPA, Respondents.	Case No. 23-1207 Consolidated with Case Nos. 23-1157 (lead), 23-1181, 23-1183, 23-1190, 23-1191, 23-1193, 23-1195, 23-1199, 23-1200, 23-1201, 23-1202, 23-1203, 23-1205, 23-1206, 23-1208, 23-1209, and 23-1211

Declaration of Alexis Piscitelli in Support of
United States Steel Corporation's Motion for Stay

I, Alexis Piscitelli, am over 18 years of age and make the following declaration pursuant to 28 U.S.C. § 1746:

1. I am the Senior Director Environmental for North American Flat Roll. at United States Steel Corporation ("U. S. Steel"), where I am responsible for ensuring compliance and reporting requirements are met in accordance with federal, state and local environmental permits and regulations. I have been employed by U. S. Steel for over 26 years and have advanced through various positions.

2. I am providing this declaration on behalf of U. S. Steel's Motion for Stay of the United States Environmental Protection Agency's ("EPA's") Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality

Standards ("Good Neighbor Plan" or "Final Rule"), 88 Fed. Re. 36,654 (June 5, 2023).

3. As further explained in this declaration, the Final Rule will require immediate actions by U. S. Steel, including either curtailing the operation of reheat furnaces and boilers at U. S. Steel, or the expenditure of millions of dollars to prepare now for implementation of the Good Neighbor Plan. Either or both of these actions will impose significant additional cost on U. S. Steel. Curtailing or the potential shutdown of the reheat furnaces would impact downstream units and ultimately customers. Curtailing the boilers will reduce electricity generation and increase the demand for outside purchased power, increasing costs and putting additional strain on the grid.

4. The Good Neighbor Plan also omits important flexibilities U. S. Steel uses to effectively and efficiently manage its environmental obligations.

5. This declaration is based on my personal knowledge of facts and information pertaining to U. S. Steel's business and the implications of EPA's Good Neighbor Plan. My knowledge is based on my history with U. S. Steel and analysis U. S. Steel has conducted of the Good Neighbor Plan.

I. The Implementation Schedule for the Good Neighbor Plan is Insufficient

6. In response to the Good Neighbor Plan, U. S. Steel developed a schedule for compliance with the regulatory obligations applicable to U. S. Steel – Gary Works' 84" Hot Strip Mill.

7. Based on our experience with projects of similar size and complexity, the assessment, design, permitting, and installation of low-NOx burners at all four furnaces will not be complete until May 2027, over a year beyond the May 2026 deadline for certification of completion of installation of low-NOx technology in the Good Neighbor Plan. A copy of the project schedule is included as Appendix A to the attached Barr report (Attachment 1).

8. This schedule conservatively assumes that permitting can be completed in six months. Based on my experience, permitting can take significantly longer, leading to additional delays in completion.

9. U. S. Steel has also had difficulty obtaining vendor quotes for the required work. Consistent with U. S. Steel practice, our contractor, Barr, has attempted to obtain three separate vendor quotes for each technology U. S. Steel is analyzing. Only two firms provided full responses as of July 7, 2023. For one technology, selective non-catalytic reduction ("SNCR"), Barr contacted at least eight vendors but was able to obtain only two estimates. This further demonstrates the need for additional time for

implementation of the Good Neighbor Plan, as we anticipate vendors will continue to experience backlogs and supply chain disruptions.

10. U. S. Steel has also had difficulty finding and scheduling qualified union contractors to work on significant projects at our facilities. For example, there are four reheat furnaces at Gary, each will require a significant outage to retrofit the equipment with low NOx burners or the equivalent. We anticipate the availability of qualified union workers will become even a larger issue with multiple sources being impacted by the Good Neighbor Plan.

II. Implementation of the Good Neighbor Plan Requires U. S. Steel to Incur Immediate and Significant Costs

11. Among other things, the Good Neighbor Plan as promulgated imposes requirements on certain reheat furnaces at iron and steel mills, including the requirement to design a low-NOx burner or alternative low-NOx technology to achieve NOx emission reductions of at least 40% from baseline emission levels measured during performance testing that meets the criteria set forth in the rule. Additional obligations include emissions monitoring, recordkeeping, and reporting requirements.

12. While I agree that requiring a universal, hard limit for reheat furnaces is not appropriate, the requirement to design to meet a minimum 40% reduction of NOx from baseline is not appropriate because it does not take into account

what is achievable for each reheat furnace, including what the baseline value actually is – whether, for example, it is 0.12 lb/MMBtu or 0.24 lb/MMBtu, what limits there are on the type of NOx reduction technology that can be used, what fuels the reheat furnace uses, what other pollution control technologies are already in place, or other factors that may make a minimum 40% reduction on some units technically or economically infeasible.

13. Baseline emission level performance testing cannot be completed without significant modification. For example, the reheat furnaces at Gary are very difficult to access. Testing equipment required to meet the USEPA specification cannot be used as currently configured. The facility will require engineered modification to provide access for personnel and equipment to conduct the required testing to establish a baseline for at least a 40% reduction design.

14. Based on the deadlines in the Good Neighbor Plan, which include submitting a completed work plan by August 5, 2024, U. S. Steel has already needed to begin project engineering and design and is already incurring significant costs to complete this work. Without a stay, and while the rule is subject to petitions for review, these costs are expected to substantially

increase in the coming months with EPA's aggressive rule implementation schedule.

15. Based on an initial assessment of the costs supported by vendor quotes, I estimate installing low-NOx burners at the four reheat furnaces at U. S. Steel – Gary Works' 84" Hot Strip Mill will cost between approximately $28 million to more than $46 million. *See* Attachment 1 at Table 4-1. This does not include additional operating costs associated with the new equipment or additional monitoring, performance testing, recordkeeping, and reporting costs associated with the Good Neighbor Plan.

16. This results in an estimated cost effectiveness of between $18,300 and $42,300 per ton NOx removed. Attachment 1 at Table 4-2. This far exceeds $3,656/ton average EPA includes in its Technical Memorandum to support the Final Rule. Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, EPA-HQ-OAR-2021-0668-0956, at Table 6 (March 15, 2023). It also far exceeds EPA's marginal cost threshold of $7,500/ton, the average cost-per-ton range for all non-EGUs of $939/ton to $14,595/ton, and even the $11,000/ton representative EGU retrofit cost EPA used for comparison in the Good Neighbor Plan. Final Rule at 36,746.

17. Without the Good Neighbor Plan, U. S. Steel would not need to incur these costs.

18. To comply with the Good Neighbor Plan, U. S. Steel will need to take reheat furnaces and boilers offline while they are retrofitted. This will involve multiple outages that would be unnecessary without the Good Neighbor Plan. These outages will impact production capabilities and may lead to the flaring of by-product fuels, wasting a valuable resource.

19. A stay of the FIP is necessary to avoid these unnecessary costs and outages until a final decision is reached on what obligations should apply to reheat furnaces and boilers at iron and steel mills.

20. Without a stay, U. S. Steel will incur significant and irreparable harm in reconfiguring the hot strip mill at Gary Works to allow for baseline performance testing and implementing the rule's requirements at the Company.

III. **The Cumulative Burdens of the Good Neighbor Plan and Other Federal Requirements will Be Substantial and Could Have a Material Impact on Critical Infrastructure, National Security, and U. S. Steel Operations.**

21. The U.S. steel industry is responsible for over $520 billion in economic output, supporting over 2 million jobs. It generates over $56 billion in tax revenues annually.

22. In a study conducted under Section 232 of the Trade Expansion Act of 1962 (19 U.S.C. §1862), the U.S. Department of Commerce determined that domestic steel production is essential for national security; and that domestic

steel production depends on a healthy and competitive U.S. industry. (*See* https://www.bis.doc.gov/index.php/other-areas/office-of-technology-evaluation-ote/section-232-investigations).

23. The Cybersecurity & Infrastructure Security Agency has identified the iron and steel industry as a core critical infrastructure industry impacting transportation systems, electric power grid, water systems, and energy generation systems. (*See* https://www.cisa.gov/topics/critical-infrastructure-security-and-resilience/critical-infrastructure-sectors/critical-manufacturing-sector).

24. Implementation of the Final Rule upon the steel industry, when at the same time implementing new rules upon all facets of domestic steel manufacturing also potentially jeopardizes thousands of good-paying USW jobs.

25. U. S. Steel is committed to continuing to work with federal partners to develop and implement scientifically sound regulations that effectively and demonstrably benefit the environment.

26. EPA's promulgation of overlapping Clean Air Act regulations without adequate consideration of their interaction undermines these efforts.

27. At the same time that EPA promulgated the Good Neighbor Plan, where it is mandating the installation of controls at reheat furnaces and boilers at iron

and steel mills, EPA is proposing new MACT standards at taconite, integrated iron and steel facilities, and coke plants; as well as proposing revised NAAQS standards (e.g., PM2.5) which, combined, could have a material impact on the domestic steel industry, significantly affect the schedule for achieving these requirements, and result in a shortage of available technical support for implementation of these rules.

28. As noted above, U. S. Steel is already having difficulty obtaining qualified contractors and vendor quotes. These additional rules will exacerbate the problem.

29. EPA has also announced that it anticipates proposing reconsideration of the current ozone NAAQS in April 2024. As a result, EPA may be revising the ozone NAAQS at the same time that the Good Neighbor Plan is requiring U. S. Steel to install pollution controls to address the current standards. Piecemealing these two rules, for which implementation will likely overlap, is problematic and inappropriate, as U. S. Steel could quite possibly be compelled to install additional or different controls on the same emission units following EPA's reconsideration. This would result in significant waste and could be avoided if EPA withdraws the Good Neighbor Plan and takes the two years allowed by the Clean Air Act for implementation of a revised FIP.

IV. Conclusion

30. In my opinion, the schedule set forth in the Good Neighbor Plan is not realistic and underestimates the time needed for compliance by at least a year. If emission units cannot achieve compliance by the scheduled deadlines and the deadlines are not stayed or extended, those emission units will be required to curtail operation. As a result. U. S. Steel is already required to incur substantial costs in order to prepare for the upcoming Good Neighbor Plan deadlines despite pending petitions for reconsideration and judicial review that may affect the applicability of the Good Neighbor Plan and the obligations that it imposes on reheat furnaces and boilers.

31. A stay of the Good Neighbor Plan will mitigate these harms.

I declare, under penalty of perjury, that the foregoing is true and correct. Executed on August 22, 2023.

Alexis Piscitelli
Sr. Director Environmental – NAFR
United States Steel Corporation

ATTACHMENT 1

resourceful. naturally.
engineering and environmental consultants

Technical Memorandum

To: Louis Covelli (U. S. Steel)
From: Dane Jensen
Subject: 84" Hot Strip Mill Reheat Furnaces Good Neighbor Plan NO_X Emissions Controls Evaluation
Date: August 3, 2023
Project: 14451044.00
c: Thomas Ruffner, David Hacker, Kendra Jones, Christopher Hardin, Brett Tunno (U. S. Steel), Ryan Siats (Barr Engineering Co.)

Executive Summary

The U.S. Environmental Protection Agency (EPA) is taking action under the "good neighbor" or "interstate transport" provision of the Clean Air Act, with rulemaking that will take effect on August 4, 2023. The Good Neighbor Plan rulemaking under Docket ID No. EPA–HQ–OAR–2021-0668 requires emission reductions for affected facilities at U. S. Steel – Gary Works (USS), namely the 84" Hot Strip Mill (HSM) reheat furnaces (RHFs). The draft rulemaking requires a 40% NO_X reduction for RHFs. Barr was tasked with assessing the technical feasibility of selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) technologies, reviewing facility impacts of feasible NO_X controls including Low NO_X Burners (LNB), estimating costs and the cost effectiveness of feasible NO_X controls, and summarizing annual compliance testing costs.

The key findings of the HSM NO_X evaluation include:

- SCR is not technically feasible for the RHFs.
- SNCR is not technically feasible for the RHFs. There are operating conditions where the flue gas temperatures are expected to be outside the required SNCR reaction range.
- The compliance schedule in the draft rulemaking is insufficient to allow for installation of NO_X control technologies given requirements for baseline emissions testing, permitting, and availability of equipment vendors, mill wrights, engineering staff, etc.
- LNBs would require furnace upgrades, new flame safety equipment, and other facility modifications to accommodate this technology.
- The cost effectiveness of LNBs ranges from \$18,300 to \$42,300 per ton of NO_X removed.
- Annual performance testing costs for the RHFs are estimated to be \$13,300 to comply with the monitoring requirements of the Good Neighbor Plan.

Additional detail on each finding is summarized by Section below.

1 Good Neighbor Rule Regulatory Applicability

The regulatory applicability of the RHFs to the Good Neighbor Plan is described below.

40 CFR 52.43(b) states "*The requirements of this section apply to each new or existing reheat furnace at an iron and steel mill or ferroalloy manufacturing facility that directly emits or has the potential to emit 100 tons per year or more of NO_X on or after August 4, 2023, does not have low-NO_X burners installed, and is located within any of the States listed in § 52.40(c)(2), including Indian country located within the borders of any such State(s).*" The four reheat furnaces located at the Gary Works HSM all exceed a 100 tpy NO_X potential to emit, are in a state listed in §52.40(c)(2), and do not have LNB installed. Therefore, the RHFs are subject to the provisions of 40 CFR 52.43 and must achieve a 40% NO_X reduction from baseline conditions by the 2026 ozone season.

2 Technical Feasibility of SNCR and SCR

The technical feasibility of SNCR and SCR for the RHFs is discussed below. Figure 1 marks locations #1, #2, and #3 that will be referred to in the SNCR and SCR feasibility discussions for reference.

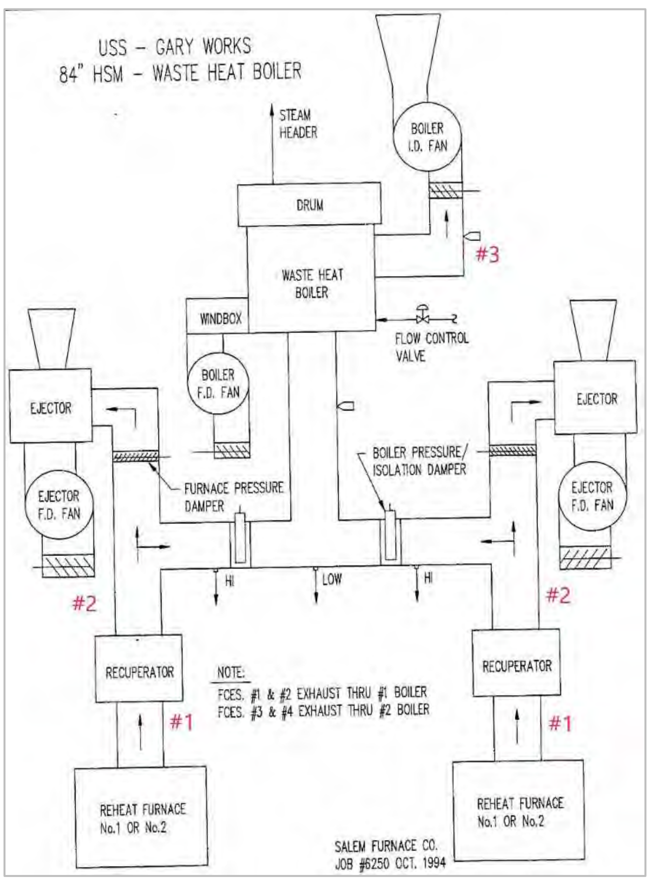

Figure 1 SNCR and SCR Feasibility Evaluation Locations

2.1 SNCR

SNCR involves the injection of ammonia or urea into a flue gas stream where the reagents react with NO_X to form elemental nitrogen. SNCR reactions require the flue gas temperature to be within a 1,600° Fahrenheit (F) to 2,100°F temperature range, with 1,800°F being ideal.

The only suitable SNCR injection location within the appropriate temperature location is #1, namely the outlet of the RHFs prior to the recuperator (refer to Figure 1). USS provided temperature data for this location and typically temperatures range from 1,600 to 1,930°F when operating. However, there are concerns about the viability of the data. A large portion of the data Barr received shows failed thermocouples or unreliable data trends. Figure 2 and Figure 3 show the Furnace 1 East and Furnace 4 East uptake temperatures, respectively, as an example of the sporadic data. It is unclear what represents "real" data vs. what is noise or failed thermocouples.

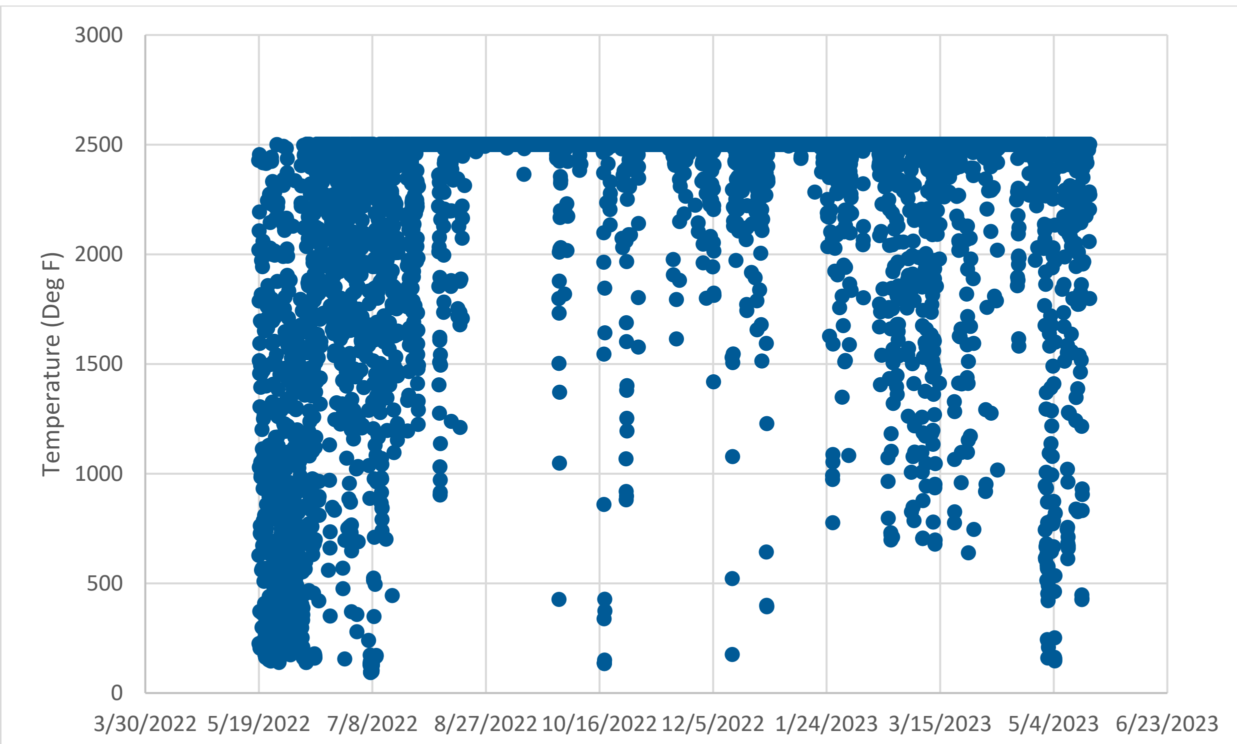

Figure 2 Furnace 1 East Uptake Temperatures Vs. Time

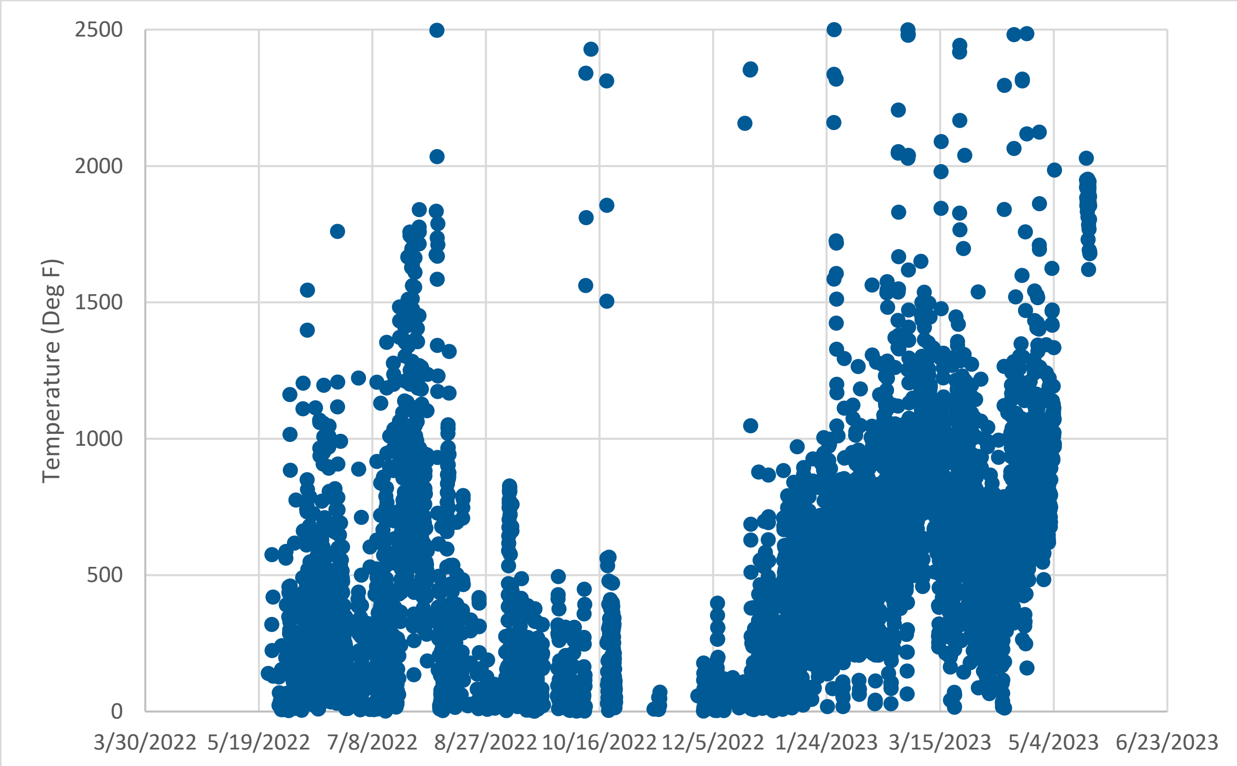

Figure 3 Furnace 4 East Uptake Temperatures Vs. Time

Another important design factor is residence time in the ducting with the high SNCR reaction temperatures. Vendors believe that there should be sufficient residence for SNCR in this application based on their review of USS data.

However, there are operating conditions where the flue gas fails to meet the minimum SNCR reaction temperatures, rendering SNCR infeasible. The Good Neighbor Plan requires a 40% NO_X reduction. Therefore, SNCR cannot sufficiently control NO_X at all times under all operating conditions. This is especially important during hot-standby conditions where fuel firing occurs, but USS expects the uptake temperatures to be below minimum SNCR requirements. In addition, a vendor stated that a feasibility study would be required to provide any sort of NO_X reduction guarantee. While SNCR is feasible during some operating scenarios, it cannot provide the needed consistent NO_X reduction for compliance purposes.

2.2 SCR

SCR reduces NO_X emissions with ammonia or urea injection in the presence of a catalyst. The catalyst enables the de- NO_X reactions to proceed at a lower temperature than SNCR. Most SCR catalysts must be at 450° F to 800° F for proper SCR operation based on vendor discussion and the EPA Control Cost Manual[1]. Each location for SCR from Figure 1 above was reviewed for SCR feasibility.

Location #1 – the temperatures at location #1 are too high (i.e., 1,600 to 1,930°F), so SCR is not technically feasible.

Location #2 – Waste heat temperatures exiting the recuperator are also too high for SCR. From May 2022 to May 2023, the average waste heat temperature was over 900°F, with temperature spikes exceeding 1,150°F. This is well above the optimal SCR range noted above. USS is aware that there are high-temperature applications of SCR on simple cycle combustion turbines in the temperature ranges of 850 to 1,000°F with vendors stating that 1,100°F would be the absolute maximum allowable temperature. However, high temperature SCR systems are significantly more costly due to special catalyst formulations and the catalyst life expectancy tends to shorten significantly, requiring more frequent changes that may inhibit production. As noted above, the high temperature spikes above 1,150°F would be above the maximum allowable temperature range making SCR infeasible for this location. In addition, high temperature SCR applications for simple cycle combustion turbines often use tempering air to reduce exhaust temperatures to suitable levels for normal SCR reaction temperatures. However, the use of tempering air is impractical for this application because the exhaust flows exiting the recuperator are quite large (i.e., more than 800,000 acfm) meaning that large amounts of make-up air would be required to sufficiently cool the exhaust flow to acceptable SCR reaction temperatures. The exhaust handling equipment cannot accommodate additional flow, and all the areas surrounding the recuperator outlet ductwork are extremely cramped with no reasonable way to incorporate additional cooling air, let alone provide sufficient residence time for mixing. In addition, tempering air would dilute the NO_X inlet concentration reducing the control equipment effectiveness. Further, SCR reactors for airflows of this magnitude are very large requiring a significant footprint. As noted above, the spacing surrounding this location is cramped, and it would be essentially impossible to shoe-horn a SCR reactor in place for this application. Also, it is not known if the existing building infrastructure could support additional weight above the furnace after the recuperator. Therefore, SCR is not technically feasible for location #2.

Location #3 – Exhaust temperatures at the exit of the waste heat boilers (WHBs) range from approximately 450 – 925°F. This mostly fits the SCR reaction temperature requirements. While the temperature profile may be satisfactory, it is impractical to install a SCR reactor at this location. Only a portion of the RHF exhaust is routed through the WHBs, meaning that the entire gas stream would not be treated. In addition, there are times when only the ejector stack is used, and no exhaust is routed through the WHBs. Therefore, there is no way to guarantee any consistent level of NO_X reduction with SCR at this location with incomplete or no RHF exhaust treatment, and would jeopardize compliance with the Good Neighbor Plan limits. Further, the variable exhaust flow through the WHBs would significantly complicate any SCR reactor design and may make it difficult to properly inject sufficient reagents and maintain proper mixing for all operating conditions. Further, spaces surrounding the outlet of the WHBs are very

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[1] https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

cramped leaving no viable location for a sizeable SCR reactor. Therefore, SCR is not practical or technically feasible for Location #3.

3 Facility Impacts of New NO_X Controls

According to discussions with vendors, LNBs will not impact production rates and burner vendors are willing to provide this guarantee. While not inherently challenging to LNBs, there are significant concerns about the schedule and the implementation period proposed in the Good Neighbor Plan (i.e., reductions must be achieved by the 2026 ozone season). As a result of this rulemaking, USS will need to conduct and obtain results from baseline emissions testing prior to submission of an application to modify the facility's operating permit to integrate either control technology. In addition, there are numerous facilities and industries nationwide that will be required to install controls for compliance. Therefore, USS is concerned that there will be insufficient resources for performance testing, permitting, engineering, equipment suppliers, equipment fabricators, and mill wrights that will allow USS to install necessary controls for compliance, much less all other affected facilities nationwide.

Schedule concerns have been evident during the development of this memo as Barr has attempted to obtain three separate vendor quotes. However, only two firms have provided costs for both LNB August 3, 2023. One LNB vendor failed to provide a quotation to USS even after stating that they could provide a new quote, so a 2020 cost estimate was scaled to 2023 dollars for this effort. This further demonstrates the need for additional time for implementation of this rule given vendor backlogs and unexpected supply chain disruptions. In addition, USS estimated a schedule based on engineering experience for the installation of LNBs (included as Appendix A to this memo) showing that there is insufficient time in the draft rule to install controls on all four RHFs and meet the compliance deadline.

Facility impacts for LNB installations are listed below:

- To accommodate new burners, USS will need to upgrade the furnace so that sufficient pressure can be maintained at the burners for safe and reliable operation.
- New National Fire Protection Association combustion safety equipment will be installed with new burners.
- Fuel pressure regulators will require modifications to increase fuel pressure at the burners.
- Some burner vendors require new combustion air fans complicating the overall design and installation.

4 Cost Estimates of New NO_X Controls

Barr and USS evaluated the costs for LNBs below for the RHFs. A detailed breakdown of capital equipment and installation costs has been prepared by USS for LNB based on vendor quotes and engineering experience. Table 4-1 summarizes capital costs for all furnaces for each vendor.

Table 4-1 Total Capital Investment Summary for LNB by Vendor (Total Cost for All Four Furnaces)

Vendor	Total HSM Capital Investment ($)
Vendor 1	$28,400,000
Vendor 2	$32,300,000
Vendor 3 (2020 Scaled Estimate)	$46,400,000

Detailed cost-effectiveness calculations for LNB are included in Appendix B. Table 4-2 summarizes the control costs for each LNB vendor.

Table 4-2 NO_X Control Cost Summary for LNB Vendors (Individual Furnace Cost)

Vendor	Total Capital Cost ($)	Annualized Cost ($/yr)	NO_X Reduction (tpy)	Cost Effectiveness ($/ton NO_X Removed)
Vendor 1	$7,112,000	$1,156,000	63	$18,300
Vendor 2	$8,073,000	$1,294,000	31	$42,300
Vendor 3 (2020 Estimate)	$11,590,000	$1,800,000	61	$29,500

5 Annual Performance Testing Cost Estimate

USS sought a performance testing bid for annual reheat furnace testing. The annual RHF performance testing costs are estimated to be $13,322. These costs and other miscellaneous costs such as recordkeeping and reported are not included in the cost-effectiveness evaluation in Appendix B.

6 Conclusions and Recommendations

The key findings of the HSM NO_X evaluation include:

- SCR is not technically feasible for the RHFs.
- SNCR is not technically feasible for the RHFs. There are operating conditions where the flue gas temperatures are expected to be outside the required SNCR reaction range.
- The compliance schedule in the draft rulemaking is insufficient to allow for installation of NO_X control technologies given requirements for baseline emissions testing, permitting, and availability of equipment vendors, mill wrights, engineering staff, etc.
- LNBs would require furnace upgrades, new flame safety equipment, and other facility modifications to accommodate this technology.
- The cost effectiveness of LNBs ranges from $18,300 to $42,300 per ton of NO_X removed.
- Annual performance testing costs for the RHFs is estimated to be $13,300 to comply with monitoring requirements of the Good Neighbor Plan.

Appendices

Appendix A

Estimated Low NOX Burner Installation Schedule

USS Gary Works - 84" HSM NOx Controls Evaluation
Appendix A - Estimated Low NOx Burner Installation Schedule

	-11	-10	-9	-8	-7	-6	-5	-4	-3	-2	-1	0	1	2	3	4	5
	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
Complete PAEE Paperwork																	
PAEE Approved																	
Engineering for emissions sampling infrastructure																	
Partial install of emissions sampling infrastructure to allow baseline testing (scaffolding, umbilical piping)																	
Air Permit Application Preparations																	
Baseline test complete																	
Obtain Air Permit - Permitting, Public Hearings, etc.																	
Perform detailed furnace study																	
Complete detailed design of burners																	
Complete burner installation scope and specification																	
Burner installation bids - price for each furnace separately																	
Complete AR Paperwork																	
AR Approved																	
Completion of emissions sampling infrastructure (permanent platforms, ladders, etc.)																	
Order for furnaces 1-4 burners placed																	
Procure materials for burners																	
Fabrication of burners furnace 1																	
Shipment of burners for furnace 1																	
Place burner installation PO for furnace 1																	
Furnace 1 mobilization material procurement																	
Furnace 1 Outage																	
Furnace 1 Performance Testing																	
Lessons Learned Furnace 1 - installation specification updated																	
Fabrication of burners furnace 2																	
Shipment of burners for furnace 2																	
Place burner installation PO for furnace 2																	
Furnace 2 mobilization material procurement																	
Furnace 2 Outage																	
Furnace 2 Performance Testing																	
Lessons Learned Furnace 2 - installation specification updated																	
Fabrication of burners furnace 3																	
Shipment of burners for furnace 3																	
Place burner installation PO for furnace 3																	
Furnace 3 mobilization material procurement																	
Furnace 3 Outage																	
Furnace 3 Performance Testing																	
Lessons Learned Furnace 3 - installation specification updated																	
Fabrication of burners furnace 4																	
Shipment of burners for furnace 4																	
Place burner installation PO for furnace 4																	
Furnace 4 mobilization material procurement																	
Furnace 4 Outage																	
Furnace 4 Performance Testing																	

USS Gary Works - 84" HSM NOx Controls Evaluation
Appendix A - Estimated Low NOx Burner Installation Schedule

	6	7	8	9	10	11	12	13	14	15	16	17
	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
Complete PAEE Paperwork												
PAEE Approved												
Engineering for emissions sampling infrastructure												
Partial install of emissions sampling infrastructure to allow baseline testing (scaffolding, umbilical piping)												
Air Permit Application Preparations												
Baseline test complete												
Obtain Air Permit - Permitting, Public Hearings, etc.												
Perform detailed furnace study												
Complete detailed design of burners												
Complete burner installation scope and specification												
Burner installation bids - price for each furnace separately												
Complete AR Paperwork												
AR Approved												
Completion of emissions sampling infrastructure (permanent platforms, ladders, etc.)												
Order for furnaces 1-4 burners placed												
Procure materials for burners												
Fabrication of burners furnace 1												
Shipment of burners for furnace 1												
Place burner installation PO for furnace 1												
Furnace 1 mobilization material procurement												
Furnace 1 Outage												
Furnace 1 Performance Testing												
Lessons Learned Furnace 1 - installation specification updated												
Fabrication of burners furnace 2												
Shipment of burners for furnace 2												
Place burner installation PO for furnace 2												
Furnace 2 mobilization material procurement												
Furnace 2 Outage												
Furnace 2 Performance Testing												
Lessons Learned Furnace 2 - installation specification updated												
Fabrication of burners furnace 3												
Shipment of burners for furnace 3												
Place burner installation PO for furnace 3												
Furnace 3 mobilization material procurement												
Furnace 3 Outage												
Furnace 3 Performance Testing												
Lessons Learned Furnace 3 - installation specification updated												
Fabrication of burners furnace 4												
Shipment of burners for furnace 4												
Place burner installation PO for furnace 4												
Furnace 4 mobilization material procurement												
Furnace 4 Outage												
Furnace 4 Performance Testing												

USS Gary Works - 84" HSM NOx Controls Evaluation
Appendix A - Estimated Low NOx Burner Installation Schedule

	18	19	20	21	22	23	24	25	26	27	28	29
	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26
Complete PAEE Paperwork												
PAEE Approved												
Engineering for emissions sampling infrastructure												
Partial install of emissions sampling infrastructure to allow baseline testing (scaffolding, umbilical piping)												
Air Permit Application Preparations												
Baseline test complete												
Obtain Air Permit - Permitting, Public Hearings, etc.												
Perform detailed furnace study												
Complete detailed design of burners												
Complete burner installation scope and specification												
Burner installation bids - price for each furnace separately												
Complete AR Paperwork												
AR Approved												
Completion of emissions sampling infrastructure (permanent platforms, ladders, etc.)												
Order for furnaces 1-4 burners placed												
Procure materials for burners												
Fabrication of burners furnace 1												
Shipment of burners for furnace 1												
Place burner installation PO for furnace 1												
Furnace 1 mobilization material procurement												
Furnace 1 Outage												
Furnace 1 Performance Testing												
Lessons Learned Furnace 1 - installation specification updated												
Fabrication of burners furnace 2	■											
Shipment of burners for furnace 2		■										
Place burner installation PO for furnace 2												
Furnace 2 mobilization material procurement	■	■	■									
Furnace 2 Outage				■								
Furnace 2 Performance Testing					■							
Lessons Learned Furnace 2 - installation specification updated					■							
Fabrication of burners furnace 3			■	■	■							
Shipment of burners for furnace 3						■						
Place burner installation PO for furnace 3						■						
Furnace 3 mobilization material procurement							■	■	■			
Furnace 3 Outage										■		
Furnace 3 Performance Testing											■	
Lessons Learned Furnace 3 - installation specification updated											■	
Fabrication of burners furnace 4							■	■	■			
Shipment of burners for furnace 4										■		
Place burner installation PO for furnace 4												■
Furnace 4 mobilization material procurement												
Furnace 4 Outage												
Furnace 4 Performance Testing												

USS Gary Works - 84" HSM NOx Controls Evaluation
Appendix A - Estimated Low NOx Burner Installation Schedule

	30	31	32	33	34	36	36	37	38	39	40	41
	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
Complete PAEE Paperwork												
PAEE Approved												
Engineering for emissions sampling infrastructure												
Partial install of emissions sampling infrastructure to allow baseline testing (scaffolding, umbilical piping)												
Air Permit Application Preparations												
Baseline test complete												
Obtain Air Permit - Permitting, Public Hearings, etc.												
Perform detailed furnace study												
Complete detailed design of burners												
Complete burner installation scope and specification												
Burner installation bids - price for each furnace separately												
Complete AR Paperwork												
AR Approved												
Completion of emissions sampling infrastructure (permanent platforms, ladders, etc.)												
Order for furnaces 1-4 burners placed												
Procure materials for burners												
Fabrication of burners furnace 1												
Shipment of burners for furnace 1												
Place burner installation PO for furnace 1												
Furnace 1 mobilization material procurement												
Furnace 1 Outage												
Furnace 1 Performance Testing												
Lessons Learned Furnace 1 - installation specification updated												
Fabrication of burners furnace 2												
Shipment of burners for furnace 2												
Place burner installation PO for furnace 2												
Furnace 2 mobilization material procurement												
Furnace 2 Outage												
Furnace 2 Performance Testing												
Lessons Learned Furnace 2 - installation specification updated												
Fabrication of burners furnace 3												
Shipment of burners for furnace 3												
Place burner installation PO for furnace 3												
Furnace 3 mobilization material procurement												
Furnace 3 Outage												
Furnace 3 Performance Testing												
Lessons Learned Furnace 3 - installation specification updated												
Fabrication of burners furnace 4												
Shipment of burners for furnace 4												
Place burner installation PO for furnace 4												
Furnace 4 mobilization material procurement												
Furnace 4 Outage												
Furnace 4 Performance Testing												

Appendix B

RHF LNB Control Costs

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - Cost Summary
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

NO_x Control Cost Summary (emissions and costs are for each furnace individually)

Control Technology	Control Eff %[a]	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton
Low NOx Burners (LNB) - Vendor 1	41%	89.6	63.1	$7,111,695	$1,155,629	$18,301
Low NOx Burners (LNB) - Vendor 2	20%	122.2	30.6	$8,072,695	$1,293,776	$42,343
Low NOx Burners (LNB) - Vendor 3	40%	91.7	61.1	$11,593,945	$1,799,972	$29,455

a - Calculated control efficiencies are not based on EPA certified performance test methods due to lack of access to appropriate test locations. Therefore, the control efficiencies may not appropriately represent what can be achieved from existing baseline conditions and the required reductions in the Good Neighbor Plan may not be feasible.

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - Utility and Chemical Supply Costs
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Note: emissions and costs are for each furnace individually **Study Year** 2023

2023

Item	Unit Cost	Units	Cost	Year	Data Source
Operating Labor	74	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet
Maintenance Labor	74	$/hr			Assumed to be equivalent to operating labor
Other					
Sales Tax	7%			2020	Indiana sales tax rate
Interest Rate	8.25%			2023	Current prime bank rate
Operating Information					
Ozone Season Operating Hours	3,395	Hours			May 1st - September 30, adjusted for USS planned weekly maintenance outages
Annual Op. Hrs	8,100	Hours			USS Estimate
Utilization Rate	100%				Assumed
Design Capacity	600	MMBTU/hr			Permit listed duty
Equipment Life	20	yrs			Assumed
Plant Elevation	607	Feet above sea level			Plant elevation
	Baseline Emissions				
Pollutant	**Ton/Year**				
Nitrous Oxides (NOx)	152.8				Calculated
Baseline NOx performance	0.15	lb/MMBtu			Average of performance testing data
LNB NO_x Performance - Vendor 1	0.09	lb/MMBtu			Vendor guaranteed performance at 800F air preheat
Control efficiency - Vendor 1	41%				Calculated
LNB NO_x Performance - Vendor 2	0.12	lb/MMBtu			Vendor guaranteed performance at 800F air preheat
Control efficiency - Vendor 2	20%				Calculated
LNB NO_x Performance - Vendor 3	0.09	lb/MMBtu			2020 Quote LHV basis
Control efficiency - Vendor 3	40%				Calculated

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 1
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Note: emissions and costs are for each furnace individually

Desgin Capacity	600	MMBtu/hr
Expected Utiliztion Rate	100%	
Expected Ozone Season Operating Hours	3,395	Hours
Annual Interest Rate	8.3%	
Expected Equipment Life	20	yrs

CONTROL EQUIPMENT COSTS

Capital Costs							
Total Capital Investment (TCI) = DC + IC							**7,111,695**
Operating Costs							
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.					83,307
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost					1,072,321
Total Annual Cost (Annualized Capital Cost + Operating Cost)							**1,155,629**

EMISSION CONTROL COST EFFECTIVENESS

Pollutant	**Baseline Emis. T/yr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10				-	NA
Total Particulates				-	NA
Nitrous Oxides (NOx)	152.8	0.09	89.6	63.1	18,301
Sulfur Dioxide (SO_2)				-	NA

Notes & Assumptions

1. Refer to the *Vendor Summary* tab for Details
2. Assumed 0.1 and 0.5 hr/shift respectively for operator and maintenance labor
3. Controlled emission factor based on vendor estimated burner performance

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 1
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

CAPITAL COSTS			
Direct Capital Costs			
Equipment		Refer to *Vendor Summary* tab for Details	$ 2,229,625
Installation		Refer to *Vendor Summary* tab for Details	$ 1,494,250
Engineering		Refer to *Vendor Summary* tab for Details	$ 304,320
Start-up and Commissioning		Refer to *Vendor Summary* tab for Details	$ 381,000
Capital Spares		Refer to *Vendor Summary* tab for Details	$ 137,500
Non-Capital Spares		Refer to *Vendor Summary* tab for Details	$ 90,000
Cost Work		Refer to *Vendor Summary* tab for Details	$ 2,475,000
Total Capital Investment (TCI) = DC + IC			**$ 7,111,695**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	73.79	$/Hr, 0.1 hr/8 hr shift, 8100 hr/yr	7,471
Supervisor	15%	15% of Operator Costs	1,121
Maintenance (2)			
Maintenance Labor	73.79	$/Hr, 0.5 hr/8 hr shift, 8100 hr/yr	37,357
Maintenance Materials	100%	of maintenance labor costs	37,357
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**83,307**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	49,984
Administration (2% total capital costs)	2%	of total capital costs (TCI)	142,234
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	71,117
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	71,117
Capital Recovery	10%	for a 20- year equipment life and a 8.25% interest rate	737,869
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,072,321**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,155,629**

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 1
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Capital Recovery Factors		
Primary Installation		
Interest Rate	8.25%	
Equipment Life	20	years
CRF	0.1038	

Operating Cost Calculations			**Annual hours of operation:**			8,100	
			Utilization Rate:			100%	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	73.79	$/Hr	0.1	hr/8 hr shift	101	7,471	$/Hr, 0.1 hr/8 hr shift, 8100 hr/yr
Supervisor	15%	of Op.			NA	1,121	15% of Operator Costs
Maintenance							
Maint Labor	73.79	$/Hr	0.5	hr/8 hr shift	506	37,357	$/Hr, 0.5 hr/8 hr shift, 8100 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	37,357	100% of Maintenance Labor

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 2
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Note: emissions and costs are for each furnace individually

Desgin Capacity	600	MMBtu/hr
Expected Utiliztion Rate	100%	
Expected Ozone Season Operating Hours	3,395	Hours
Annual Interest Rate	8.3%	
Expected Equipment Life	20	yrs

CONTROL EQUIPMENT COSTS

Capital Costs							
Total Capital Investment (TCI) = DC + IC							**8,072,695**
Operating Costs							
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.					83,307
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost					1,210,469
Total Annual Cost (Annualized Capital Cost + Operating Cost)							**1,293,776**

EMISSION CONTROL COST EFFECTIVENESS

Pollutant	**Baseline Emis. T/yr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10				-	NA
Total Particulates				-	NA
Nitrous Oxides (NOx)	152.8	0.12	122.2	30.6	42,343
Sulfur Dioxide (SO_2)				-	NA

Notes & Assumptions

1 Refer to the *Vendor Summary* tab for Details

2 Assumed 0.1 and 0.5 hr/shift respectively for operator and maintenance labor

3 Controlled emission factor based on vendor estimated burner performance

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 2
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

CAPITAL COSTS			
Direct Capital Costs			
Equipment	Refer to *Vendor Summary* tab for Details	$	3,100,000
Installation	Refer to *Vendor Summary* tab for Details	$	1,629,250
Engineering	Refer to *Vendor Summary* tab for Details	$	288,945
Start-up and Commissioning	Refer to *Vendor Summary* tab for Details	$	309,500
Capital Spares	Refer to *Vendor Summary* tab for Details	$	180,000
Non-Capital Spares	Refer to *Vendor Summary* tab for Details	$	90,000
Cost Work	Refer to *Vendor Summary* tab for Details	$	2,475,000
Total Capital Investment (TCI) = DC + IC		**$**	**8,072,695**

OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	73.79	$/Hr, 0.1 hr/8 hr shift, 8100 hr/yr	7,471
Supervisor	15%	15% of Operator Costs	1,121
Maintenance (2)			
Maintenance Labor	73.79	$/Hr, 0.5 hr/8 hr shift, 8100 hr/yr	37,357
Maintenance Materials	100%	of maintenance labor costs	37,357
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**83,307**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	49,984
Administration (2% total capital costs)	2%	of total capital costs (TCI)	161,454
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	80,727
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	80,727
Capital Recovery	10%	for a 20- year equipment life and a 8.25% interest rate	837,577
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,210,469**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,293,776**

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 2
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Capital Recovery Factors		
Primary Installation		
Interest Rate	8.25%	
Equipment Life	20	years
CRF	0.1038	

Operating Cost Calculations			**Annual hours of operation:**			8,100	
			Utilization Rate:			100%	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	73.79	$/Hr	0.1	hr/8 hr shift	101	7,471	$/Hr, 0.1 hr/8 hr shift, 8100 hr/yr
Supervisor	15%	of Op.			NA	1,121	15% of Operator Costs
Maintenance							
Maint Labor	73.79	$/Hr	0.5	hr/8 hr shift	506	37,357	$/Hr, 0.5 hr/8 hr shift, 8100 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	37,357	100% of Maintenance Labor

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 3
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Note: emissions and costs are for each furnace individually

Desgin Capacity	600	MMBtu/hr
Expected Utiliztion Rate	100%	
Expected Ozone Season Operating Hours	3,395	Hours
Annual Interest Rate	8.3%	
Expected Equipment Life	20	yrs

CONTROL EQUIPMENT COSTS

Capital Costs							
Total Capital Investment (TCI) = DC + IC							**11,593,945**
Operating Costs							
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.					83,307
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost					1,716,665
Total Annual Cost (Annualized Capital Cost + Operating Cost)							**1,799,972**

EMISSION CONTROL COST EFFECTIVENESS

Pollutant	**Baseline Emis. T/yr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10				-	NA
Total Particulates				-	NA
Nitrous Oxides (NOx)	152.8	0.09	91.7	61.1	29,455
Sulfur Dioxide (SO_2)				-	NA

Notes & Assumptions

1 Refer to the *Vendor Summary* tab for Details

2 Assumed 0.1 and 0.5 hr/shift respectively for operator and maintenance labor

3 Controlled emission factor based on vendor estimated burner performance

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 3
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

CAPITAL COSTS			
Direct Capital Costs			
Equipment	Refer to *Vendor Summary* tab for Details	$	6,650,000
Installation	Refer to *Vendor Summary* tab for Details	$	1,838,000
Engineering	Refer to *Vendor Summary* tab for Details	$	243,945
Start-up and Commissioning	Refer to *Vendor Summary* tab for Details	$	147,000
Capital Spares	Refer to *Vendor Summary* tab for Details	$	150,000
Non-Capital Spares	Refer to *Vendor Summary* tab for Details	$	90,000
Cost Work	Refer to *Vendor Summary* tab for Details	$	2,475,000
Total Capital Investment (TCI) = DC + IC		**$**	**11,593,945**

OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	73.79	$/Hr, 0.1 hr/8 hr shift, 8100 hr/yr	7,471
Supervisor	15%	15% of Operator Costs	1,121
Maintenance (2)			
Maintenance Labor	73.79	$/Hr, 0.5 hr/8 hr shift, 8100 hr/yr	37,357
Maintenance Materials	100%	of maintenance labor costs	37,357
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**83,307**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	49,984
Administration (2% total capital costs)	2%	of total capital costs (TCI)	231,879
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	115,939
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	115,939
Capital Recovery	10%	for a 20- year equipment life and a 8.25% interest rate	1,202,923
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,716,665**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,799,972**

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 3
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Capital Recovery Factors		
Primary Installation		
Interest Rate	8.25%	
Equipment Life	20	years
CRF	0.1038	

Operating Cost Calculations			**Annual hours of operation:**			8,100	
			Utilization Rate:			100%	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	73.79	$/Hr	0.1	hr/8 hr shift	101	7,471	$/Hr, 0.1 hr/8 hr shift, 8100 hr/yr
Supervisor	15%	of Op.			NA	1,121	15% of Operator Costs
Maintenance							
Maint Labor	73.79	$/Hr	0.5	hr/8 hr shift	506	37,357	$/Hr, 0.5 hr/8 hr shift, 8100 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	37,357	100% of Maintenance Labor

USS Gary - HSM NOx Controls Evaluation

Appendix B - Low NOx Burner Cost Estimates (All Furnaces)

Vendor 1 Estimate

Burners Ultra-Low Nox Burners

New burners will fit inside existing bodies (plug & play)

Flame safety included:

- Covert the soak zone to a supervised system to bring the soak zone above auto-ignition
- 16 New Soak Burners, Direct Spark Ignition, Flame Rod, Transformer, Ignition Cable, Necessary Gas and Air Valves
- Double Block Valves for 40 Soak Burners
- New NFPA Compliant Main Fuel Train
- New NFPA Compliant Pilot Train - Required for Cold Start Operation in Bottom Heat.
- To Accommodate Flame Supervision in the Soak Section and Cold Start Capabilities in the Bottom Heat Section.

Included in cost scope:

- Upgrades to combustion air system and recuperators
- NG piping replacement as required - restricted piping... coke oven gas remediations
- Upgrades to Level 0/1 components
- Refractory

Task	Item	Vendor	Estimate	Contingency		Amount
1000	**Equipment**					**$ 8,918,500**
	Burners	VENDOR 1	$ 7,320,000	5%	$ 366,000	$ 7,686,000
	Emissions Sampling/Testing Infrastructure		$ 400,000	20%	$ 80,000	$ 480,000
	Peripheral Control Equipment		$ 200,000	20%	$ 40,000	$ 240,000
	Refractory/Piping Materials		$ 300,000	20%	$ 60,000	$ 360,000
					$ 152,500	$ 152,500
1100	**Installation**					**$ 5,977,000**
	Burners		$ 3,800,000	20%	$ 760,000	$ 4,560,000
	Emissions Sampling/Testing Infrastructure		$ 850,000	30%	$ 255,000	$ 1,105,000
	Model/Pie Updates		$ 90,000	30%	$ 27,000	$ 117,000
	Level 1 Updates		$ 150,000	30%	$ 45,000	$ 195,000
2900	**Engineering**					**$ 1,217,280**
	Impact Analysis and Study		$ 53,600	5%	$ 2,680	$ 56,280
	Technical Support for Impact Study		$ 20,000	5%	$ 1,000	$ 21,000
	Detailed Furnace Study	VENDOR 1	$ 230,000	5%	$ 11,500	$ 241,500
	Design of Emissions Sampling/Testing Infrastructure		$ 150,000	20%	$ 30,000	$ 180,000
	Installation Specification Development		$ 150,000	20%	$ 30,000	$ 180,000
	Constructability		$ 60,000	20%	$ 12,000	$ 72,000
	Furnace Model Modifications	VENDOR 1	$ 60,000	20%	$ 12,000	$ 72,000
	Level I Design - Burners/Flame Safety/Consulting		$ 90,000	20%	$ 18,000	$ 108,000
	As-Built Drawings - MOC		$ 160,000	20%	$ 32,000	$ 192,000
	Drawing Management		$ 90,000	5%	$ 4,500	$ 94,500
2910	**Start-up and Commissioning**					**$ 1,524,000**
	Field Supervision	VENDOR 1	$ 780,000	20%	$ 156,000	$ 936,000
	Scheduling and Cost Control		$ 90,000	20%	$ 18,000	$ 108,000
	Construction Management		$ 400,000	20%	$ 80,000	$ 480,000
3000	**Capital Spares (>$10,000)**					**$ 550,000**
	Capital Spares		$ 500,000	10%	$ 50,000	$ 550,000
5000	**Non-Capital Spares (<$10,000)**					**$ 360,000**
	Spare Parts		$ 300,000	20%	$ 60,000	$ 360,000
6000	**Cost Work**					**$ 9,900,000**
	Cost Work		$ 8,250,000	20%	$ 1,650,000	$ 9,900,000

CAPITAL ESTIMATE	**$ 18,186,780**
EXPENSE ESTIMATE	**$ 10,260,000**
TOTAL ESTIMATE	**$ 28,446,780**

USS Gary - HSM NOx Controls Evaluation
Appendix B - Low NOx Burner Cost Estimates (All Furnaces)
Vendor 1 Estimate

Vendor 2 Estimate

Burners — New burners
All four burner walls will be reworked to incorporate the necessary converging tile for the required air injection velocity.
Need to replace combustion air fans

Flame safety included:
Four auxiliary side fired burners to bring the soak zone above auto-ignition.
Replacement of the burner bodies in the bottom heat zone to accept a fully compliant piloted ignition system
Addition of injectors only to the top heat and top and bottom preheat zones that will be interlocked to 1400 °F permissive.
Proof of purge and low fire switches will be installed on existing air metering orifice plates
Safety PLC is included to perform the necessary flame monitoring and natural gas path select functionality

Included in cost scope:
Upgrades to combustion air system and recuperators
NG piping replacement as required - restricted piping... coke oven gas remediations
Upgrades to Level 0/1 components
Refractory

Task	Item	Vendor	Estimate	Contingency		Amount
1000	**Equipment**					**$ 12,400,000**
	Burners	VENDOR 2	$ 10,400,000	5%	$ 520,000	$ 10,920,000
	Emissions Sampling/Testing Infrastructure		$ 400,000	20%	$ 80,000	$ 480,000
	Peripheral Control Equipment (Safety PLC Provided)		$ 125,000	20%	$ 25,000	$ 150,000
	Refractory/Piping Materials		$ 600,000	20%	$ 120,000	$ 720,000
	Combustion Air Fans		$ 100,000	30%	$ 30,000	$ 130,000
1100	**Installation**					**$ 6,517,000**
	Burners		$ 4,000,000	20%	$ 800,000	$ 4,800,000
	Combustion Air Fans		$ 300,000	30%	$ 90,000	$ 390,000
	Emissions Sampling/Testing Infrastructure		$ 800,000	30%	$ 240,000	$ 1,040,000
	Model/Pie Updates		$ 90,000	30%	$ 27,000	$ 117,000
	Level 1 Updates		$ 125,000	30%	$ 45,000	$ 170,000
2900	**Engineering**					**$ 1,155,780**
	Impact Analysis and Study		$ 53,600	5%	$ 2,680	$ 56,280
	Technical Support for Impact Study		$ 20,000	5%	$ 1,000	$ 21,000
	Detailed Furnace Study	VENDOR 2	$ 150,000	20%	$ 30,000	$ 180,000
	Design of Emissions Sampling/Testing Infrastructure		$ 150,000	20%	$ 30,000	$ 180,000
	Installation Specification Development		$ 150,000	20%	$ 30,000	$ 180,000
	Constructability		$ 60,000	20%	$ 12,000	$ 72,000
	Furnace Model Modifications	VENDOR 2	$ 60,000	20%	$ 12,000	$ 72,000
	Level I Design - Burners/Flame Safety/Consulting		$ 90,000	20%	$ 18,000	$ 108,000
	As-Built Drawings - MOC		$ 160,000	20%	$ 32,000	$ 192,000
	Drawing Management		$ 90,000	5%	$ 4,500	$ 94,500
2910	**Start-up and Commissioning**					**$ 1,238,000**
	Field Supervision	VENDOR 2	$ 500,000	30%	$ 150,000	$ 650,000
	Scheduling and Cost Control		$ 90,000	20%	$ 18,000	$ 108,000
	Construction Management		$ 400,000	20%	$ 80,000	$ 480,000
3000	**Capital Spares (>$10,000)**					**$ 720,000**
	Capital Spares (combustion air fan added)		$ 600,000	20%	$ 120,000	$ 720,000
5000	**Non-Capital Spares (<$10,000)**					**$ 360,000**
	Spare Parts		$ 300,000	20%	$ 60,000	$ 360,000
6000	**Cost Work**					**$ 9,900,000**
	Cost Work		$ 8,250,000	20%	$ 1,650,000	$ 9,900,000

CAPITAL ESTIMATE	**$ 22,030,780**
EXPENSE ESTIMATE	**$ 10,260,000**
TOTAL ESTIMATE	**$ 32,290,780**

USS Gary - HSM NOx Controls Evaluation
Appendix B - Low NOx Burner Cost Estimates (All Furnaces)
Vendor 1 Estimate

Vendor 3 Estimate

Burners New burners
Moderate shell steel and refractory port modifications
The combustion air blower will be replaced with higher pressure fans
existing recuperator, zone orifice plates and flow control valves.
Burner drop ductwork will need to be modified as required to connect to the new burners.
New burner expansion joints will be provided along with new burner isolation valves.
Gas piping from the gas train to the burners will remain in place, and existing orifice plates and flow control valves will remain in service
Piping modification to suit the new burners will be made at the burner drops
A new level 1 control system, including new PLC hardware, remote I/O panels, HMI screens is included.

Flame safety included:
Gas train for the furnace must be modified to comply with the latest NFPA-86 standards
The combustion system will be designed to use the top and bottom heat zones as the light-up zones
The top and bottom preheat zones will be ignited when the zones are above auto-ignition bypass temperature
The furnace will be provided with new purge and safety checks for proper ignition sequence as mandated by the NFPA.
Ignition burners will have spark ignited pilot burners with UV detector type flame supervision
A burner management system panel will be included to house the electronic components

Task	Item	Vendor	Estimate	Contingency		Amount
1000	**Equipment**					**$ 26,600,000**
	Burners (Flame Safety Included, comb air fans)	Vendor 3	$ 24,000,000	5%	$ 1,200,000	$ 25,200,000
	Emissions Sampling/Testing Infrastructure		$ 400,000	20%	$ 80,000	$ 480,000
	Refractory/Piping Materials (burner walls need to be reworked)		$ 800,000	15%	$ 120,000	$ 920,000
1100	**Installation**					**$ 7,352,000**
	Burners		$ 5,000,000	20%	$ 1,000,000	$ 6,000,000
	Emissions Sampling/Testing Infrastructure		$ 800,000	30%	$ 240,000	$ 1,040,000
	Model/Pie Updates		$ 90,000	30%	$ 27,000	$ 117,000
	Level 1 Updates		$ 150,000	30%	$ 45,000	$ 195,000
2900	**Engineering**					**$ 975,780**
	Impact Analysis and Study		$ 53,600	5%	$ 2,680	$ 56,280
	Technical Support for Impact Study		$ 20,000	5%	$ 1,000	$ 21,000
	Design of Emissions Sampling/Testing Infrastructure		$ 150,000	20%	$ 30,000	$ 180,000
	Installation Specification Development		$ 150,000	20%	$ 30,000	$ 180,000
	Constructability		$ 60,000	20%	$ 12,000	$ 72,000
	Furnace Model Modifications	Vendor 3	$ 60,000	20%	$ 12,000	$ 72,000
	Level I Design - Burners/Flame Safety/Consulting		$ 90,000	20%	$ 18,000	$ 108,000
	As-Built Drawings - MOC		$ 160,000	20%	$ 32,000	$ 192,000
	Drawing Management		$ 90,000	5%	$ 4,500	$ 94,500
2910	**Start-up and Commissioning**					**$ 588,000**
	Scheduling and Cost Control		$ 90,000	20%	$ 18,000	$ 108,000
	Construction Management		$ 400,000	20%	$ 80,000	$ 480,000
3000	**Capital Spares (>$10,000)**					**$ 600,000**
	Capital Spares (combustion air fan added)		$ 500,000	20%	$ 100,000	$ 600,000
5000	**Non-Capital Spares (<$10,000)**					**$ 360,000**
	Spare Parts		$ 300,000	20%	$ 60,000	$ 360,000
6000	**Cost Work**					**$ 9,900,000**
	Cost Work		$ 8,250,000	20%	$ 1,650,000	$ 9,900,000

CAPITAL ESTIMATE	**$ 36,115,780**
EXPENSE ESTIMATE	**$ 10,260,000**
TOTAL ESTIMATE	**$ 46,375,780**